

LOW-CARBON HEAT SOLUTIONS FOR HEAVY INDUSTRY: SOURCES, OPTIONS, AND COSTS TODAY

BY S. JULIO FRIEDMANN, ZHIYUAN FAN, AND KE TANG
OCTOBER 2019

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EXECUTIVE SUMMARY

Recent studies indicate there is an urgent need to dramatically reduce the greenhouse gas emissions from heavy industrial applications (including cement, steel, petrochemicals, glass and ceramics, and refining). Heavy industry produces roughly 22 percent of global CO₂ emissions. Of these, roughly 40 percent (about 10 percent of total emissions) is the direct consequence of combustion to produce high-quality heat, almost entirely from the combustion of fossil fuels. This is chiefly because these fuels are relatively cheap, are widely available in large volumes, and produce high-temperature heat in great amounts.

Many industrial processes require very large amounts of thermal energy at very high temperatures (more than 300°C and often more than 800°C). For example, conventional steel blast furnaces operate at about 1,100°C, and conventional cement kilns operate at about 1,400°C. In addition, many commercial industrial facilities require continuous operation or operation on demand. The nature of industrial markets creates challenges to the decarbonization of industrial heat. In some cases (e.g., steel, petrochemicals), global commodity markets govern product trade and price. Individual national action on the decarbonization of heavy industry can lead to trade disadvantage, which can be made acute for foundational domestic industries (in some cases, with national security implications). This can also lead to offshoring of production and assets, leading to carbon “leakage” as well as local job and revenue loss (with political consequences). In many cases, lack of options could lead to dramatic price increases for essential products (e.g., cement for concrete, an essential building material). Risk of carbon leakage, price escalation, and trade complexity limits the range of policy applications available to address this decarbonization need.

To explore the topic of industrial heat decarbonization, the authors undertook an initial review of all options to supply high temperature, high flux, and high volume heat for a subset of major industrial applications: cement manufacturing, primary iron and steel production, methanol and ammonia synthesis, and glassmaking. From the initial comprehensive set of potential heat supply options, the authors selected a subset of high relevance and common consideration:

- Biomass and biofuel combustion
- Hydrogen combustion (including hydrogen produced from natural gas with 89 percent carbon capture (blue hydrogen) and hydrogen produced from electrolysis of water using renewable power (green hydrogen))
- Electrical heating (including electrical resistance heating and radiative heating (e.g., microwaves))
- Nuclear heat production (including conventional and advanced systems)
- The application of post-combustion carbon capture, use, and storage (CCUS) to industrial heat supply and to the entire facility, as a basis for comparison



The authors focus on substitutions and retrofits to existing facilities and on four primary concerns: cost, availability, viability of retrofit/substitution, and life-cycle footprint. In short, the paper finds:

- **All approaches have substantial limitations or challenges to commercial deployment.** Some processes (e.g., steelmaking) will likely have difficulty accepting options for substitution. All options would substantially increase the production cost and wholesale price of industrial products. For many options (e.g., biomass or electrification), the life-cycle carbon footprint or efficiency of heat deposition are highly uncertain and cannot be resolved simply. This complicates crafting sound policy and assessing technical options and viability.
- **Most substitute supply options for low-carbon heat appear more technically challenging and expensive than retrofits for CCUS.** Even given the uncertainties around costs and documented complexities in applying CO₂ capture to industrial systems, it may prove simpler and cheaper to capture and store CO₂. CCUS would have the added benefit of capturing emissions from by-product industrial chemistry, which can represent 20–50 percent of facility emissions and would not be captured through heat substitution alone. Critically, CCUS is actionable today, providing additional GHG mitigation to industrial heat and process emissions as other options mature and become economically viable.
- **Hydrogen combustion provided the readiest source of heat of all the options assessed, was the simplest to apply (including retrofit), and was the most tractable life-cycle basis.** Today, hydrogen produced from reforming natural gas and decarbonized with CCUS (blue hydrogen) has the best cost profile for most applications and the most mature supply chain, and it would commonly add 10–50 percent to wholesale production costs. It also could provide a pathway to increase substitution with hydrogen produced by electrolysis of water from carbon-free electricity (green hydrogen), which today would increase costs 200–800 percent but would drop as low-carbon power supplies grow and electrolyzer costs drop. Hydrogen-based industrial heat provides an actionable pathway to start industrial decarbonization at once, particularly in the petrochemical, refining, and glass sectors, while over time reducing cost and contribution of fossil sources. However, substitution of hydrogen will prove more difficult or infeasible for steel and cement, which might require more comprehensive redesign and investment.
- **Most of the other options appear to add substantially to final production costs—commonly twice that of blue hydrogen substitution or CCUS—and are more difficult to implement. However, all options show the potential for substantial cost reductions.** An innovation agenda remains a central important undertaking and likely would yield near-term benefits in cost reduction, ease of implementation, and a lower life-cycle carbon footprint. Prior lack of focus on industrial heat supplies as a topic leave open many possibilities for improvement, and dedicated research, development, and demonstration (RD&D) programs could make substantial near-term progress. To avoid commercial and technical failure, government innovation programs should work closely with industry leaders at all levels of investigation.



- **New policies specific to heavy industry heat and decarbonization are required to stimulate market adoption. Policies must address concerns about leakage and global commodity trade effects as well as the environmental consequences.** These policies could include sets of incentives (e.g., government procurement mandates, tax credits, feed-in tariffs) large enough to overcome the trade and cost concerns. Alternatively, policies like border adjustment tariffs would help protect against leakage or trade impacts. Because all options suffer from multiple challenges or deficiencies, innovation policy (including programs that both create additional options and improve existing options) is essential to deliver rapid progress in industrial heat decarbonization and requires new programs and funding. As a complement to innovation policy and governance, more work is needed to gather and share fundamental technical and economic data around industrial heat sources, efficiency, use, and footprint.



INTRODUCTION

Recent studies have underscored the three unpleasant truths about man-made climate change: It's chiefly caused by human activity, the consequences are severe, and the problem is growing worse. A report from the Intergovernmental Panel on Climate Change (IPCC)¹ concluded that it is impossible to reach a stabilization scenario at 1.5°C above preindustrial levels without enormous volumes of CO₂ removal and that the differences between a 1.5°C and a 2°C stabilization are substantial (e.g., a loss of between 70–90 percent and 99 percent of corals). A recent UN report underscored the dramatic damage to ecosystems and extinction of millions of species from man-made climate change.² Concentrations of CO₂ in the atmosphere have reached about 415 ppm this year,³ the first time in three million years. And many groups have concluded independently that after a short period of near-zero growth, global greenhouse gas (GHG) emissions (chiefly CO₂) have grown for the past two years.⁴

An important contributor to increased CO₂ emissions in the last two years is heavy industry.⁵ Today, industrial GHG emissions represent 22 percent of annual emissions,⁶ chiefly flowing from a handful of industries: cement, steel, refining, petrochemicals, glass, ceramics, pulp and paper, and fertilizer production. Some of these emissions are chemical byproducts of manufacturing and synthesis (e.g., carbonate mineral devolution from cement clinker production). Some are from non-CO₂ emissions such as methane, NO_x, and black carbon aerosols.

But a very large fraction, roughly 42 percent of industrial GHG emissions or about 10 percent of global GHG emissions, are the consequence of fossil fuel combustion to produce heat for industrial processes.⁷ GHG emissions from industrial combustion are larger than global emissions from cars (roughly 6 percent) and approach all emissions from transportation sectors combined, estimated at 14–15 percent of total emissions.⁸ In the United States, 58 percent of industrial emissions are from fossil fuel combustion for heat.⁹ Today, heavy industry relies almost entirely on fossil fuels to supply process heat and lacks viable alternatives in the market. As such, decarbonizing industrial heat lies at the heart of the deep decarbonization challenge.

To ensure that deep decarbonization remains viable, decarbonizing industrial heat remains an imperative. However, there are very few options that can provide the necessary heat, flux, and constancy that many industrial processes require (see table 1). These processes operate above 300°C with high capacity factors, which severely limits the set of options for consideration.



Table 1: Options for heat

Heat option	Temperature available (°C)	Sources of heat
Hydrogen (H ₂)	2,100	Steam methane reformation or electrolysis of water
Solid biomass (wood pellets, etc.)	About 1,100	Forests, agriculture, wastes
Biofuel (biodiesels, ethanol, etc.)	About 2,200	Fermentation, chemical conversion, anaerobic digestion
Electric: Resistance (indirect)	About 1,800	Electricity
Electric: Microwave (direct)	Material specific	Electricity
Nuclear conventional	About 300	Third-generation reactors
Nuclear advanced	About 850	Advanced reactors
Solar thermal	About 1,200	Solar concentration

Sources: See Appendix B.

Given the importance of industrial heat on global and national emissions, it is perhaps surprising that little information on the subject is available. While a set of recent analyses has highlighted the importance of industrial emissions and the need for better solutions, decarbonizing heat has not been broadly recognized as an essential element of managing emissions. Where it has,¹⁰ there are limited concrete recommendations for what is actionable and material. In part, this is because governments and scholars have focused first on components of the system where more options and policies exist (e.g., decarbonizing electric power generation). In part, this is because of additional market- and trade-related concerns the industrial sector faces in decarbonization. This report seeks to provide new insight into the nature of the challenge facing industrial heat decarbonization and to help create a foundation that future policy makers, researchers, and investors can use as they begin consideration of the challenges ahead.



NATURE OF INDUSTRIAL HEAT DEMAND AND USE

Some options exist to decrease the total emissions from industry.¹¹ These include increasing energy efficiency (e.g., upgrading to more efficient technology with better equipment, improving processes), recycling (i.e., avoiding processing new raw materials), conservation and decreasing demand, material substitution (e.g., replacing concrete with cross-laminated timber as a building material), and fuel switching (mostly coal to natural gas substitution).

However, even with dramatic, economy-wide gains through these approaches, very large amounts of heat-related emissions would persist,¹² preventing the attainment of net-zero carbon emission goals. The pathway toward the net-zero carbon emission for industry is not clear, and only a few options appear viable today. Possible technical variables to consider include heat content of fuels, maximum available temperature, fuel supply and availability, life-cycle carbon footprint, direct costs, indirect costs, and more. Additional nontechnical variables include potential impacts on jobs and trade, national security and critical supply chains, economic competitiveness, and public acceptability of options.

CCUS¹³ is one approach that would be effective and has intuitive appeal. Many groups have recommended CCUS as an option for decarbonization.¹⁴ Using today's technology, CCUS deployment in industry would dramatically increase the production cost and commodity price of industrial products. It is also limited by the geographic distribution of CO₂ storage resources. Some countries, notably Japan and Korea, lack viable geological storage sites. For wide application across all regions, heat source options are needed to replace existing fossil heat sources with a much lower carbon footprint.

Heat Quality

The replacement of a heat source is possible only after ensuring the quality of heat, including temperature, flux, and availability in volume.

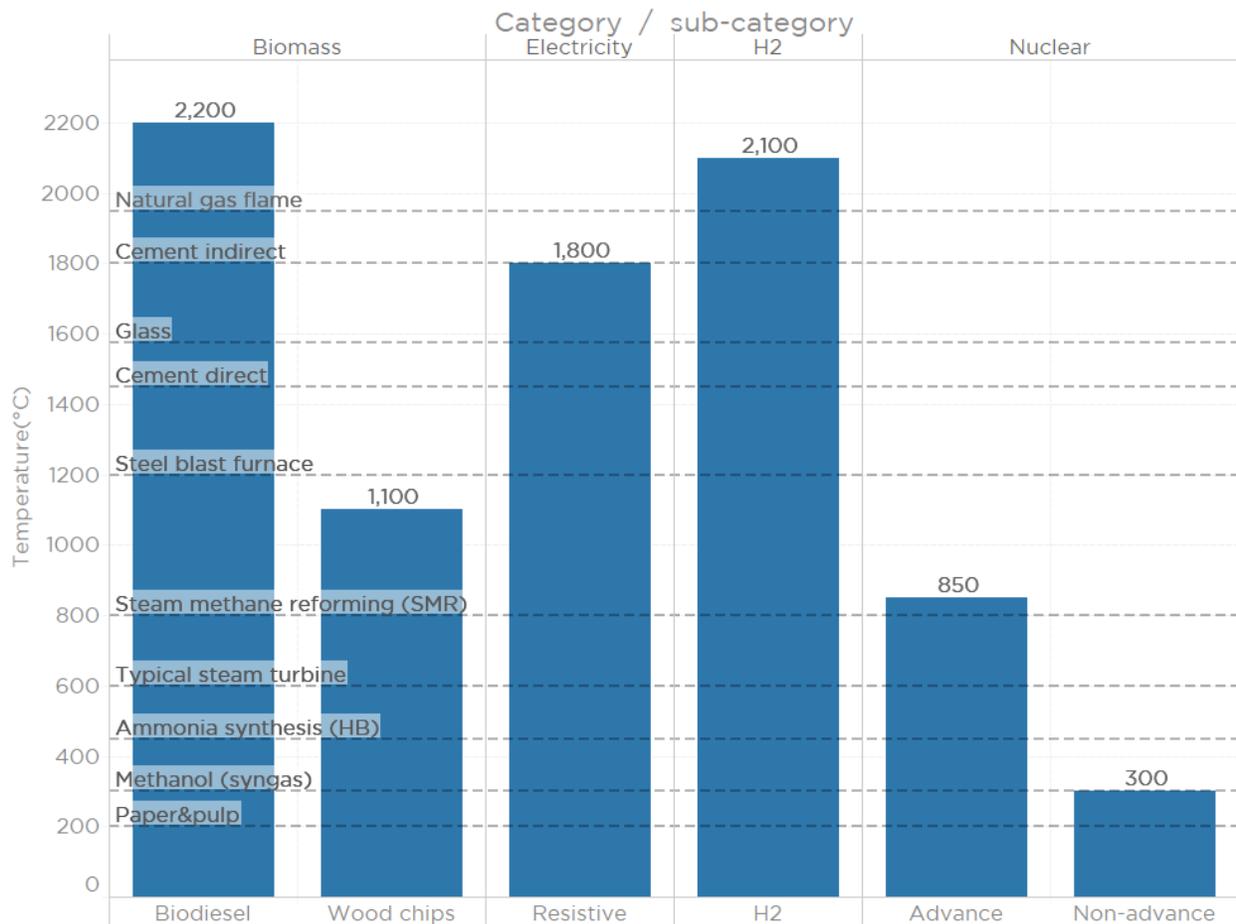
Temperature requirements: All industrial products are made through the application of high-temperature heat to feedstocks through specific physical or chemical processes (see figure 1). Temperature demands vary significantly from around 200°C to nearly 2,000°C (a typical combustion flame temperature). As a result, most of the equipment for industrial application is designed for combustion and converts heat to the required temperature for the industrial reaction (e.g., ethylene cracking or glass melting).

Theoretically, a replacement heat source is possible for certain industry applications provided that the heat source can reach reaction temperature instead of flame temperature. However, many sources of potential industrial heat are not sufficiently high to serve many applications (see figure 1). For example, the heat generated by conventional nuclear reactors is too low for most industrial processes. Similarly, combustion of wood pellets is insufficient for high-temperature industrial applications like steel, glass, and cement production.



Heat flux requirement: A second requirement of the heat source, related to the temperature requirement, is the heat flux. High heat demands and high throughput rapidly remove heat from the industrial system and must be met with high (and commonly continuous) heat flux into the system. The flux must be large enough to sustain reasonable production at a rate sufficient to maintain efficient production.

Figure 1: Temperature requirement of selected industries and temperature available for replacement of low-carbon heat source options



Sources: See Appendix B.

To replace heat supplies within an existing plant's design, the restrictions and limitations on reactors are strict, in part because of the physical geometry of reactors. For example, the volume of a cement kiln is very large and heated internally by solid fuels; applying heating options to the external surface (e.g., resistance electrical heating) would be difficult to heat uniformly throughout the reactor. Such constraints limit options for certain classes of heat production and deposition (e.g., electrical resistance heating). Where alternative heat supplies



are inherently intermittent (e.g., solar thermal concentration), operational demands require thermal storage (e.g., in molten salt systems). If electric power supplies are intermittent (e.g., onshore wind), bulk power storage systems or zero-carbon firm power options are needed. If heat energy sources have low energy densities (e.g., biomass), large land areas are needed and must be paired with systems that concentrate heat for industrial delivery.

Viability

Many existing industrial assets will continue to have long capital lives and operate for many years (and in some cases, decades), especially in developing Asia. Typical capital stock turnover for major equipment is 20–50 years. To effectively substitute alternative heat supplies, asset operators must be able to implement a viable substitution in existing facilities with sources of sufficiently high temperatures and flux. To be viable, options should involve minimal redesign or capital expense to a facility. Though some substitutions would be relatively straightforward and noninvasive (e.g., swapping burner tips for boilers and furnaces), substantially modifying existing reactors would be less viable (e.g., solid fuels with gaseous ones).¹⁵

Determination of viability is somewhat subjective. Key considerations would include mass transfer limits, requirements of working fluids (e.g., air, steam), physical space requirements and limits, degree of required modification, and cost. While physical and chemical limits are most relevant, economic considerations (e.g., up-front capital requirements, production derating) will prove critical. The nature of industrial plant operations and market dynamics may ultimately disqualify some options.



THE DIFFICULT NATURE OF INDUSTRIAL MARKETS AND POLICIES

Unlike power markets, where all product generated is consumed within the balancing authority of regional markets, industrial markets span the globe—steel, fuel, and chemicals are globally traded commodities. For this reason, a risk facing industrial decarbonization is carbon leakage, wherein industrial production is displaced from one nation to another (along with any attendant environmental emission or impact). This is accentuated by the fact that the margins for many of these industries are very thin—sometimes even negative.¹⁶ As such, a central business priority in industrial production is to maintain very low-cost supply chains, including operating facilities in locations with low energy costs, labor costs, and sometimes minimal burdens for environmental protections.

In addition, high capacity factors and maximum uptime are essential features of industrial production, which affects their heat and energy demands. Many industrial facilities suffer large revenue losses during the shutdown. For example, the estimated cost of downtime for an average US refinery is between \$0.34 and \$1.7 million per day.¹⁷ Capital investments are often extremely costly in such facilities, requiring tens and hundreds of millions of dollars for key pieces of equipment and 15–20 years of operation to recoup the investment. As such, many companies are reluctant to make investments in emerging technologies because of the attendant operational and commercial risks.¹⁸ Even when industry considers investments in heavy manufacturing facilities, stocks overturn very slowly. The capital life for many heavy industrial facilities is decades, even for relatively old plants such as cement kilns, refineries, or steel blast furnaces. In the United States, core equipment like kilns or blast furnaces are 50–60 years old yet show no signs of near-term replacement. In developing countries, many of these facilities are less than 10 years old and will not require major upgrades or replacement for decades. Recent studies suggest that these kinds of facilities worldwide will emit more CO₂ than is allowable under most 1.5°C scenarios assuming a natural capital life (i.e., without premature replacement).¹⁹ Ultimately, few industrial facilities show signs of imminent closure, especially in developing countries, making deployment of replacement facilities and technologies problematic.

Finally, many of these industries are considered a component of national pride and security. While this is particularly true of steelmaking,²⁰ much heavy industrial manufacturing is a source of pride or tied to iconic industries such as construction or the automobile sector. In most countries within the Organization for Economic Cooperation and Development (OECD), organized labor provides the key staff for many heavy industrial facilities (e.g., United Steelworkers). As such, their continued operation is a labor and political priority. Even if the risks or costs to a specific industry appear modest, many decision makers will treat them as politically essential. As one indication, most cement, steel, aluminum, and petrochemicals have received environmental waivers or been politically exempted from carbon limits, even in countries with stringent carbon targets.²¹

Accentuating these issues is the simple fact that most people do not buy raw industrial products like cement or methanol. The overwhelming majority of these products are



purchased by governments or corporations, not consumers (unlike, say, electric vehicles or LED light bulbs). This has resulted in little public or political focus on industrial sectors as well as an overall lack of familiarity with their operations and needs. This suggests that public preferences will have little direct impact on managing industrial emissions.²²

Ultimately, these factors present challenges to deploying low-carbon heat into new or operating industrial facilities. However, it may prove that since governments procure large volumes of these materials, they may be able to more directly affect markets through policy actions the public would not see.



BACKGROUND AND DATA

Literature about industrial heat and alternative supplies is scarce. Substantial research and data exist for energy broadly, including power generation and carbon management, but little summary data and analysis are available for heat supplies and their alternatives. In addition, many options for low-carbon heat are still in the early stages of development and commercialization, so robust market data don't exist. The difficulty of data collection reveals an important fact: Industrial heat options remain understudied and require further scholarship. To provide estimates for heat quality and costs of production, the authors generated cost data for each option from a wide array of literature and government data sets. The specifics for individual cases and methodologies are largely found in Appendix A.

In most cases, data conversion is required as the original data are in varied units (e.g., dollars per kilogram [\$/kg] for hydrogen, biomass, and biodiesel versus dollars per kilowatt hour [\$/kWh] for electricity versus dollars per one million British thermal units [\$/MMBTU] for gas). The authors converted these data to the equivalent heat value, in some cases assuming some thermodynamic losses associated with conversion to heat. The authors' reference unit is dollars per gigajoule (\$/GJ)—a unit not used currently in market exchanges or most commercial standards—to anchor comparative analysis.

For each industry (steel, glass, ammonia, etc.), the heat quality requirement is obtained from industry specifications, either in GJ (heat/energy) or GJ/hr (heat power). The authors gathered data from specific industry reports, often representing global or national averages. Some academic papers contain process details specific for an individual plant but used as representative (cement clinker and methanol). For plants' specific data, representative processes are explained and presented as well. The authors recognize that this makes apples-to-apples comparisons difficult and may introduce some inaccuracies into the authors' calculations.

To better represent the authors' analysis, additional terms and units proved important:

- *Temperature*: The temperature is set to be the maximum temperature needed for the whole process analyzed if the industry identified more than one heat inputs process.²³
- *Energy density*: GJ/ton, the heat required for producing one unit (ton) of product.
- *Heat-related carbon density*: ton/ton (carbon emission per unit of product). This measures how carbon intensive this industry is in terms of heat input.
- *Total carbon density*: ton/ton (carbon emission per unit of production). This measures how carbon intensive this industry is, including both heat input and other associated emissions (e.g., byproduct chemical emissions).

To simplify the authors' assessments, the authors assume that the replacement heat option supplies heat perfectly to the existing system—that is, it has 100 percent efficiency for



replacement—to calculate the specific costs resulting from substitution. For this study, the authors ignored the efficiency change associated with providing alternative heat sources. For example, to produce cement clinker, the primary heat requirement is 3.444 GJ/ton production of clinker using coal. Replacing coal with hydrogen may ultimately require more or less actual heat as a function of detailed facility requirements, but without additional engineering data or constraints, the authors left the primary heat requirements the same.

Estimating costs proved more challenging still. In many cases, the key technologies do not exist at commercial scale (e.g., advanced nuclear reactor systems) and cannot be readily priced. For these systems, the authors relied on published estimates from academic researchers, understanding that they are projections. In other cases, component systems exist at commercial scale, but integrated systems are not yet commercial (e.g., renewable hydrogen production, some industrial post-combustion capture systems). These systems commonly were characterized by standard engineering cost estimates but without full financial estimates (e.g., cost of capital, time for construction, contingency). Here, the authors relied on a combination of empirical data from the commercial components (e.g., existing nuclear plants, hydrogen from steam methane reforming [SMR]) and extrapolations to commercial systems. Alternatively, academic estimates provided the best full system accounting. In some cases, these estimates were projections into the near future (e.g., 2025); however, the authors did not use far future projected cost or assume future cost reductions because of learning by doing or assumed learning rate.

Current and future policy options could potentially change the price point for various technology options. For example, the amended 45Q tax credits in the United States²⁴ could reduce the cost of products delivered with hydrogen from natural gas plus CCUS. Alternatively, the revised European Trading Scheme market could provide some financial returns or avoided costs through market exchanges. In this study, the authors focused exclusively on *cost*. Future studies will assess the potential for policy to affect the *price* of industrial products made with low-carbon heat supplies.

In considering what to explore, the authors selected to defer many topics for future work (see “Future Work” section). These included questions around the potential for technologies to improve (cost, performance, efficiency, etc.), the potential for system optimization or hybrid approaches (e.g., combined heat and power), representation of the cost of raw materials versus the embodied costs in finished products (e.g., cars, bridges), or technologies that are extremely immature (e.g., hydrogen production using the iodine-sulfur cycle). These topics merit additional attention and could constitute the basis for expanded programs on the topic of industrial heat decarbonization, some of which are discussed in that section.



OPTIONS FOR LOW-CARBON HEAT

Few options are capable of providing low-carbon heat at the quality and flux required to operate commercial industrial facilities. Given the limited options for heat substitution, the authors selected a set of options that appeared sufficient, potentially viable, and broadly applicable. These sources are derived from complex operations and systems that place constraints on their potential (e.g., gathering biomass feedstocks). Details on the options can be found in Appendix A.

Hydrogen Combustion

Hydrogen is the most abundant element in the universe and is extremely abundant on earth, usually bound to other elements as compounds (e.g., methane, water). Producing hydrogen requires separating it from other elements chemically, electrically, or thermally.

Hydrogen can serve as the reduction agent or reactant (e.g., for steelmaking and oil refineries) and other energy applications (e.g., electric production via fuel cell). For low-carbon heat applications, the authors considered only direct combustion for heat generation. Additional analyses such as detailed process engineering requires additional study (see “Future Work” section).

The most widely used hydrogen production technology today, in particular in OECD countries, is natural gas reforming, most commonly SMR. It is mature, relatively cost effective, and energy efficient and can operate wherever natural gas supplies exist. In production, high-temperature steam (700–1,000°C) is mixed with methane, usually in the presence of a catalyst. Related approaches involve gasification of fossil feedstocks (e.g., coal, bitumen) with the addition of a water gas shift reaction, which produces extra hydrogen and consumes extra heat and water. Gasification with water-gas shift is common in economies that lack natural gas supplies (e.g., China, India, South Africa).²⁵ In the United States, 95 percent of the hydrogen is produced by natural gas reforming in large central plants.²⁶

Hydrogen is not a GHG, and its combustion emits only water. However, production of hydrogen commonly results in byproduct GHG emissions, since it is usually derived from hydrocarbons. These are consequences of the core reforming chemistry and also from fossil fuel combustion, since SMRs, gasification, and water-gas shift processes require large amounts of heat to operate.²⁷ The values and ratios of these emissions are presented in Appendix A and are a product of both heat associated with gas reforming and the process chemistry, which results in high-concentration byproduct CO₂.

A completely different option for hydrogen production is electrolysis of water. Electrolysis uses electricity to break down water into hydrogen and oxygen using an electrolytic cell. Both the electric power used and the capital costs of electrolyzers are major cost elements. Here, there is no byproduct GHG production, so if the power supply is low carbon (e.g., solar, nuclear) then so is the hydrogen produced. An attractive option, now widely discussed, is to use excessive electricity production (curtailed generation) to generate hydrogen by



electrolysis.²⁸ A somewhat similar emerging approach, photoelectrochemical (PEC) water splitting, directly separates water molecules into hydrogen and oxygen using photonic energy (light) instead of electrical energy.

For the purposes of this report, the authors classify hydrogen for decarbonized heat as either gray, blue, or green based on carbon footprint and production method:

- *Gray hydrogen* is made from gas reforming without carbon controls. Production of gray hydrogen would release CO₂ from both byproduct chemistry and combustion. The carbon footprint of gray hydrogen is somewhat worse than that of methane and would not qualify as a low-carbon heat option.
- *Blue hydrogen* is also produced from gas reforming but *with* carbon controls. If byproduct CO₂ from the SMR unit is captured and stored, the net carbon footprint is reduced about 55 percent. Three plants around the world do this today,²⁹ and the technology and processes are well established. If an operator also captured CO₂ from the facility's remaining operations, the net carbon footprint could be reduced over 90 percent, effectively CO₂ neutral.³⁰ Blue hydrogen is considered an option for low-carbon heat but is only viable in geographies where CCUS can be deployed (e.g., where there are geological storage sites) and only provided there are minimal associated upstream emissions.
- *Green hydrogen* is produced from water by electrolysis from near-zero electricity sources such as hydropower, solar, nuclear, and wind. Grid-based electrolysis in most economies (e.g., the United States) would have a substantial associated carbon footprint and would not be considered a low-carbon heat option. To serve most industrial heat systems, hydrogen supply must be constant. This requires that intermittent electricity sources must be firmed by batteries, grid operations, and others, which may add costs or add life-cycle carbon emissions (or both).

Since this report focuses on options for decarbonized heat, the authors assess only blue and green hydrogen as options but use gray hydrogen as a basis for comparison with today's approaches and costs.³¹

Biomass and Biofuels

Biomass (woody, cellulosic, and vegetable fat) converted to fuel or used and combustion feedstocks could potentially provide low-carbon heat. Today's biomass and biofuel industries are mature, including biodiesel, ethanol, and biomass power generation,³² and large biomass markets exist both in OECD countries and some developing countries (e.g., Brazil). Biomass is dispatchable and can be transported to facilities from distant locations. To ease feed and transport, it is often pelletized.

Almost 90 percent of biomass is used for heating, burned directly in various applications. The remainder is used as feedstocks and raw materials. Current biomass consumed in the United States is roughly 42 percent wood and wood wastes, 48 percent biofuels (including both ethanol and biodiesels), and 10 percent garbage/landfill wastes.³³ The direct combustion of



biomass for power generation is a relatively mature technology, where biomass combustion boils water for a steam turbine.

In general, biomass and biofuels are considered low-carbon feedstocks, and when combined with CCUS, could remove CO₂.³⁴ However, the specific carbon footprint of any biofuel can vary greatly as a function of climate, agricultural practice, harvest radius (transport distance), regrowth rate, conversion, transportation distance and method, and macroeconomic displacement effects (i.e., carbon leakage).³⁵ This is discussed in greater depth below and in the “Life-Cycle Assessment Concerns” section.

For the purposes of this report, the authors consider direct combustion of biomass feedstocks as one form of heat generation and assume complete combustion (i.e., 100 percent thermal efficiency). The authors use pelletized wood supply in part because it is well understood and in broad commercial use. The authors also consider biodiesel, ethanol, and biogas fuels, which have the advantages of high energy density, ease of transport, and simplicity of use in many industrial settings. For example, methane derived from biogas could readily substitute for natural gas, and many commercial systems (e.g., atomizers, carburetors) allow liquid biofuels to substitute for gaseous feedstocks. For this study, the authors use biodiesel as a representative source of potential low-carbon heat.

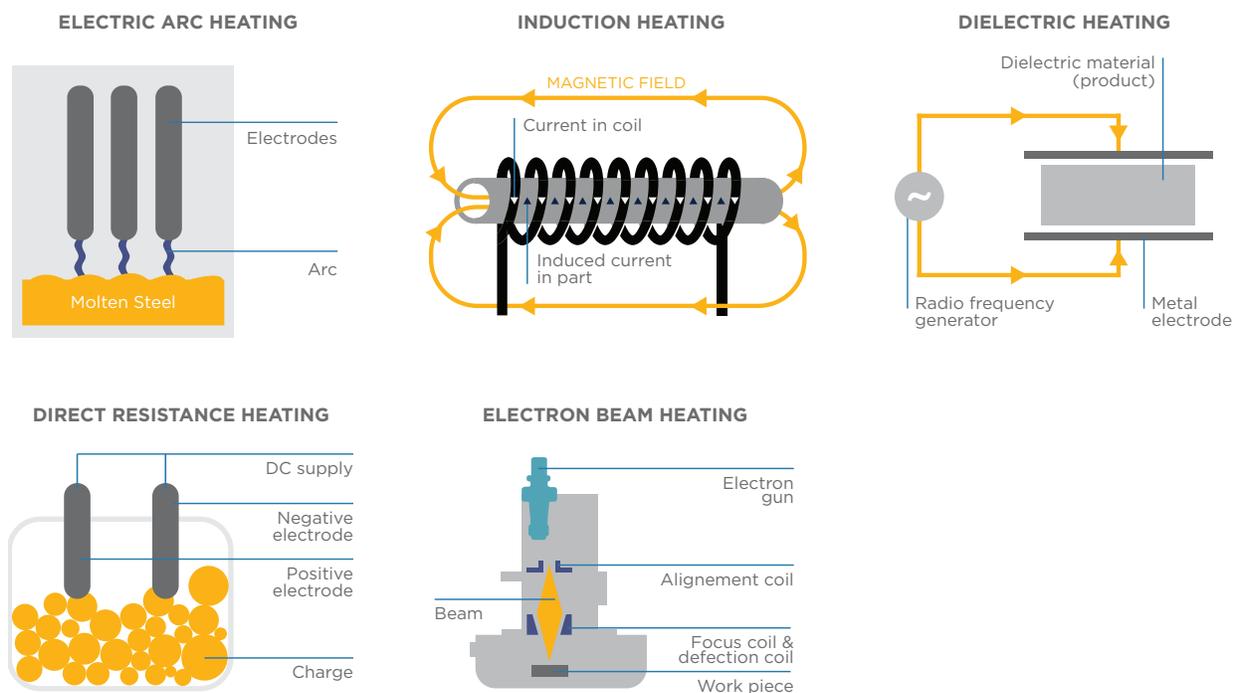
Electricity

Electrification of heating describes a wide set of processes that can be used for multiple purposes: drying, curing, melting, and transformation of products.³⁶ All electrification technologies use electricity as a feedstock and specifically designed systems to generate and transmit heat. Typically, electric-based process heat can be categorized into two categories, depending on whether heat is generated within the material (i.e., the heating target):

1. *Direct heating*: heat generated within the material (e.g., electric current passing through the heated material and working as a resistive heater, or inducing eddy currents into the material)
2. *Indirect heating*: heat generated externally and transferred to the material via conduction, convection, or radiation (e.g. microwave heating of water and then using steam heating).



Figure 2: Representative heating processes using electricity³⁷



Direct heating can bypass the heat transfer process and therefore achieve potentially higher efficiency, reducing the loss from heat transfer. In general, the materials’ intrinsic properties provide the biggest constraints: it either must be conductive (current can pass through and form closed circuit) or it can absorb certain electromagnetic frequencies. Depending on the material to be heated, direct heating may not be feasible, as it depends on the material property (see Appendix A).

Practically, few substances are well suited for direct heating, so indirect approaches are more common (see figure 2). Electric arc furnaces are one widely used industrial approach that use indirect electric heating to recycle steel. During indirect heating, heat or electromagnetic energy is generated externally and then transferred to materials to be heated. The primary limitation is the quality of heat (temperature and flux) and the ability to transfer heat across the reactor in question (e.g., across a kiln or blast furnace). Secondary limitations are often associated with the specific application and its requirements (e.g., vapor-phase heating or complex heat management requirements).

Resistive heating is one of the most common approaches, and recent research has pushed the temperature limit to over 1,800°C.³⁸ This is sufficiently hot for most industrial processes. The authors used electric resistance heating as a representative for indirect heating as one of the electrification pathways. The efficiency of converting electricity to heat is 100 percent for resistance heating.³⁹ The heat flux limitation depends on engineering design details. An example calculation is performed for the cement kiln application in Appendix B.



The carbon footprint of electricity can vary widely, and electrification alone does not necessarily produce low-carbon heat. The carbon footprint of power generation is dependent on many factors, including the fuel, efficiency of conversion, and technology choice to balance intermittent generation (see “Life-Cycle Assessment Concerns”). As low-carbon sources of electric power gain market share and prominence (e.g., solar, wind, geothermal, hydro, and nuclear), electrification has the potential to provide low-carbon heat to many industrial systems. Depending on the engineering details, it could provide other advantages: higher energy efficiency, shorter processing time, better quality control (e.g., less impurity from combustion), better flexibility for smaller and modular plants design, less warm-up time, and less capital cost.⁴⁰ These possible benefits were not considered in these analyses.

Nuclear Power

Nuclear power is the dominant source of low-carbon energy in the world and provides a large fraction of low-carbon power in many large economies, including the United States, Canada, France, Sweden, and India. Almost all of this power comes from converting nuclear heat to run a steam turbine. As such, nuclear power produces the largest volume of low-carbon heat available today worldwide. This has led many to consider direct use of nuclear heat as a potential supply for industrial applications.⁴¹ However, because of many issues, including collocation of resources, safety, and proliferation concerns, no existing facilities today use nuclear reactor heat directly in industrial production.

In considering potential applications, the nuclear reactor design and operation places substantial limits on viability and overall potential utility. It is common to refer to most reactors as *conventional and advanced* designs.

Conventional nuclear: Conventional reactors generate heat from radioactive decay that produces steam, commonly referred to as generation II and III systems.⁴² These reactors and associated systems are mature and widely deployed. In considering how to harvest heat from conventional nuclear reactors, the authors focus on a simple retrofit of existing reactors without significant design variation.

The United States is the largest producer of nuclear power, generating about 30 percent of the world’s total nuclear electricity for roughly 20 percent of its total electrical power supply. Out of 98 operating power reactors in the United States, 65 are pressurized water reactors (PWR) and 33 are boiling water reactors (BWR). Almost all reactors were built between 1967 and 1990.⁴³ The authors focus on the two predominant generation III reactor designs, given their deployment potential, strong safety record, and longer years remaining.

1. BWR—Water acts as a coolant and directly absorbs reactor core heat to produce steam, which rotates the turbine engine.⁴⁴
2. PWR—A coolant (first loop) absorbs the heat generated by the core and transfers the heat to the steam generator (secondary loop), evaporating the water in the secondary circuit in a steam generator to power the turbine.⁴⁵ Here, only the first loop absorbs nuclear heat directly.

Table 2 summarizes the temperature available and the heat medium for generation III reactors.



Table 2: Generation III nuclear reactors

Reactor type	Temperature available (°C)	Coolant (heat medium)
BWR	About 300	Steam
PWR	About 315	Steam

Sources: BWR: Nuclear tourist, <http://www.nucleartourist.com/type/bwr.htm>; PWR: Wikipedia, https://en.wikipedia.org/wiki/Pressurized_water_reactor.

Importantly, neither the BWR nor PWR produce high-temperature heat or steam. This greatly limits their range for current industrial process applications. In addition, very few of these reactors are close to existing industrial facilities, which limits their viability as retrofit heat options.

In addition to these two designs, the authors consider fast breeder reactors (FBR) to be conventional designs that could provide heat. FBRs belong to the class of fast neutron reactors (FNR). Compared to other nuclear reactors that use water for coolant, FBR deliberately uses coolant that is insufficiently efficient, such as liquid sodium, to provide high-energy neutrons, which generate new isotopes that can be reprocessed to produce more reactor fuel. Two experimental FBRs were built in the United States, but neither reactor produced electricity commercially because of safety concerns.⁴⁶ Sufficient data exist to estimate their costs for heat supply, but the authors do not expect these systems to enter deployment so do not provide their analysis for context and comparison. More advanced versions of these reactors are considered as one option for potential low-carbon heat.

Advanced nuclear: This refers to reactors that are still in the design and research stage and not yet commercially available, commonly referred to as generation IV reactors.⁴⁷ Of the six types of generation IV reactor technologies (see table 3), four are FNRs. All generation IV reactors operate at higher temperatures than today’s reactors, providing a bigger potential range for industrial applications. Four types are designated for potential hydrogen production using the iodine-sulfur cycle (see Appendix A for details about nuclear hydrogen production).



Table 3: Generation IV nuclear reactors

Reactor type	Neutron spectrum (fast/thermal)	Coolant	Temperature (°C)	Application*
Gas-cooled fast reactor	Fast	Helium	850	Electricity/hydrogen
Lead-cooled fast reactor	Fast	Lead or Pb-Bi	480 to about 570	Electricity/hydrogen
Molten salt reactor	Fast/thermal	Fluoride salts	700 to about 800 (fast), 750 to about 1,000 (thermal)	Electricity/hydrogen
Sodium-cooled fast reactor	Fast	Sodium	500 to about 550	Electricity
Supercritical water-cooled reactor	Fast/thermal	Water	510 to about 625	Electricity
Very high-temperature gas reactor	Thermal	Helium	900 to about 1,000	Electricity/hydrogen

*Application including hydrogen generation is potentially available for industrial process heat, but is not included in this table.

Gas-cooled fast reactor, lead-cooled fast reactor, molten salt reactor, and very high-temperature gas reactor types are designed to operate in a higher temperature range. To simplify the authors' analysis, the authors selected 850°C as a representative generation IV temperature for discussion in this paper.

Small modular reactors: Plants composed of sets of small power generation modules are receiving increased attention and development, in part because of their lower unit capital costs and reduced physical footprint.⁴⁸ Small modular reactors are defined as typically 300 MWe equivalent or less. Most modular designs are expected to have greater design simplicity with reduced costs from factory production and short construction times and risks. The temperature ranges from 300 to about 850°C, enough to support ammonia production, methanol synthesis, SMR for hydrogen production, and supercritical steam for turbines and petrochemical reactions. The development of small modular reactors spans all types of reactors: light-water reactors, high-temperature gas reactors, liquid metal reactors, molten salt reactors, and so on. The heat output from small modular reactors is typically assumed to be 100 to about 600 MW thermal, suitable for many industrial applications.

In 2009, the International Atomic Energy Agency estimated that by 2030, 43–96 small nuclear power reactors will be put into operation worldwide—but expect no small nuclear power reactors in the United States.⁴⁹ This would be a rather small capacity for electricity generation: a maximum 30 GW capacity considering 300 MWe per plant. For electricity generation capacity, this is a trivial part of power generation capacity, only equivalent to the New York state power capacity (about 40 GW). Substantial effort is put into the other applications of small modular reactors—for example, industrial applications.



Biogas and Power2Gas

Today, many industrial systems operate on heat from natural gas combustion. This is especially true for refineries and petrochemical/ammonia plants, which use natural gas as a feedstock. If zero-net carbon natural gas was widely available, it would address an enormous fraction of the potential market for low-carbon industrial heat. This has led some to conclude that “renewable” gas, including biogas and gas produced by electrocatalytic upgrading of CO₂ (Power to Gas), is an essential component of the future energy mix.⁵⁰

Biogas is the gaseous product from the anaerobic digestion process of biodegradable materials, typically organic waste and garbage. The composition of typical biogas is 50–70 percent methane and 30–50 percent carbon dioxide, with a small fraction of other contaminants. Various waste sources can be used for biogas production: landfill materials, wastewater, animal manure, and other organic wastes.

Biogas can be directly burned to provide heat and electricity or upgraded to pure methane (biomethane), which has the same energy content as natural gas. The US resource of biomethane in 2013 could provide the equivalent of 5 percent of natural gas consumption in the electric power sector.⁵¹

Using biomethane has dual effects for GHG mitigation: it can reduce the methane leakage to the atmosphere while providing a low-carbon energy source to replace conventional natural gas consumption. Avoided methane emissions from sources like dairy operations or landfills commonly qualify as associated emissions reductions as well, as methane is a very potent GHG.⁵²

Another pathway to provide renewable natural gas is called Power to Gas (also referred to as Power2Gas or P2G). It can refer to both Power2Hydrogen and Power2Methane. Here the authors focus on Power2Methane specifically.

Figure 3: Power2Gas concepts: Power2Hydrogen and Power2Methane⁵³



The most common process combines electrolysis for hydrogen and methanation—the synthetic conversion of hydrogen and carbon dioxide into methane (see figure 3). It uses both electricity and carbon dioxide with byproduct water. One Power2Gas project in Rozenburg, Netherlands, is a representative pilot project of the Power2Gas concept, and the produced methane was successfully upgraded to natural gas quality for use in a gas-fired boiler. Several recent reports⁵⁴ identify renewable natural gas, both from biogas and Power2Gas, as important pathways to deep decarbonization, including for heavy industrial applications. Biogas has the appeal of avoided methane emissions, low cost for use, and direct substitution for regular natural gas supplies. The Power2Gas concept could provide low-carbon hydrogen



as well as methane from renewable electricity, potentially serving as a low-carbon heat source in the future. Unfortunately, both approaches face substantial limitations to deployment today.

The largest barrier to biogas is the ability to scale. Most biogas comes from landfills, which are geographically and resource limited. In Germany, the Energiewende supported waste biomass gasification and methanation but was able to support only a small fraction of the power system (and none for heavy industry).⁵⁵ The Netherlands and the UK have supported biogas through a substantial feed-in tariff of 45 to about 95 EUR/MWh for landfill and 69 to about 125 EUR/MWh for anaerobic digestion plants,⁵⁶ but they are still unable to fill the demand.

Regarding Power2Gas, the technology remains immature and costly—even with low-cost renewable power, costs are estimated to be \$12–\$30/MMBtu.⁵⁷ Current systems are mostly bench scale.⁵⁸ There are a few pilot systems (e.g., the Sunfire project in Italy), but challenges remain regarding longevity, corrosion, selectivity of electrocatalytic reactions, and overpotential requirements. Lower operating and capital costs and higher system efficiency are necessary to make Power2Gas costs competitive.

Solar Thermal

For the purpose of industrial heat, only concentrated solar power (CSP) can provide possibly high enough temperature for most industrial processes. CSP's working principle is to reflect and concentrate solar radiation onto a small area to increase temperature and power yields. Typical projects provide about 100 MWe from a single unit (e.g., Ivanpah).⁵⁹ Project costs have exceeded \$1 billion and occupy more than 10 km² of land. One advantage solar concentrating systems have is the potential to store thermal energy—for example, in molten salt. The Copiapo project in Chile is scheduled for completion in late 2019 and has 13 hours of molten salt thermal storage. Although expensive (total costs are roughly \$2 billion), the bidding price on electricity contracts without subsidies is lower than \$0.05/kWh.⁶⁰

Land use requirements limit the viability of solar thermal for industrial applications. Solar thermal heat for 100 to about 300 MW heat flux would occupy 3,000–8,000 acres (12 to about 30 km²) of land, comparable to a typical steel plant layout (3,000 acres) and 10–40 times more than an equivalent fossil-powered thermal station (200 acres).

Various kinds of solar concentration technologies are available, providing a wide range of heating:⁶¹

- *Parabolic trough*: 260 to about 400°C
- *Parabolic dish*: 500 to about 1,200°C
- *Power tower*: 600 to about 1,000°C
- *Linear Fresnel*: 260 to about 400°C

To build CSP with high enough power and temperature, a large flat surface of land with ideal solar radiation (i.e., low latitude and dry climate) is required, limiting CSP by geographic reach (typically deserts). These regions typically lack existing infrastructure (roads, pipelines,



transmission lines) and heavy industry facilities today.

To provide heat supply after sunset, molten salt thermal storage is also required. Molten salt's maximum working temperature of 560°C defines the upper practical limit for industrial use.⁶² Next-generation molten-salt technology must exceed 800°C for many industrial applications. Even when thermal storage is available, the reliability of CSP would be hampered by seasonal variation. The CSP is operating with essentially zero operating cost and can keep producing value for 30-plus years if designed and operated properly. Fuel costs are effectively zero for CSP and the CSP levelized cost of electricity (LCOE) systems' costs have continued to drop, suggesting possible future applications in low-medium temperature systems (e.g., petrochemicals), provided such facilities are located in appropriate solar resource geographies.



GENERIC COST ESTIMATION: ANALYSIS AND COMPARISON

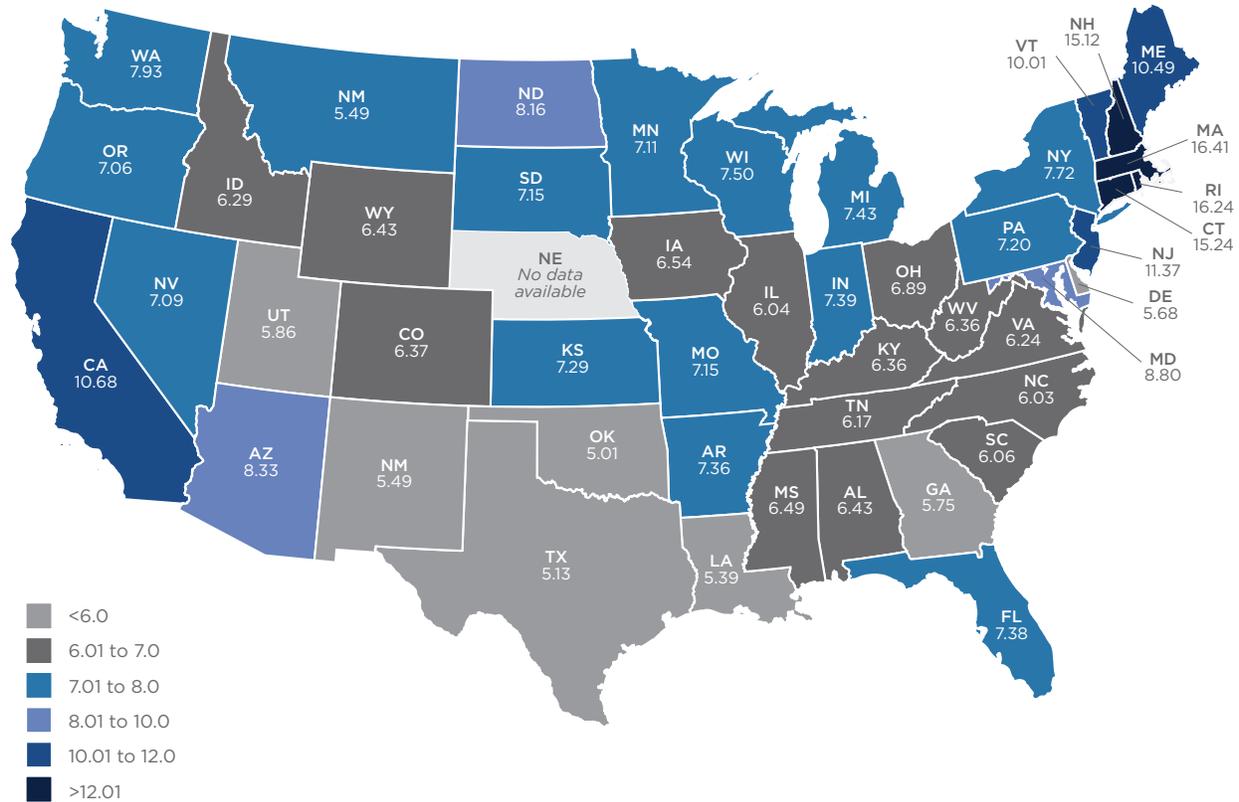
Industrial heat is not a commodity. It is not commonly bought, sold, or traded (unlike power or fuel) and doesn't enter most people's immediate experience. This presents a problem in description and standardization. Fuels are traded as volumes (gallons, standard cubic feet) or masses (tons, kilograms). Electricity is sold as power over time (MWh). Industrial products are priced by unit sold, commonly by mass.

For this study, all costs are presented as \$/GJ. Where possible, the authors try to represent the likely effect on unit production costs. True costs of a potential substitution for industrial heat depend on an enormous number of variables. While future work will explore cost sensitivities, this report relies on a handful of assumptions and simplifications, which are detailed in Appendix A.

Because electric power is a substantial input to several important options (e.g., resistive heating, green hydrogen production), the cost of power is an important variable. Although some renewable power contracts and tariffs are extremely low and getting lower,⁶³ these are not representative of many industrial geographies, current contracts, or applications. To attempt to use power costs that are more representative of industrial applications, the authors used average costs for industrial power contracts, which represent both firm supplies and relatively low rates because of bulk power purchases (see figure 4). Based on US price data from the Edison Electric Institute and US Energy Information Administration, industrial power prices range from \$46.4–\$200.9/MWh, with a median price of \$69.2/MWh.⁶⁴



Figure 4: Total average industrial rates by state (cents per kilowatt-hour)

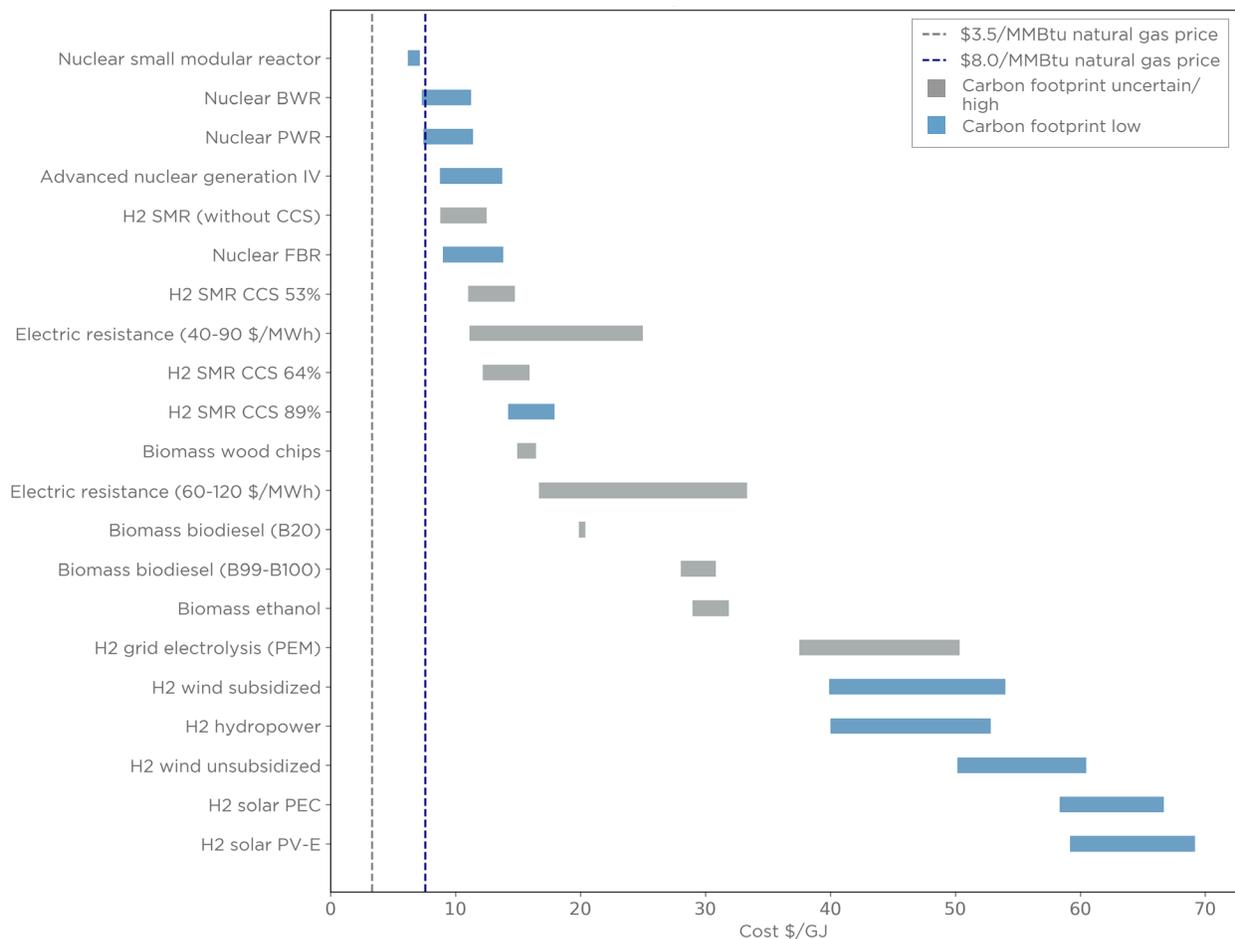


Note: Reflects total retail average rates for 12 months ending in June 2018.
 Source: Typical Bills and Average Rate Reports, Summer 2018, Edison Electric Institute

Using these and similar assumptions, each low-carbon heat option presents a range of associated costs (see figure 5). Specifics for different costs are provided with each distinct supply type below. The ranges for many supplies relate to the range of power costs and fuel costs and in some cases reflect subsidized versus unsubsidized prices. They also reflect variations in process type (e.g., different forms of radiant heating). For certain specific applications (e.g., renewable hydrogen production), the authors used the LCOE from Lazard 2018 as inputs.⁶⁵



Figure 5: Generic cost comparison summary for various options of heat



First and foremost, while figure 5 does present costs, it does not present the carbon footprint of different options. The fractional decarbonization for these options varies widely (e.g., hydrogen from SMR with/without CCUS, hydrogen electrolysis from grid electricity and renewable electricity). This is discussed further under the “Life-Cycle Assessment Concerns” section. The authors discuss their use and viability below under the “Considerations of Specific Industrial Applications” and “Considerations of Viability” sections. Figure 5 compares only the cost of delivery for all sources of heat applicable to industrial purposes.

Importantly, many cost estimate uncertainties are not included here. While some options have relatively stable costs (e.g., US-based hydrogen from SMR, biofuels), some have larger uncertainties (e.g., nuclear heating and hydrogen from renewable sources). In some cases, there is substantial variance in commodity cost (e.g., EU-based hydrogen from SMR). In other cases, the technology does not exist (e.g., advanced nuclear heating), the technology is immature (e.g., resistance heating), or no large-scale demonstration exists (e.g., wind/solar to



hydrogen). Generally, the authors focus on costs, but for biofuels/biomass and grid electricity, the authors use price instead. The actual heat price for industrial application payers will be different considering indirect costs and other factors.

Individual cost estimates and data are discussed below. Detailed discussions and tables that contributed to figure 5 can be found in Appendix B.

Hydrogen from SMR with CCUS (blue hydrogen)

The additional costs for CCUS varied as a function of capture fraction, which itself ties back to the parts of the SMR plant system where CCUS was applied. Collodi et al.⁶⁶ analyzes hydrogen production process, both without CCUS and for several different applications of CCUS, representing a CO₂ capture rate between 53 and 89 percent.⁶⁷ For all analyses, Collodi et al. developed a levelized cost of hydrogen (LCOH) that serves as a useful standard for comparison. For the estimates, the authors assumed a cost for natural gas of \$3.5/MMBtu (see table 4). This analysis suggests that adding CCUS to hydrogen production would add 20-50 percent to the production costs as a function of capture rate.

Table 4: Heat cost of hydrogen from SMR

SMR to H ₂	Capture rate	LCOH	Cost of heat (lower heating value [LHV])
SMR without CCUS	0	1.05-1.5 \$/kg	8.78-12.51 \$/GJ
SMR with CCUS	53%	1.32-1.77 \$/kg	11.02-14.75 \$/GJ
SMR with CCUS	64%	1.46-1.91 \$/kg	12.19-15.91 \$/GJ
SMR with CCUS	89%	1.71-2.15 \$/kg	14.22-17.92 \$/GJ

Sources: Global CCS Institute, US Energy Information Administration, Canada Energy Regulator, Praxair, and Progress in Energy and Combustion Science⁶⁸

Hydrogen from Renewable Energy

Hydrogen from Solar

Multiple methods are possible to produce hydrogen from solar energy. Shaner et al. compared three methods using grid-based electrolysis as a reference system:⁶⁹

- *PEC*: Direct splitting of water molecules using photonic energy in one integrated module
- *Photovoltaic-to-electrolysis (PV-E)*: Produces electricity via a photovoltaic cell that then drives an external electrolyzer to produce hydrogen
- *Grid electrolysis (proton exchange membrane [PEM])*: The electrolysis of water in a cell equipped with a solid polymer electrolyte using grid electricity, here presented as a comparison baseline



Estimated LCOH of the three methods of solar hydrogen production assumes full release of the calorific value of H₂ and does not include additional system or transmission costs or production losses associated with intermittency (see table 5). This estimate suggests that hydrogen produced from solar would add dramatic costs: a three- to five-factor increase compared to current SMR technology. Even grid electrolysis will result in a 100 percent increase of LCOH compared to conventional SMR production. These costs in part reflect the cost of utility-scale firm solar power. They do not reflect the low utilization rate of electrolyzers as a function of intermittent power delivery, which means real costs may prove higher still.

Table 5: Heat cost of hydrogen from solar

Hydrogen production	Electricity cost	Capacity factor	LCOH	Cost of heat (LHV)
SMR with CCUS (89%)	N/A	N/A	1.71–2.15 \$/kg	14.22–17.92 \$/GJ
Grid electrolysis (PEM)	60–90 \$/MWh	90%	4.50–6.04 \$/kg	37.52–50.34 \$/GJ
Solar PV-E	36–46 \$/MWh	20%	7.1–8.3 \$/kg	59.2–69.2 \$/GJ
Solar PEC	N/A	20%	7.0–8.0 \$/kg	58.4–66.7 \$/GJ

Sources: *Energy & Environmental Science*

Hydrogen from Wind

To estimate LCOH for wind-based electrolytic production, the authors take the LCOE of wind power and assume efficient electrolysis. This approach internalizes capital costs, nameplate capacity, cost of capital, and capacity factors in estimating LCOE.⁷⁰ Because LCOE for wind generation varies across the United States, the authors used Lazard 2018's range of values.⁷¹

Using the same water electrolysis assumptions, the wind-to-hydrogen cost can be derived according to its capacity factor and assuming 100 percent combustion (see table 6) and does not account for trade-offs of wind resource geography versus industrial siting, transmission limitations, or production losses from intermittency.

Table 6: Heat cost of hydrogen from wind

Hydrogen production	Electricity cost	Capacity factor	LCOH	Cost of heat (LHV)
Grid electrolysis (PEM)	60–90 \$/MWh	90%	4.50–6.04 \$/kg	37.52–50.34 \$/GJ
Wind subsidized	14–47 \$/MWh	35%	4.79–6.48 \$/kg	39.91–54.02 \$/GJ
Wind unsubsidized	29–56 \$/MWh	35%	6.02–7.25 \$/kg	50.17–60.46 \$/GJ

Sources: LCOE: Lazard;⁷² LCOH: Shaner et al.⁷³



With roughly the same LCOE of electricity, wind to hydrogen is cheaper than solar to hydrogen, mainly because of a higher assumed capacity factor. The actual cost may be higher considering intermittency and other limitations (like congestion charges or long-term maintenance issues).

Hydrogen from Hydroelectric Power

Hydroelectric power is the most abundant low-carbon power source worldwide, in part because it is fully dispatchable and has low capital and operating costs.⁷⁴ This makes it both the lowest-cost renewable power overall and able to provide 24/7 reliable power ideal for industrial applications. Perhaps unsurprisingly, countries with abundant hydropower are among the first to explore electrolytic hydrogen production (e.g., Sweden’s recent announcement for a zero-emission steel plant).⁷⁵

One estimate of hydrogen production cost of \$5.5/kg⁷⁶ assumes a hydroelectric LCOH. Assuming 100 percent combustion efficiency, the heat cost for H₂ produced from hydroelectric power is \$45.83/GJ. This estimate lies within the range the authors estimate for LCOH (see table 7), which assumes existing hydropower generation (i.e., no new hydropower construction) and electrolysis of hydrogen on site.

Table 7: Heat cost of hydrogen from hydroelectric power

Hydrogen production	Electricity cost	Capacity factor	LCOH	Cost of heat (LHV)
Grid electrolysis (PEM)	60–90 \$/MWh	90%	4.50–6.04 \$/kg	37.52–50.34 \$/GJ
Hydro to H ₂	30–60 \$/MWh	40%	4.80–6.34\$/kg	40.01–52.83 \$/GJ

Sources: LCOE: US Department of Energy, US Energy Information Administration;⁷⁷ LCOH: Shaner et al.⁷⁸

Hydrogen Summary

Looking across hydrogen generation options (see figure 6), conventional production from natural gas without CCUS (gray hydrogen) remains the cheapest option. It also appears that the option of partial or full capture on a CCUS facility (blue hydrogen) is cheaper than current options for hydrolysis with renewable power (green hydrogen), including hydropower and onshore wind and with very similar carbon footprints. More complete and comprehensive comparisons can be found in table A.1.1 in Appendix A.

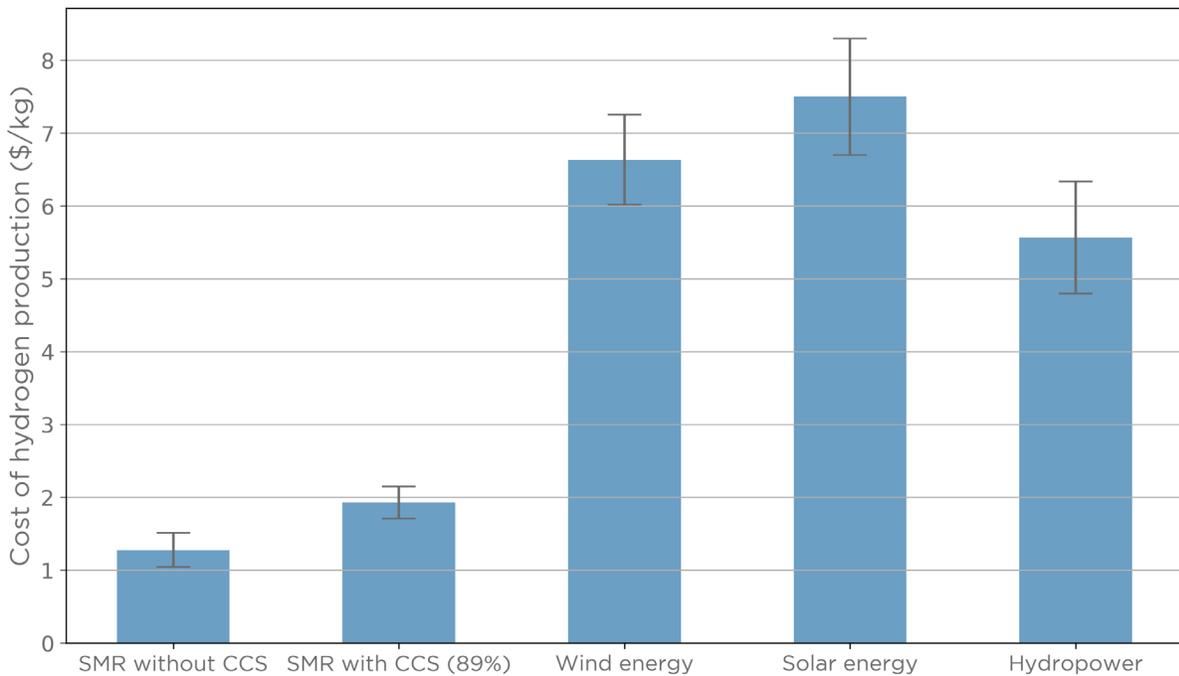
LCOH costs using wind and solar may continue to come down in price, mainly because of the expected drop of LCOE for both wind and solar.⁷⁹ Hydropower to hydrogen should remain the same and is not expected to drop, except for the capital cost of the electrolysis system.

For grid electrolysis of hydrogen production, reaching the same cost level of SMR with 89 percent CCUS is extremely challenging. The National Renewable Energy Laboratory’s analysis shows that at a 90 percent capacity factor for renewable generation, to produce hydrogen at less than \$3/kg requires electricity cost much lower than \$30/MWh.⁸⁰ IRENA’s



projection of 2025 shows a similar result.⁸¹ The authors estimate that hydrogen electrolysis could be cost competitive with hydrogen SMR plus 89 percent CCUS if power prices were \$7-\$15/MWh electricity and with a 90 percent capacity factor. If capacity factors were much lower, specifically 35 percent, hydrogen from electrolysis cannot be cost competitive (at a 35 percent capacity factor, electricity costs would need to be \$0-8/MWh—effectively free). Similarly, if capital cost (i.e., costs of electrolyzers) were to drop by 50 percent, hydrogen from renewable electrolysis would reach the SMR plus 89 percent CCUS assuming \$20-\$30/MWh and 90 percent capacity factor.

Figure 6: Cost of hydrogen production (\$/kg) of selected hydrogen production methods (unsubsidized)



Biomass

Analysis of biomass supplies is greatly helped by the wide availability of retail price information.⁸² Assuming no additional costs in the process of burning biofuels, the authors estimate heating prices in table 8. Unsurprisingly, these costs are substantially higher than direct combustion of methane because of the low energy density of biofuels and the thermodynamic losses from biofuel manufacturing.

Table 8: Heat price of biomass

Biomass fuel	Retail prices (April 2019)	Calorific value (LHV)	Density	Price
Wood pellets	245 \$/ton	16.4 MJ/kg	N/A	14.94 \$/GJ
Biodiesel (B20)	2.88 \$/gallon	43.92–45.03 MJ/kg	0.85 kg/L	19.88–20.38 \$/GJ
Biodiesel (B99-B100)	3.51 \$/gallon	37.6 MJ/kg	0.88 kg/L	28.03 \$/GJ
Ethanol (E85)	2.31 \$/gallon	26.7 MJ/kg	0.789 kg/L	28.97 \$/GJ

Sources: Retail prices: US Department of Energy, US Energy Information Administration;⁸³ calorific value: Engineering ToolBox⁸⁴

Nuclear

Using the case record of the conventional nuclear power plants provided by the International Atomic Energy Agency, the authors selected one representative case for each reactor and use its heat rate as the efficiency of this reactor type.⁸⁵ To estimate LCOE of a conventional nuclear power plant, the authors combined various sources⁸⁶ and ultimately selected 78 to about 120 \$/MWh as the range. The actual LCOE could prove significantly different based on plant designs and geographic distribution (i.e., different countries).

For small modular reactor estimates, NuScale⁸⁷ is the only company to have reached advanced permitting in the United States. To bring this technology to market, its goal is to produce electricity at a total cost, including construction and operations, of \$65/MWh to about \$75/MWh and anticipating a capacity of 60 MWe. Since NuScale uses an internal PWR, the authors assumed a heat rate of 34.25 percent (like most PWR reactors today), although a higher heat rate is possible when put into production. To estimate heat production, the authors assume that the energy that normally generates steam for electricity is used for direct heat production.

Estimating potential heat costs for advanced reactors is more of a challenge because of the lack of operating plant data. The US Energy Information Administration’s 2022 nuclear power forecasts LCOE at \$90.1/MWh based on the 2017 nuclear power data.⁸⁸ Generation IV nuclear reactor’s efficiency is expected to be higher than conventional reactors (cf. above 45 percent), and other sources provide similar ranges for advanced nuclear LCOE estimates.⁸⁹ Based on



these predictions, the authors estimate the heat cost of the advanced nuclear reactor designs but recognize that major uncertainties remain.

Table 9: Heat cost of nuclear

Nuclear to heat	LCOE	Efficiency	Cost of heat
BWR	78-120 \$/MWh	33.75%	7.31-11.25 \$/GJ
PWR	78-120 \$/MWh	34.25%	7.42-11.42 \$/GJ
Small modular reactor	65-75 \$/MWh	34.25%	6.18-7.14 \$/GJ
Advanced reactors	70-110 \$/MWh	45%	8.75-13.75 \$/GJ

Sources: LCOE: Lazard, Adrian Cho, and the US Energy Information Administration;⁹⁰ efficiency: International Atomic Energy Agency⁹¹

Electrical Heating

Estimates for electrical heating start with industrial electric prices for all US states, ranging from \$46.4-\$200.87/MWh and with an average industrial power price of \$69.2/MWh.⁹² This differs from approaches of those who use LCOE or recent power purchase agreement prices. The authors use these assumptions to reflect the same duty cycles as industrial facilities, recognizing that grid power is not low-carbon power today.

Resistance heating is surprisingly efficient. Conversion of power to heat is nearly 100 percent efficient.⁹³ The authors assume 100 percent conversion efficiency for the assessment. However, most estimates do not include the efficiency of heat deposition into the system itself, which is process and facility specific. For direct heating, the conversion efficiency cannot be summarized, and therefore, the cost is not estimated here (see Appendix A for more information).

The authors' estimated costs use two ranges of electricity wholesale price (see table 10). The lower range (\$40-\$90/MWh) is representative of most US industrial electric power contracts, and the higher range is more typical of EU industrial power contract prices⁹⁴ (see figure 5). In all cases, the authors assume 90 percent capacity factors, again consistent with industrial contracts.

Table 10: Heat price of electric heating

Electricity to heat	LCOE	Efficiency	Price
Resistance	60-120 \$/MWh	100%	16.7-33.3 \$/GJ
Resistance	40-90 \$/MWh	100%	11.1-25.0 \$/GJ



It’s worth noting that the cost of resistive heating can vary by a factor of two, strictly as a function of local industrial power costs. This suggests that in some locations and industrial ecosystems, electrical resistive heating may prove competitive, which has large implications for the carbon footprint. Today in the United States, low-cost electricity comes from fossil generation, while in Europe, low-cost electricity comes mostly from hydropower and nuclear, both low-carbon sources.

Generic Cost Summary

Table 11 summarizes key heat options for industrial applications. This represents present conditions, systems, and costs, again reflecting the core focus of this analysis, namely to understand what is actionable today within existing facilities. It is important to note that the authors do not discount future potential for lower cost systems. For example, if firm, low-carbon power prices dropped significantly (e.g., three to five times reduction) then both green hydrogen and electrical heating would be more competitive. This is also true for improvements in nuclear heat systems or CO₂ capture systems.

The actual carbon footprint varies substantially, from near zero (renewable hydrogen) to substantial (53 percent CCUS hydrogen) to variable (electric heating, biomass). Estimated heat costs vary by a factor of eight. All costs are substantially higher than current sources of industrial heat. The ability of these sources to serve in specific industrial applications is discussed below and detailed in Appendix B.

Table 11: Heat cost summary

Heat option*	Heat cost minimum (\$/GJ)	Heat cost maximum (\$/GJ)
Hydrogen SMR (without CCUS)	8.8	12.5
Hydrogen SMR (53% CCUS)	11.0	14.7
Hydrogen SMR (89% CCUS)	14.2	17.9
Hydrogen renewable	40.0	69.0
Biomass	15.0	29.0
Advanced nuclear	8.8	13.8
Electric heating (60-120 \$/MWh)	16.7	33.3
Electric heating (40-90 \$/MWh)	11.1	25

*Biomass includes both wood and biofuels. Hydrogen renewable includes hydropower, wind (unsubsidized), and solar to hydrogen.



ADDITIONAL INDIRECT (SYSTEM) COSTS

The estimated costs above focused on the direct costs associated with the production of alternative heat supplies. Potential indirect costs also exist, including additional required infrastructure, additional maintenance, downtime and associated lost revenues, and capital upgrades necessary to use alternative heat supplies. These indirect costs could be substantial and may limit the rate and scale of low-carbon heat deployment. In some cases, the burden of indirect cost will not fall on facilities or owners but rather on governments or ratepayers, who would be responsible for financing infrastructure or additional tariffs.

Hydrogen Indirect Costs

The analysis above assumed on-site production and storage of hydrogen. For blue hydrogen, this assumes adequate existing natural gas infrastructure and near-site storage of CO₂. For green hydrogen, this assumes adequate power supply and on-site electrolysis. Satisfying these conditions might require additional infrastructure (e.g., additional gas or power transmission to facilities, CO₂ pipelines away from these facilities), and facility upgrades.

If on-site hydrogen production is not possible, hydrogen transportation systems would be required.⁹⁵ Industrial hydrogen pipelines exist in the United States—roughly 1,000 km in total—largely along the Gulf of Mexico’s heavy industrial corridor. Building additional hydrogen transportation systems could add substantial direct costs to operators, either from merchant carrier systems or private pipeline networks. Alternatively, pipelines or power networks could be supplied by local or federal governments through policy support.

Some on-site H₂ storage is likely to be required. For typical commercial high-pressure vessels, current H₂ storage costs are roughly \$15/MWh for power-to-gas energy storage systems, equivalent to \$4.2/GJ⁹⁶ based on existing H₂ storage projects. This number could drop with increased project scale and the development of novel hydrogen storage technology.

Hydrogen transportation systems require special metallurgy to avoid hydrogen embrittlement and corrosion and special seals and gaskets to avoid hydrogen leakage. The likely cost of using H₂ gas pipelines is almost the same with electricity transportation costs in terms of \$/km*J, approximately 10 times higher than liquified natural gas tankers and natural gas pipelines.⁹⁷ One approach to limiting the indirect cost of hydrogen might happen through such infrastructure improvement.

Biomass Indirect Costs

Biomass and biofuel can be treated as typical solids or liquid fuel for transportation. However, the energy density of wood and ethanol is lower than coal and gasoline, effectively raising the heat energy cost as a direct cost. An indirect cost is competition for land use and costs associated with acquiring land, which is not represented in most current prices. If land were to be purchased to grow energy crops, this could substantially increase production costs and create political challenges associated with land-use priorities.



Biomass systems, especially solid systems, often have substantial costs beyond the feedstock itself, including storage, drying, and new feed systems. Retrofit of equipment for solid feed may be required. Some biofuels require additional postcombustion treatment because of impurities (sulfur, nitrogen, etc.).⁹⁸

The main challenge of biomass and biofuel comes from the production and supply. The transportation radius from harvesting adds costs and negatively affects the carbon budget of the fuel (see the “Life-Cycle Assessment Concerns” section and Appendix A). Overcoming this challenge could also add substantial costs, especially if biomass energy production required long-distance transportation (e.g., shipping from distant locations to industrial sites).

Indirect Costs for Other Heat Options

Today, nuclear heat is used to produce steam. This is associated with thermodynamic losses and capital costs. Although nuclear heat could be harvested directly from reactors and used to operate chemical reactors or industrial processes, this approach has not been used anywhere to date. It is also unclear what implications such approaches might have for safety, corrosion, operational longevity, nonproliferation, or permitting, all of which add substantial indirect costs.

Transportation of electricity will use the existing electric grid or enhanced grid for industrial purpose. Additional electrification of heavy industry may require additional transmission and distribution systems and additional associated costs. Other indirect costs for electrification include additional utility planning and maintenance.



LIFE-CYCLE ASSESSMENT CONCERNS

The primary value of applying low-carbon heat to industrial applications is decarbonization. The uncertainty associated with replacing carbon-intensive heat supplies with low-carbon alternatives requires analysis to understand the life-cycle impact of substitution. A life-cycle assessment (LCA) on the carbon footprint is an essential tool for achieving that understanding.

Although there are small indirect carbon footprint additions to making capital equipment of all kinds (e.g., concrete for hydropower, steel for wind, aluminum for solar, etc.), most life-cycle analyses reveal that the footprint of manufacturing energy equipment is very small compared to use or fuel consumption.⁹⁹ The authors focus broadly on the specific alternative supplies and their LCA performance.

Carbon Footprint of H₂

The footprint of hydrogen production varies considerably by process. For gray hydrogen, H₂ is produced from SMR of natural gas. Without CCUS, gray H₂ cannot provide low-carbon heat since the production of H₂ requires additional heat and is very carbon intensive.¹⁰⁰ Using gray H₂ to replace conventional fuel (e.g., natural gas) would increase carbon emission because of conversion losses and added heat requirements for production. In addition, the LCA for gray hydrogen (and blue hydrogen) must include the upstream emissions from natural gas production. If production and transmission of natural gas involves poor practices (e.g., flaring, venting, or substantial methane leakage), the footprint can be very large.¹⁰¹

For blue hydrogen produced from gas reforming with CCUS, the footprint depends on the capture rate (fraction of total carbon captured) and the specific process and methodology used. For a given site and application, any upstream life-cycle footprint of gas production would attach to the blue hydrogen as well. Operators wishing to use blue hydrogen as a decarbonized heat source must take care to procure gas from producers with demonstrated good practices and robust accounting to verify their associated emissions footprint.

Green hydrogen is produced from low-carbon renewable electricity, such as solar and wind, used to drive electrolysis of water. The LCA for green hydrogen is the product of the carbon footprint of the electricity used and the electrolyzer conversion efficiency. If grid-based electricity is used, the footprint of the hydrogen produced by electrolysis would reflect the power footprint (see below).

Carbon Footprint of Biomass

Biomass is sometimes regarded as a carbon-neutral energy source. In truth, the carbon footprint for different feedstocks, fuels, and applications varies considerably.¹⁰² Fully representing biomass in terms of its GHG impacts remains a substantial challenge and can be extremely complicated and controversial.

In some cases, biomass energy only slightly reduces the carbon footprint.¹⁰³ For example, producing bioenergy (harvesting, chipping, drying, pelletizing, and transportation) most



commonly uses fossil fuels and can add as much as 20 to about 25 percent to LCA estimates.¹⁰⁴

It can be worse.¹⁰⁵ One very large potential contribution to an LCA footprint is carbon leakage, wherein biomass crops displace food crops, leading to deforestation. In some cases, biofuel crops have directly contributed to environmental destruction with very high GHG emissions consequences (e.g., for Indonesian palm oil). Poor combustion of biomass can add to LCA through contribution of black carbon, which acts as a warming aerosol. These cases show that biomass can potentially emit more carbon into the atmosphere than coal and other fuels, along with particulate matter and other pollutants.¹⁰⁶

There appears to be broad consensus that the best source of biomass is waste or byproduct biomass (e.g., wood wastes from the paper and pulp industry, forestry residuals, and agriculture products). These sources can be reproduced fairly quickly. For wastes associated with fugitive methane emissions, many systems of carbon accounting award additional credits toward avoided or reduced methane emissions to count toward the life-cycle score.¹⁰⁷ However, industrial heat demands for waste biomass would have to compete with demands for biomass power and biofuels.

Because of the uncertainties associated with the carbon footprint of biofuels in general, even for specific applications and contexts, full life-cycle analyses are essential to understand and present the true CO₂ abatement provided. In some cases, substantial research will be required to understand the situation, and substantial uncertainties and controversies may follow investment decisions. Policy such as carbon-based performance standards may be required to avoid retrograde outcomes and poor capital allocation.

Carbon Footprint of Electricity

As low-carbon electricity supplies gain market share, electrification becomes a viable and important pathway to provide low-carbon heat. The extensive scholarship on LCA associated with electricity generation has produced many tools and data sets to assess the carbon footprint of power systems on a national, regional, or local basis. This means that it's relatively straightforward to understand the carbon footprint of power purchased locally on a power-use basis. Similarly, for a single facility, it is relatively straightforward to determine how much decarbonization could be furthered by partial substitution of low-carbon power supplies for the grid equivalents.

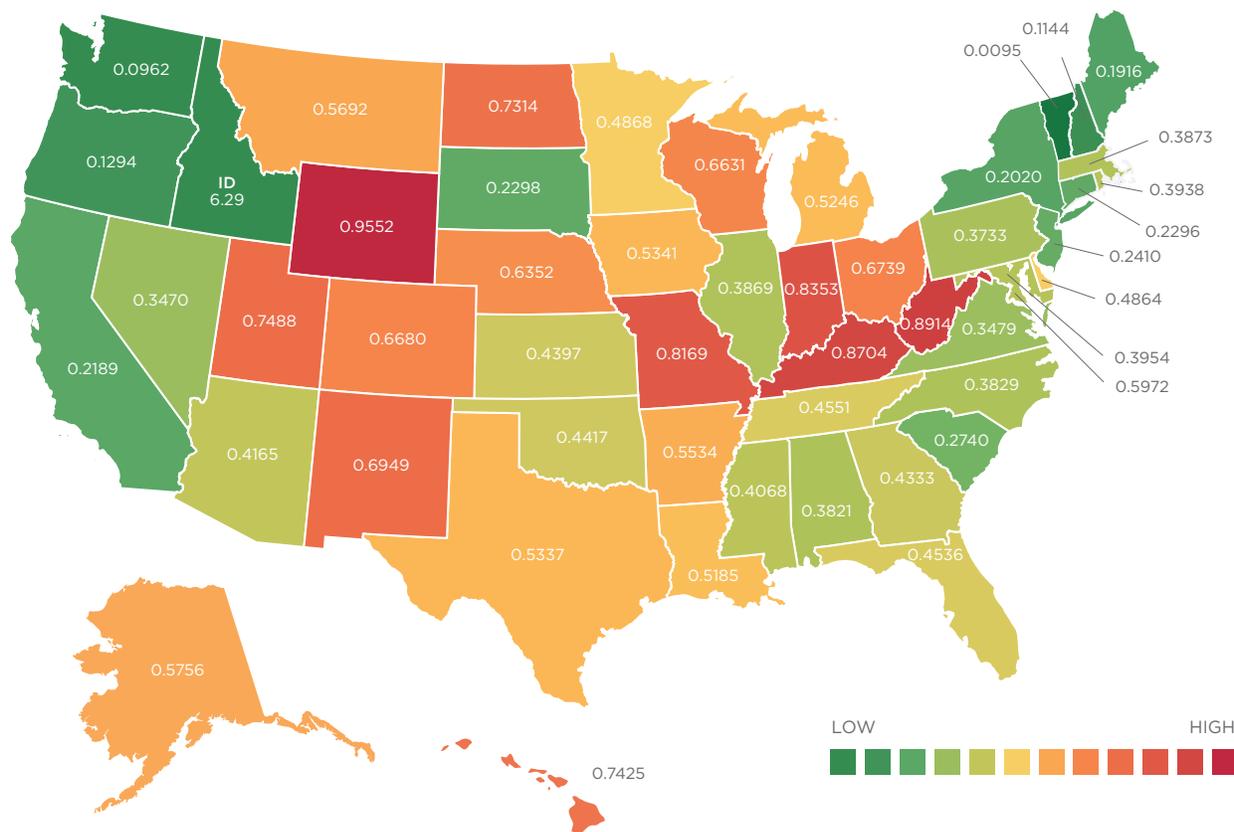
Electricity generation contributes roughly one-third of global emissions from the energy sector and roughly one-quarter of the total GHG emissions. Depending on the region's and grid's power supply, the carbon footprint of electricity varies considerably. For example, generation from 100 percent renewable electricity would have a near-zero carbon intensity (3 to about 40 kg CO₂/MWh).¹⁰⁸ Generally, low-carbon electricity sources (e.g., wind/solar, hydro, nuclear, and fossil with more than 90 percent carbon capture) can achieve near-zero carbon emission, typically only 1 to about 10 percent of the fossil fuel plants, depending on the engineering details and production technology.

LCA emissions for power generation vary widely across the United States. Figure 7 shows the electric power generation carbon intensity for each state.¹⁰⁹ The national average of



electricity carbon intensity is 460 kg CO₂/MWh, roughly the standard emissions for natural gas power generation. California’s electricity carbon intensity dropped from 400 to 220 kg CO₂/MWh between 2008 and 2018, mainly because of the aggressive deployment of renewable power generation. Texas, where natural gas dominates power generation, emits 530 kg CO₂/MWh, whereas Wyoming, the biggest coal-producing state in the United States, emits 950 kg CO₂/MWh.

Figure 7: 2017 US electricity generation carbon intensity by state (metric ton CO₂e/MWh), with national average of 0.46



Source: US Energy Information Administration

Regarding electrification as a substitute for other fuels and operations, LCA scholarship has focused principally on vehicle electrification. Industrial systems are substantially different from light-duty vehicle applications, in part because electric drivetrains are more efficient than those associated with internal combustion and diesel engines. In contrast, it is not clear that electrification of the industrial system will dramatically improve plant or operational efficiency, and in many cases, it may require much more electricity to provide the same industrial heat service—especially if heat deposition into industrial systems is inefficient. Understanding these concerns remains an important avenue for future work (see below).



CONSIDERATIONS OF SPECIFIC INDUSTRIAL APPLICATIONS

For application on specific industries, the authors' analysis focuses on cost comparison for *theoretically* possible heat replacement. In this analysis, the authors regard heat replacement as viable as long as the heat quality is sufficient both in temperature and heat flux (see tables B.2.1 and B.2.2). Major technology and engineering improvements are required for some heat replacement pathways (e.g., electrification and nuclear). To simplify the preliminary investigation, the authors assume such technology is available. The only cost increment assessed is because of heat replacement itself. To clarify the results, the authors provide costs both in terms of increases in incremental production (e.g., \$/ton steel) and the fractional increase in cost (e.g., 50 percent increase in unit steel production). The different energy density for each industry (i.e., heat required for producing unit mass of product [MJ/ton production]), carbon density (i.e., emission for production unit mass of product [CO_2 ton/ton production]), and original fuel (coal, natural gas, electricity, etc.) all affect the final calculation¹¹⁰ (see tables B.1.1 and B.1.2).

To compare different low-carbon heat options against other decarbonization options, the authors consider CCUS retrofits. The authors assessed two cases: CCUS applied only on the industrial heat part of emission and CCUS applied to the entire facility, including byproduct process emission from chemical reactions (e.g., reduction of coke to make iron and steel). For this, the representation in the charts below includes both CCUS applied only to the heat source (CCUS heat) and to the complete industrial process (CCUS total facility). That would provide a comparison of heat versus total decarbonization as well as a representation of how much additional cost/work is needed to fully decarbonize a site. The authors assume additional heat supplies are added to the system; conventional CO_2 capture systems are used; the costs of CO_2 capture are inversely proportional to the partial pressure of CO_2 in the emissions stream; and the additional costs of compression, transportation, and storage of pure CO_2 are \$25/ton, leading to a total cost assumption of \$60-\$150/ton. In all cases, CCUS is represented solely as a cost, and the authors' estimates do not include revenue from CO_2 sales or utilization.

No efficiency penalties are included in this analysis. The authors recognize this assumption is unrealistic, since adaptations of existing systems will likely cause system losses and require additional input energy. The authors assume all reaction processes and heat inputs remain constant while only hypothetical heat source substitutes are applied. This means the authors' estimates probably underestimate costs, as efficiency losses would increase unit production costs.¹¹¹

Note: These analyses do not represent the carbon footprint associated with these methodologies or the cost of providing low-carbon heat on a \$/ton avoided basis. In some cases (e.g., electrification, biofuel), the costs are associated with specific production pathways, each of which has a representative footprint or range. It may prove many options, whether low or high in cost, only achieve partial decarbonization. Again, this means our estimates probably underestimate the true cost of decarbonization for pathways other than CCUS.

In short, this analysis is preliminary and probably represents optimistic cost estimates since the authors do not account for capital costs for equipment substitution, thermodynamic



losses, or partial decarbonization effects. The authors also recognize that some applications (e.g., electrical resistance heating of rotary kilns or full plant application of CCUS to a methanol facility) may prove unworkable. These and other missing costs or viability components represent opportunities for future research (see the “Future Work” section).

Finally, in all the figures below, the authors assume coal or \$3.5/MMBtu to represent the zero value for industrial heat—typical of US natural gas prices. The \$8/MMBtu is meant to provide reference for costs for higher priced fuel (e.g., natural gas in Europe or Asia).

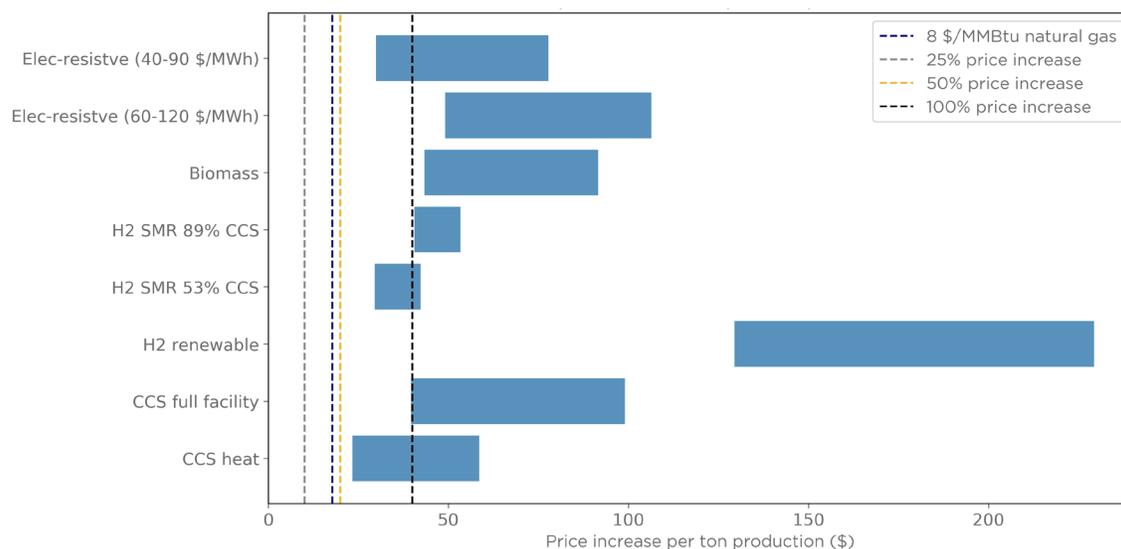
Clinker Production (Cement)

Analysis of the cement clinker kiln is based on dry process rotary clinker kiln cases (wet clinker production is less energy efficient compared with the dry process, which uses the residual heat of combustion to preheat the wet reactants¹¹²). Roughly 59 percent of carbon emission of cement clinker production comes from direct combustion to produce heat.¹¹³ The second largest portion of carbon emissions is reaction-associated carbon emission. The balance is indirect carbon emissions, such as electricity and transportation.

Dry clinker production requires 1,450°C minimum temperature, which limits potential low-carbon heat options to H₂ and biofuel combustion and electric resistive heating. The original fuel for cement clinker production is assumed to be coal (which is commonly the case).

With these options, only blue hydrogen (natural gas SMR plus CCUS) appears to hold the potential for a lower cost than CCUS on heat production (see figure 8). For the case when power costs are extremely low (e.g., \$0.04/kWh firm), it may be possible to electrify heat, but substantial engineering improvement will be required with uncertain costs. The lower cost bounds for all replacement heat sources are all close to full-facility CCUS costs (with the exception of renewable hydrogen, which is much higher).

Figure 8: Cost increase per ton of clinker, assuming coal as original heat source



All options other than blue hydrogen would result in clinker prices at least 50 percent higher and in most cases likely double the price. The main reason is that clinker is very cheap to produce, as low as about \$40/ton, while the carbon intensity is high. Heat for cement production represents at least half the production cost, making the product costs especially sensitive to fuel cost. This suggests that heat substitution in cement may prove prohibitively expensive with CCUS as the preferred option. In contrast, all pathways could dramatically improve in the future with more advancements in technology, system integration, and process design.

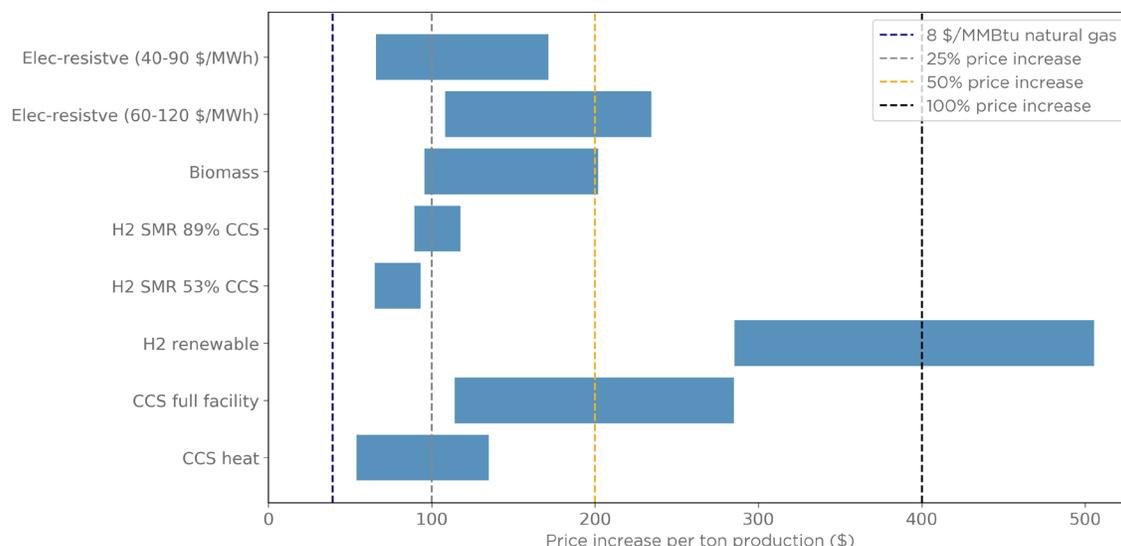
Steel Production

The authors' analysis focused on blast furnace operations specifically. The authors assumed coke and coal as the primary heat sources. The operational temperature requirement is 1,200°C, again, restricting options to H₂, biomass, and electric resistive heating.

Blast furnaces consume up to 75 percent of coal energy content in an integrated facility,¹¹⁴ which provides primary energy and results in carbon emissions. Energy costs represent a substantial fraction of steel production costs (20 to about 40 percent) depending on fuel type, fuel price, and the full operational technology suite. Although the blast furnace consumes most of the input energy and emits most of the CO₂, fractional costs on blast furnaces' energy input alone is much smaller than for cement production.

The incremental cost increase for heat supply substitution is similar to the cement clinker case, with the two options of blue hydrogen and CCUS on heat production alone appearing to be the most cost competitive (see figure 9). Most other options overlap the range of the full facility CCUS baseline, except for renewable hydrogen, which is most expensive.

Figure 9: Cost increase per ton of steel, assuming coal as original heat source



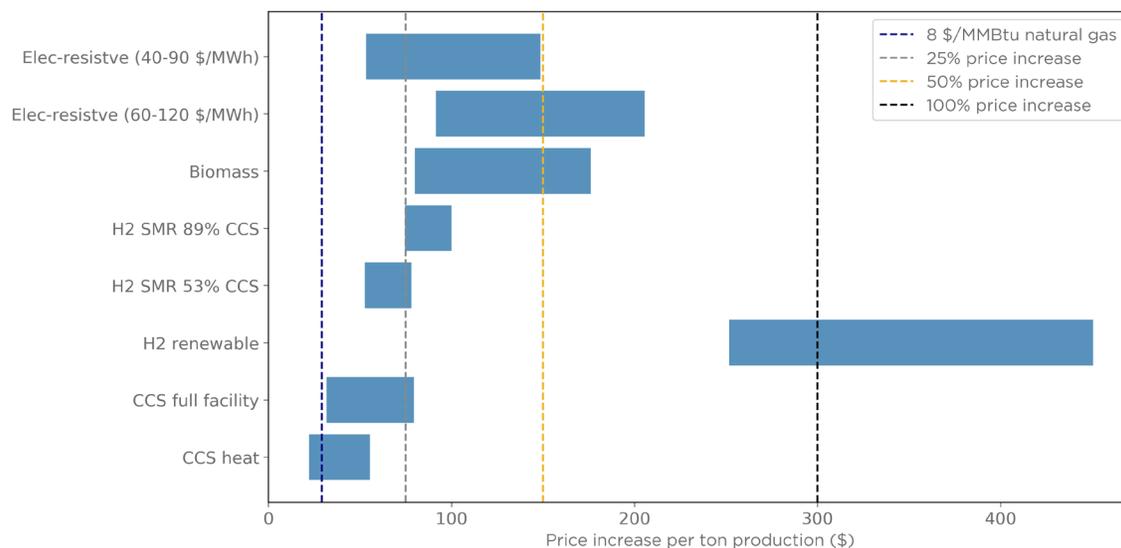
Applying replacement heat sources would cause the blast furnaces' energy costs to rise dramatically, from less than 10 percent to roughly 20 percent as a function of the technology option. This would cause the remaining energy costs to grow from 20 to about 40 percent for a total increase of 30 to about 50 percent. The effect on the final product's price appears more manageable than the cement case. However, since steel costs more than cement, the total cost to consumers would be greater on a unit production basis.

Glass and Ceramics

Glass furnaces require very high temperatures for operation: 1,500°C minimum with typical target temperatures around 1,575°C. Glass furnaces consume about 60 to about 80 percent of the energy input for typical flat glass and container glass manufacturing, with somewhat lower fractions for specialty glass and fiberglass. For flat and container glass, heat produces about 70 percent of the total emission.

Natural gas is the typical fuel in the United States for glassmaking and is used as the basis for comparison in figure 10.

Figure 10: Cost increase per ton of glass, assuming 3.5 \$/MMBtu natural gas as original heat source



Applying CCUS on furnace systems only does not dramatically change the unit cost of glass production and is nearly identical to CCUS applied to the total system. The two CCUS options, along with blue hydrogen, yield a roughly 10 percent hike on production costs. Most other options increase costs roughly 30 percent, while renewable hydrogen effectively would double production costs.



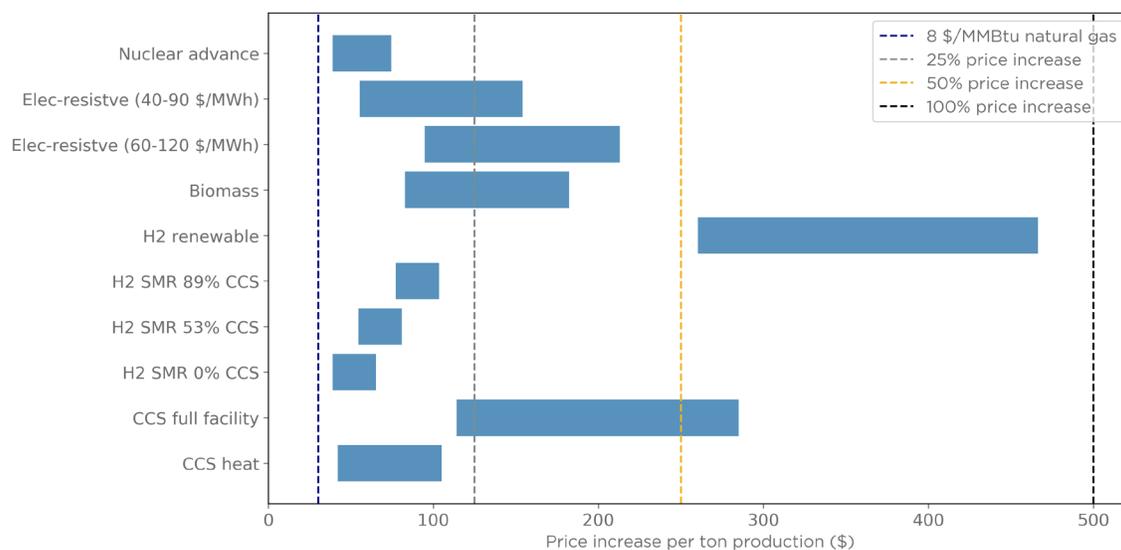
Ammonia Production

Ammonia is essential for fertilizer production, which affects food production and national security. Ammonia is also a potential substitute liquid transportation fuel and a potential option to ship hydrogen with minimal associated GHG emissions. One of the most energy-intensive industries, ammonia production consumes about 1 percent of total energy around the world. The Haber-Bosch process is the main industrial procedure for ammonia production ($N_2 + 3H_2 \rightarrow 2NH_3$), typically coupled with hydrogen production from SMR or coal gasification.

The ammonia operation requires temperatures of 800°C, chiefly to operate the SMR process to make hydrogen. The Haber-Bosch process operates at about 450°C. These temperature ranges allow heat from advanced nuclear systems to conceivably apply. An additional comparison is added to ammonia production: H₂ without CCUS applied (use hydrogen on-site) as a basis for comparison with current practice.

Unsurprisingly, ammonia production using on-site H₂ SMR without CCUS (today's practice) yields the lowest cost addition but almost no decarbonization (see figure 11). The estimated cost increment associated with CCUS applied to heat sources is less than 10 percent, close to that of blue hydrogen. Since H₂ is a critical feedstock to ammonia production, there may be additional synergies that come from additional H₂ generated on site as a heat source.

Figure 11: Cost increase per ton of ammonia, assuming 3.5 \$/MMBtu natural gas as original heat source



Using ammonia as a proxy for relatively high-temperature kinds of petrochemical production reveals an intuitive fact: decarbonization is expensive. In this analysis, the more decarbonized the heat source is, the more expensive it is as well, which affects total product cost. Deep decarbonization options such as green hydrogen and CCUS on the full system are among the



most expensive choices. The other options that have relatively low cost either offer limited decarbonization (e.g., on-site H₂ without CCUS) or are too speculative or uncertain to deploy (e.g., advanced nuclear heat).

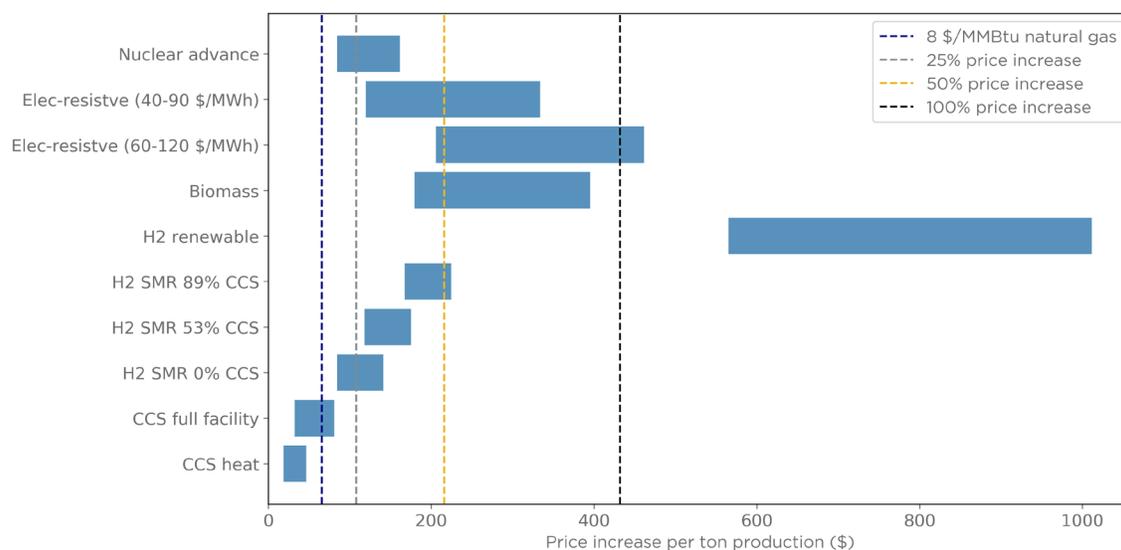
Petrochemicals (Methanol) Production

In contrast with ammonia, methanol (CH₃OH) production can serve as a proxy for low-temperature petrochemicals' synthesis and can also serve as a proxy for novel low-carbon fuels.

To model methanol production, the authors combined syngas production from natural gas with methanol synthesis. Syngas production is similar to the SMR operation but without separation of H₂ and leaving the other chemical byproducts (e.g., CO and CO₂) as methanol feedstocks.

The comparison results reveal that CCUS applied directly to heat or the whole facility appears to be the lowest cost decarbonization pathway (see figure 12). This is also the only case when a clear winner seems apparent for all pathways. The authors believe two factors are most important. First, methanol production is energy intensive, making replacement heat sources expensive to unit costs. Second, carbon is an essential chemical feedstock that remains in the product, greatly reducing the carbon intensity of methanol production. However, it may prove that applying CCUS to the heat sources in these facilities is prohibitively difficult. Many petrochemical plants (including methanol plants) have tens to hundreds of small distributed heat sources (burners and furnaces), which may prove unworkable for CCUS from an operational perspective. Additional analysis is required to test this initial conclusion.

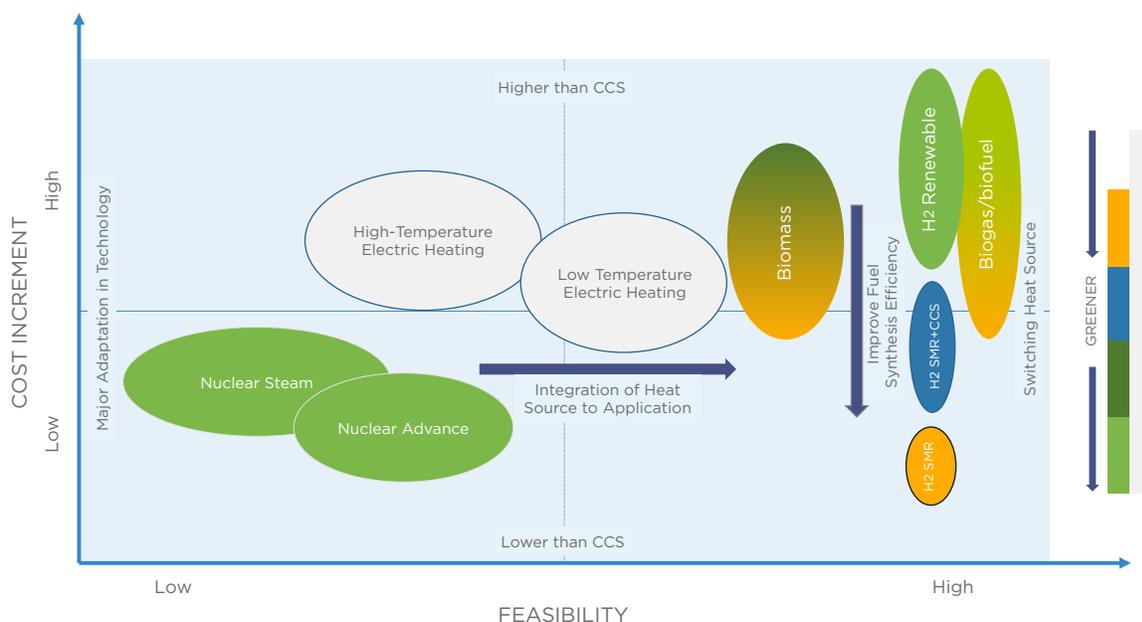
Figure 12: Cost increase per ton of methanol, assuming 3.5 \$/MMBtu natural gas as original heat source



CONSIDERATIONS OF VIABILITY

Assessment of viability is fundamentally more complicated than this initial analysis could undertake. True assessment of viability requires plant-specific representation of reactor devices (including size); physical plant layout; hypothetical heat deposition systems; and other complex and complicated representations of operational physics, chemistry, and engineering. While this is essential future work, the authors could provide only a qualitative assessment based on their current understanding of likely process engineering and technology readiness (see figure 13). Again, for comparison, the authors use post-combustion CCUS as an option.

Figure 13: Qualitative feasibility chart for options of heat¹¹⁵



Note: The colors represent the carbon intensity, with yellow having high carbon intensity and green having low carbon intensity. For electrification and biomass, the gradients reflect the path dependency of specific carbon footprints as a function of supply.

For hydrogen and biofuels, substitution for traditional heating fuels is fairly straightforward. There would be issues to manage with sensors and controls, safety, biomass structure, energy density, and others, which are well known and fundamentally manageable. In most cases, substitution of hydrogen or biogas for a gaseous fossil fuel or biodiesel for a liquid or gaseous fossil fuel would require minor plant modifications (e.g., to manage invisibility or hydrogen embrittlement). These could include the substitution of burner tips, modification of sensor and control systems, and replacement or modification of storage tank systems.



Substitution of hydrogen, biogas, or biodiesel for solid fossil fuels (e.g., coal, petcoke) is also relatively straightforward and would require modification of feed systems and additional burner modifications. These modifications have relatively low capital costs and are fairly easy to implement but could result in additional costs associated with the different combustion pathways. For example, pure hydrogen combustion would yield hydrogen radicals that could present problems as an impurity for product quality control. However, for some applications (e.g., blast furnace operation), solid fuel plays multiple roles in production and may prove difficult to replace, even with solid biomass sources. Future study is required to assess the likely cost and performance implications for specific facilities.

Substitution using other low-carbon heat supplies is substantially more difficult and more expensive. For electrification and nuclear heating, major technology advances would likely be necessary to make such heat options viable. For instance, using electrical or nuclear heating systems to generate steam would likely require substantial modification of existing boiler systems or complete substitution and plant reengineering. In many cases, the potential low-carbon replacement system has low technical readiness¹¹⁶ and is not available in the market today. In a few cases, there are theoretical designs that could provide a means of retrofit implementation (e.g., electrical heating of limestone to produce cement clinker, hybrid direct reduction of iron (DRI)/electric arc furnaces¹¹⁷) but no currently available technology. For some low-carbon heat systems, complete plant reengineering or asset replacement would be required, accruing both the cost of the new system and the cost of decommissioning and reducing the asset's capital life.¹¹⁸

Figure 13 underscores a key finding: low-cost viable options are limited, and decarbonization of heavy industry is likely to prove expensive. In particular, the ability to replace many heating systems with electrical or nuclear options remains problematic. This finding also helps clarify a potential research agenda in applied engineering, focused on functionalizing key options and overall cost reduction. The research agenda should also comprise additional considerations, such as operational safety, environmental controls, and efficiency improvements.



PRELIMINARY TECHNOLOGY RANKING

The most promising technology options today that might be used to decarbonize industrial heat are CCUS and H₂. They are both among the cheapest choices for all assessed industries. CCUS is intuitive and universal and can also deal with process emissions. H₂ can provide enough quality of heat for all industries and appears viable for many applications, especially glass and petrochemicals.

Hydrogen provides heat by combustion, and the temperature/heat flux property is very compatible with current plants' designs. For some systems, a minimal retrofit is anticipated, suggesting low-carbon hydrogen could be relatively quick, easy, and cheap to deploy. Since H₂ is also the most important reactant for ammonia and petrochemicals' production, centralized low-cost H₂ supply can greatly simplify synthesis technology complexity, reducing costs. Hydrogen can also serve as a reduction agent, necessary for steel manufacturing, as is the case for DRI plants today. For these plant designs, a hydrogen pathway could decarbonize both industrial heat and chemical-reaction-related emission. For these reasons and others, H₂ is one of the most important agents for net-zero decarbonization in the future.

Although current H₂ production using SMR emits large amounts of CO₂, the incremental cost to production associated with partial or full decarbonization of an SMR is relatively modest and manageable, as evidenced by the three blue hydrogen facilities operating today. In addition, decarbonizing industrial heat with blue hydrogen could increase opportunities to use green hydrogen in the future, as costs drop and performance improves. Application of CCUS on SMR units is actionable in many settings and could pave the way toward green hydrogen in the future.

CCUS, on the other hand, is intuitive and straightforward and remains a proven and viable solution. For some cases (e.g., reaction emissions from clinker production and lime production), CCUS still serves as the only way toward decarbonization. Depending on costs for specific industries and sites (whether a storage site is available), CCUS appears the lowest-cost solution for net-zero carbon emission. Applying CCUS on existing plants could prove more straightforward and easier than the electrification and nuclear approaches.

Electrification remains an important option. Although not fully decarbonized yet, the pathway for power sector decarbonization is relatively straightforward. Based on the near-zero marginal cost of renewable power, electrification using low-carbon electricity could prove attractive. To serve industrial systems, firm and dispatchable supplies would be necessary to provide very high capacity factors. Although battery technologies have advanced and costs have dropped substantially, dramatic advances in cost and energy density would be needed to serve industrial customers cost effectively. At present, the low-carbon electricity price makes electrification less cost competitive with H₂ and CCUS outside regions with abundant low-cost green electrons (e.g., regions with abundant hydroelectric power with high capacity factors). Substantial research, design, and prototype demonstration is required to figure out all engineering details and therefore determine whether electrification is viable.



Advanced nuclear power could provide temperatures high enough for ammonia and petrochemical production, but no reactor designs appear sufficient to even hypothetically provide enough heat for glass, steel, and cement. Nuclear power continues to suffer poor public support (in part because of concerns about safety and nuclear waste) and is in decline in many countries, including the United States and EU. Nuclear heat applications provide new risks associated with novel operation (e.g., corrosion, maintenance). That said, the potential for advanced nuclear to produce low-carbon H₂ could prove important and another alternative for low-carbon hydrogen.

Biomass is complicated. Understanding the carbon footprint of the fuel is often a challenge, and unless waste biomass is the primary feedstock, the risk for carbon leakage and poor LCA remains. Today, costs are high and supply chains complicated. Large-scale production could lead to tradeoffs around land use.¹¹⁹ However, for those regions with abundant biomass resources (e.g., Brazil, California), biofuels could prove important. This may prove particularly true for those systems that require solid fuel feed or if there is accelerated demand and financing for CO₂ removal through bioenergy plus CCUS.¹²⁰

This initial ranking is highly speculative, uncertain, and contingent. Moreover, the actual technology ranking could vary significantly by geography and natural resource availability. For example, the costs for blue hydrogen are contingent on presence and access to nearby geological CO₂ storage sites and low-cost natural gas. Similarly, presence or absence of local hydro, wind, or solar resources will affect costs for green hydrogen and low-carbon electrification. This initial ranking is also temporary at best. Advancements in any technology pathway could lead to reassessment and revision.



IMPLICATIONS FOR POLICY

Because of the nature of industrial heat and its associated markets, low-carbon heat lies outside many conventional policy approaches. Despite interest in a “BTU tax” early in the Clinton administration, heat is generally not considered part of the economy and is not regulated, taxed, or even measured. Most gases and fuels (hydrogen, methane, biodiesel) are traded by mass or volume, not heat content. Most regulations focus on tailpipe emissions, which only indirectly affect questions of industrial heat (waivers and exemptions aside). Many industrial products are exempt from emissions taxes or tariffs.

To make progress on industrial heat decarbonization, a wider set of policy options is required, including some unconventional options. These policy design considerations should be observed to maximize value and minimize disruption or distortion of markets.

- As much as possible, policies should remain technology agnostic.
- As much as possible, policies should be applied economy wide, recognizing that specific options could be preferred locally because of engineering design or resource availability.
- As much as possible, policies should minimize direct impacts on the consumer.
- Policies should encourage private investment and innovation.
- Policies should focus on the desired outcome (emissions reduction from industrial heat systems) rather than mechanisms or specific pathways.
- All policies should be time limited and eventually phase out.

Ultimately, potential policies to deploy low-carbon heat options should respect and recognize the resource limits associated with geography, which include limits to renewable energy resources (e.g., solar radiance or wind strength), availability of CO₂ storage resources (e.g., for blue hydrogen production), and the geographic availability of key feedstocks (e.g., biomass, natural gas). To achieve the outcome desired—decarbonized industrial emissions—policy designs should allow maximal room for competing approaches and novel configurations

Infrastructure

A key policy option is public investment in common use infrastructure. Similarly, industrial facilities are clustered in regions because of the historical resource base (e.g., refining along the US Gulf Coast or steelmaking along the Great Lakes) and may be far from either critical infrastructure or low-carbon fuel supplies. Many of the options considered in this report lack infrastructure for delivery of decarbonized fuels—including hydrogen pipelines, CO₂ storage pipelines, biogas hookups—and enabling of high-voltage transmission lines. Some regions have such infrastructure (e.g., Gulf Coast), but they are not adequately sized or organized for deep decarbonization.



Providing critical infrastructure of this kind would likely provide opportunities to serve domestic industries and limit project costs through geographic colocation.¹²¹ Build-out of such infrastructure could lower the hurdle to adoption significantly, especially in industrial hubs and clusters.¹²² Infrastructure would be supported through omnibus legislation, direct government procurement, block grants or matching grants, regulatory fast tracking, facilitation of access to rights-of-way, and special tax treatment for key infrastructure projects (e.g., economic activity zones, private activity bonds, or master limited partnership status).

Procurement

A second option is the creation and promulgation of low-carbon procurement policies. The history of government procurements supporting technology advances is long and successful, including clean energy options such as LEDs, biofuels, advanced battery technologies, and high efficiency solar panels. Creating government procurement mandates for low-carbon industrial products (e.g., cement, steel, plastic, glass) could help stimulate companies by creating an early market for low-carbon industrial products.

Government procurement is a particularly appealing option because governments are the primary direct or indirect purchaser of steel, cement, and fuels. Much of this procurement is associated with infrastructure projects (e.g., roads, bridges, public buildings), and initial study suggests that primary industrial products and materials represent only a small fraction of total project costs. Said differently, adding substantial costs to industrial products could affect final project costs less than 1 percent.¹²³ If so, then the apparent cost to the public of procurement policies could appear small.

Several US states, notably California and New York, have created initial policies and are exploring further action. At the federal level, new policies have been introduced both legislatively¹²⁴ and through executive order.¹²⁵ In doing so, they provide model language to consider specific cost support by creating a customer base for industries adopting low-carbon heat options.

Importantly, this approach is not limited to governments. Many companies, including retailers and high technology manufacturers, have created internal policies governing the purchase of low-carbon power and greening their supply chains.¹²⁶ These policies provide clear market signals and help stimulate investment in production of low-carbon products. Expanding their policies to include low-carbon building materials and products could provide a point of entry for heavy industry to explore low-carbon heat production as a pathway to decarbonizing their product lines for customers, potentially with little or no impact on final product cost to customers.

Innovation Agenda

The apparent need for both more options and better options suggests an innovation agenda. Because heat is a cross-cutting topic (power, buildings, heavy industry), it is rarely the focus of government programs.¹²⁷ In contrast, there are enormous and long-lived programs on industrial efficiency,¹²⁸ which have yielded substantial gains in both cost and emissions.¹²⁹



In general, substantial public and private RD&D efforts precede major technical and commercial advances and have an excellent track record of public benefit. One recent example, the SunShot Initiative, dedicated an additional \$300 million to \$400 million every year to reduce the system and component cost of solar energy platforms.¹³⁰ A targeted innovation agenda on both production and enhancement of low-C heat options could provide opportunities for international partnership as well as public-private ones.

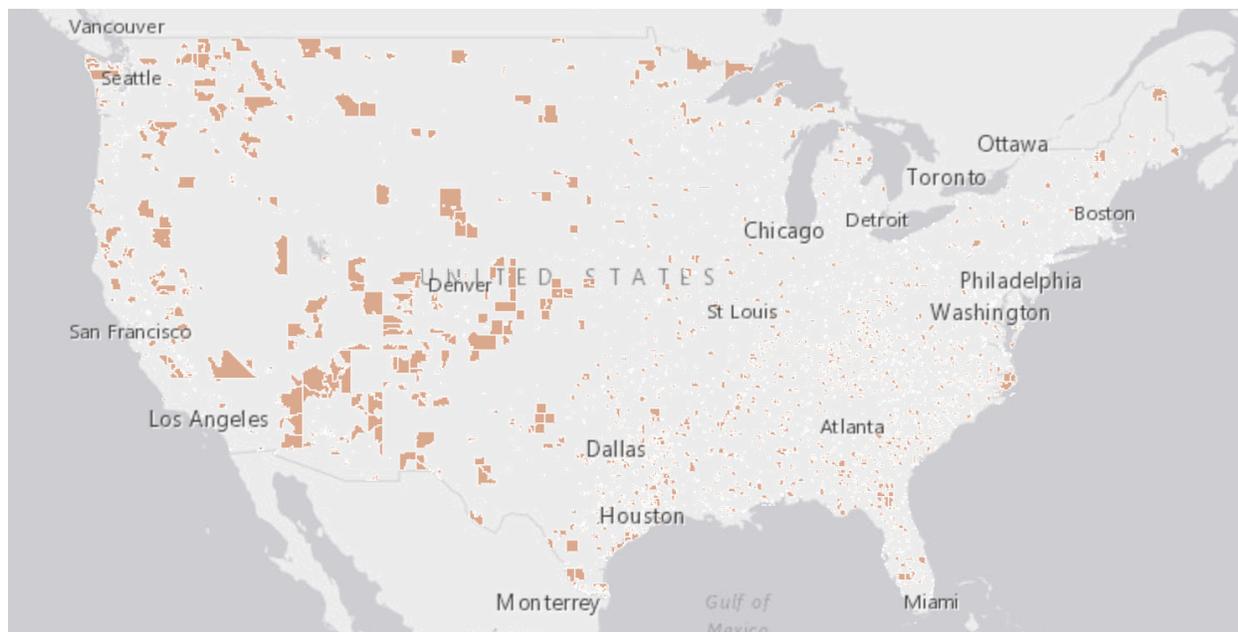
Because many industrial products are traded as international commodities, and because many of the technical and innovation issues are precommercial and precompetitive, there may be considerable benefits in stimulating international collaborative innovation efforts. One example, the Mission Innovation program, has created road maps and collaborative projects across many companies.¹³¹ Although industrial decarbonization is not one of the eight thrust areas within Mission Innovation, one could be created if two member countries voted to explore that possibility. Similarly, private or corporate entities could launch innovation programs unilaterally. Recently, companies have independently created partnerships to support and sponsor precompetitive RD&D directly relevant to commercial and environmental concerns.¹³² Given that many heavy industrial companies are inherently multinational in operations and investments, one could expect sectoral leaders to participate in a collaborative international RD&D program.

Additional Incentive Options

Since some options exist and others could be improved, well-structured incentives could drive early deployment and attended improvements in cost and performance (i.e., learning by doing) as well as stimulate private investment in innovation.¹³³ Governments could provide specific incentives targeted at decarbonizing industrial heat, with the recognition that this will help their future competitiveness. To date, many of these policies are technology specific (e.g., biofuel subsidies or the US solar investment tax credit). It is possible to design tax credits or treatments aimed at decarbonized heat as a specific objective. This would also help countries maintain competitiveness and avoid loss of market share due to wholesale price increases because of decarbonization of heat supplies.

Because many industries and their low-carbon heat resource options are geographically restricted, a geographically restricted financial incentive could be particularly effective. One example is the creation of economic opportunity zones (EOZs) in the United States (see figure 14), wherein states designate specific lands or districts for lower tax burdens to attract industry.¹³⁴ Theoretically, EOZs could be used to stimulate investment in additional low-carbon supplies (e.g., biofuels, low-carbon electricity) for local industry as well as to reduce the burden of capital reinvestment within existing districts.¹³⁵



Figure 14: Map of EOZs in the United States¹³⁶

Source: Economic Innovation Group and Esri, "Opportunity Zones" (2018), <https://eig.org/opportunityzones>

For some markets or industrial sectors, feed-in tariffs or contract for differences could provide sufficient incentive to companies. These mechanisms would provide contractual supplements to products delivered, similar to a procurement incentive but more widespread in the economy. If sufficiently large and reliable, companies and investors would put additional capital into facility upgrades and purchase more low-carbon fuels with the knowledge that they would not disadvantage themselves or their customers.

Operational and Regulatory Standards

Historically, regulation has proven an effective tool for reducing pollutant emissions from heavy industry. These include constraints on particulates, dust, volatile organic compounds, and sulfur. Already, some jurisdictions have placed emissions limits on carbon associated with heavy industry.¹³⁷ Many of these regulatory caps assess low-cost fees and have not yet yielded substantial reductions but could in theory.

Regulators have several options available to control emissions. They could implement an emissions cap either on total emissions or per unit of production (i.e., per ton of cement or steel). Given that some options for low-carbon heat could be cheaper than alternative compliance mechanisms (e.g., full-facility CCUS), this mechanism could prove effective in both reducing total GHG emissions and in stimulating adoption of low-carbon heat systems.

Importantly, operational and regulatory standards of these types can serve as a mechanism to



gather and share data publicly. Given the paucity of readily available information on process heat for heavy industry, the development and implementation of standards could provide government decision makers with critical insights to manage a transition to low-carbon fuels. It could also stimulate and codify life-cycle methodologies that would underlie regulatory and trade governance issues. Possible regulation would strongly benefit from data gathering of this type and could serve as an easy, low cost, and open start to tackling industrial heat emissions.

Low-C Border Tariffs

As discussed above, many relevant industries trade into international commodity markets. Part of the challenge in driving industrial decarbonization lies in the potential trade risks faced by domestic industry, which could lead to carbon leakage, job loss, trade deficits, and other negative consequences. One potential mechanism to guard against these outcomes is the development of a border tax adjustment (BTA), a tariff based on the carbon footprint of key materials (e.g., fuels, steel). Using some formula, a nation's government would apply a tax on imported goods related to their carbon footprint. This would provide a benefit in protecting domestic industry that pursues decarbonization as well as potentially incentivize trading partners to pursue decarbonization as well. For cases in which low-carbon heat is more economic than alternatives, a BTA could stimulate deployment.

BTAs on carbon have been considered for many years¹³⁸ but not implemented. In part, lawmakers carry concerns about the potential negative consequences, equity concerns, and World Trade Organization compliance. In theory, it is possible to structure BTAs with minimal negative consequences,¹³⁹ but to date politicians have been reluctant to undertake them. This may be changing both in the United States and overseas.¹⁴⁰



FINDINGS AND CONCLUSIONS

Finding 1: Significant GHG emissions result from a generation of heat for heavy industry.

These emissions represent roughly 10 percent of global emissions, and it is unlikely that climate stabilization can be achieved without managing heat-related industrial emissions. They represent an underexplored contributor to climate change risks and an underexplored opportunity to profoundly reduce emissions.

Finding 2: Few options exist today to reasonably substitute low-carbon heat sources.

Unlike the power sector and light-duty vehicles, the operational requirements of temperature, quality, flux, and high capacity place stringent constraints on viable options. These are further narrowed by geographic limits of natural resources and infrastructure. The true viability, cost, and carbon footprint of options remain poorly understood.

Finding 3: Data on low-carbon heat alternatives is scarce. International scholarship and analysis on decarbonization have focused on other sectors, and within the industrial sector, have focused on novel pathways for material production that could serve as a substitute. As such, primary and derivative data is limited and hard to assemble, which contributes to the lack of understanding of options and risks. The overall understanding of likely carbon footprint, viability, costs, and tradeoffs is poor.

- **Conclusion 1:** *National and regional governments with substantial industrial emissions should begin programs to understand their heat-related emissions.* This should include data gathering and dissemination, analytical programs to assess the nation's potential vulnerabilities and opportunities, and potential supply chain and infrastructure limits to substitute options for low-carbon heat.

Finding 4: All options for low-carbon heat face substantial technical, operation, and economic challenges. These challenges might include lack of viable engineering pathways to substitutions, limited supplies of key options or feedstocks, lack of enabling natural resources (e.g., CO₂ storage or biomass), and fully realized costs. It is possible that these options carry additional hidden risks such as leakage.

Finding 5: Today, most alternatives to generate low-carbon heat cost significantly more than current heating fuels and systems. Compared to fossil fuel costs (mostly coal and gas), all options show a significant price increase of 2–20 times. These costs are sensitive to price of feedstocks (electric power, natural gas, biomass) and almost certainly carry additional hidden costs associated with poor conversion efficiency, poor heat deposition in real facilities, and system related costs (e.g., infrastructure build-out)

Finding 6: Providing low-carbon heat would likely increase the wholesale cost of production substantially. Because high-quality heat is vital to industrial operations, increased cost of low-carbon heat would yield higher unit production costs. Increases would range from 10–200 percent, depending on heat supply, industrial sector, and specific application.



- **Conclusion 2:** *More options and better options are needed.* Given the urgency for deep decarbonization globally, options for substitution are essential. Given the paucity of good industrial heat-related emissions options, the current set is hard to deploy even with substantial subsidies. Researchers, governments, industrial leaders, and investors must add greatly to existing efforts to develop new and better solutions or to improve existing ones dramatically.

Finding 7: Many options for low-carbon heat do not appear competitive with CCUS retrofits on heat production systems or full plants. Based on current data, CCUS retrofits appear to have better costs than many options (including biofuels, electrification, and green hydrogen). CCUS retrofits on the entire facility, including byproduct emissions from key processes like coking and calcining, appear to be lower in cost than many options that don't deal with process emissions. While these estimates have large uncertainties, including estimates for CCUS retrofits, this finding may prove robust under additional assessment.

Finding 8: Today, low-carbon hydrogen appears the most versatile and lowest cost. The lowest cost, most universal option across sectors appears to be hydrogen from natural gas partially or fully decarbonized through application of CCUS on the production facility (blue hydrogen). Blue hydrogen appears to provide the easiest pathway to substitute in many facilities, especially those using natural gas today, and is straightforward to scale. Finally, blue hydrogen creates an on-ramp for green hydrogen, which may become more cost competitive as renewable power for electrolysis drops in price.

- **Conclusion 3:** *CCUS is likely to prove important.* In the near term, CCUS appears to be both an important enabler of low-carbon heat options (including biofuels) and may prove to be cheaper and simpler than substitution of many heat options. Given that, governments and industrial leaders should accelerate assessment of CCUS as an option for their enterprises and consider investing in both infrastructure and deployment.

Finding 9: Special policy options may be needed to decarbonize industrial heat. The high cost and low technical maturity of most low-carbon heat options in most applications limit policy approaches substantially. The complexities of trade, labor, and security are acute in heavy industry energy policy and politics, and the risk of backlash to poorly designed policy appears substantial. Many industrial sectors are exempted today from carbon control policies.

- **Conclusion 4:** *Several policy options appear both effective and actionable.* Of the policy options explored, government “buy clean” procurement policies appear to have low political risk and could stimulate private investment in low-carbon heat options by creating a new customer for low-carbon products—substantial volumes of industrial product are purchased directly by governments. An innovation policy also appears to carry low political risk while accelerating creation of new options and deployment of existing options by accelerating cost reduction and discovery.

Finding 10: Much more work is needed. This report and the analysis within it should serve as a departure point for further analysis and research. It is likely to require many researchers working over many years to provide definitive progress on viable options for low-carbon heat for industry (see below).



FUTURE WORK

It should be clear from this initial review and analysis that much work remains for scholars, engineers, and companies (c.f. finding 10 above). Finding viable, cost-effective options to provide low-carbon heat for industrial applications remains an essential effort in deep decarbonization and a difficult one. This is likely to take many years and involve analysis at many scales. Local designs and resource issues require deep and bespoke investigation, and many important national and multinational issues are emerging only just now.

At the Center on Global Energy Policy, the authors have begun to take up this challenge and anticipate future work involving these efforts:

- *Detailed technoeconomic assessments of specific facilities and assets:* The viability of retrofit approaches remains a central question. To understand the viability, detailed engineering models and studies are required on both representative assets (e.g., a generic steel mill) or specific facilities (e.g., US Steel's Mon Valley facility). Each of these sectors will require assessment and validation, ideally using detailed process engineering data and models (e.g., in ASPEN Plus).
- *Applied RD&D on novel methodologies:* It seems clear that more options are needed. Some approaches, such as direct electrical heating using radio frequency energy, or hydrogen production using the iodine-sulfur cycle, show great promise but require additional maturation. Progress will require dedicated federal and industrial RD&D investments in many potential approaches.
- *System integration and industrial ecology:* There may be many opportunities for improved overall efficiency and performance of industrial applications using low-carbon heat options. For example, hydrogen supplied to chemical plants can serve both for heating and as a feedstock and for steel mills as both a heating fuel and chemical reductant. Similarly, indirect electrical resistive heating may be integrated with waste heat recovery systems to gain overall plant efficiency. Optimizing these systems remains largely hypothetical, with questions remaining around the potential scale of opportunity, potential cost, and potential methodologies.
- *Tradeoffs between switching, retrofit, rebuild, and replace decisions:* The authors' analysis focused almost exclusively on replacement of existing heat sources with low-carbon alternatives. In some cases, it may be better to retrofit existing systems with CCUS systems. This is well explored within the power sector but relatively poorly explored for industry. Similarly, it may prove economically advantageous to replace component systems with low-carbon options (e.g., an electrically heated ethylene cracker) or even wholesale replacement of assets with alternative processes (e.g., direct electrical reduction of iron). Improved understanding of these tradeoffs is essential to policy planning and design.



- *Improved economic analysis:* Technoeconomic assessments are only one component of economic study. Many questions regarding market response, leakage risk, macroeconomic consequences, and related topics remain largely unexplored. For example, improved representation of industrial in integrated assessment models used by governments and international agencies for planning and analysis would help shed light on potential economic opportunities and risks associated with fuel substitution or system replacement.
- *Policy design analysis:* Even if potential technical options were more widespread and available, many conventional policy pathways may prove insufficient. This could be because of the inelasticity of price options (e.g., cement production relative to a carbon tax) or the complexities of the market (e.g., international trade network and industrial policy today). Scholars should begin to assess and analyze policy options designed for these industrial sectors and their potential to introduce low-carbon heat options, including policies to support a muscular innovation agenda.

Having begun this work at Columbia, the authors plan to continue working directly on some of these issues. Some of this work will continue within the authors' center, and some work will continue with partners in companies, other universities, and within the authors' university. The authors are glad to have seen some scholars and some nations begin work on this important topic. Hopefully, the sophistication of analysis and viability of options will look different even a few years from now because of this work and the work of others around the globe.



APPENDIX A: OPTIONS AND COSTS

A.1. Hydrogen Cost

For hydrogen production using electrolysis, literature about the current cost breakdown is more than 55 percent from electricity consumption and the rest from electrolyzer (more than 30 percent) and maintenance (about 10 percent). The cost is based on the \$40/MWh electricity price and roughly \$1,000,000/MW electrolyzer cost.¹⁴¹ Other assumptions include about 45 percent capacity factor (only operated when electricity price is low, e.g., midnight), fixed lifetime (4,000 hours per year and 20 years continuous), and 80 percent electricity-to-hydrogen efficiency.

For green hydrogen production and grid electrolysis while the electricity price is much higher (typically more than \$60/MWh), the cost breakdown will suggest that operating cost resulted by electricity consumption will be much higher than capital costs (mostly electrolyzers).

The authors' calculation about green hydrogen production cost breakdown shows great consistency with the literature, as shown in table A.1.1.

Table A.1.1: Green hydrogen cost calculation

Hydrogen production	Electricity cost (\$/MWh)	Capacity factor	Electrolysis cost (\$/kg)*	Additional cost (\$/kg)**	LCOH (\$/kg)	Cost of heat (LHV)
Grid electrolysis (PEM)	60–90	90%	3.08–4.62	1.42	4.5–6.04	37.52–50.34
Solar PEV	36–46	20%	N/A	N/A	7.1–8.3***	59.2–69.2
Solar PEC	N/A	20%	N/A	N/A	7.0–8.0***	58.4–66.7
Wind subsidized	14–47	35%	0.72–2.41	4.07	4.79–6.48	39.91–54.02
Wind unsubsidized	29–56	35%	1.95–3.18	4.07	6.02–7.25	50.17–60.46
Hydropower	30–60	40%	1.54–3.08	3.26	4.80–6.34	40.01–52.83

*Electrolysis using direct efficiency conversion with electrolysis efficiency of 65 percent—same assumption applied all electrolysis technologies

** The additional cost assumption borrowed from Shaner et al.¹⁴² and used for grid electrolysis, solar PEV, wind (subsidized/unsubsidized), and hydropower. The calculation is corrected by capacity factor borrowing the assumption that the electrolysis system has fixed lifetime (e.g., 20 years). This cost includes all cost except for direct electricity cost: capital cost, maintenance cost, labor cost, installation cost, and others.

*** Result directly borrowed from Shaner et al.¹⁴³ using new electricity cost assumption and capacity factor assumption



The authors see that when the electricity price is very low (e.g., wind subsidized can be as low as \$14/MWh) with relatively lower capacity factor (35 percent instead of 45 percent in literature), additional cost (mostly capital cost) takes the majority in the cost breakdown. The authors' calculation on additional cost includes maintenance, labor, and others (borrowed from Lazard¹⁴⁴). Overall, the authors' calculation shows great consistency compared with other literature.

Capacity factor: capacity factor using the US national typical average for calculation. The authors noticed that there exists minor inconsistency of capacity factor assumption between electricity cost (LCOE in \$/MWh), which is borrowed from Lazard, and the capacity factor of electrolysis system. The authors' capacity factor is generally the lower end of Lazard's assumption¹⁴⁵ (e.g., utility scale solar PV: Lazard 21–32 percent, authors 20 percent; wind onshore: Lazard 38–55 percent, authors 35 percent). The authors took this inconsistency and carried on the calculation for two reasons: first, they are close enough to be compatible for calculation, and the authors' assumption on capacity factor is more realistic for actual operation. Second, the real facility expects issues like curtailment, drop of efficiency of electrolysis system, and operating at low power condition. Many of the authors' concerns like curtailment cannot be simply quantified, and the authors used relatively low capacity factor of electrolysis system for correction.

Electrolysis system cost: electrolysis system cost derived from Shaner et al.¹⁴⁶ after isolating the only variable considered for this study: the electricity cost. The key assumption driving the differences between different technologies is capacity factor, since the authors have assumed that the electrolysis system has a fixed lifetime. Lower capacity will result in less hydrogen production for the same capital investment, resulting in higher cost per unit of hydrogen. Compared with other literature, the authors' result was found to be reasonable: for high capacity factor grid electrolysis, electricity cost consists of more than two-thirds of the total cost, but the LCOH is lowest. The green hydrogen from hydropower has stayed relatively the same during the past few years, and the authors don't expect the hydropower cost to drop in the near future. The green hydrogen cost from wind and solar drops for 10–15 percent,¹⁴⁷ majorly driven by the drop of LOCE of wind and solar power instead of the electrolysis system.

Cost sensitivity: The authors believe this cost result is a good representation of national average, not necessarily for each case study. For example, ideal site locations for onshore wind and solar can provide capacity factor to be 50 percent and 30 percent, respectively, greatly lowering the cost of both LCOE and electrolysis systems. The prediction of electrolysis systems from various studies indicates that it has a potential drop for more than 50 percent by 2030.¹⁴⁸ All these factors can have a great impact on the hydrogen cost.

Although the authors expect the cost of green hydrogen to drop quickly in the future (except for hydropower), it is still much higher than hydrogen from SMR plus CCUS. The above calculation is a fair comparison for current cost structure of hydrogen production from various kinds of technologies.



A2. Electrification for Industrial Applications

Heating a Gas

Heating the gas form of a material has wide applications: SMR, ammonia production, methanol production, and blast furnace for preheating air. Infrared heating will fail for heating these gases since they cannot absorb infrared and convert infrared to heat. Still, heating another medium (e.g., container surfaces) to absorb infrared and then transfer the heat to gases can be used but with lower efficiency because of transmission and losses. The authors excluded infrared heating for gas-based reaction industry: ammonia, methanol production, and blast furnace for steel production.

Gaseous reaction, however, does not need the heating on the gases necessarily. Most reactions today require the presence of catalysts, where the reaction is triggered. Hot catalyst reaction surface and cold reaction gas design principle can theoretically reduce the energy consumption of the whole process, improving the overall thermal efficiency. It can also help reduce the capital cost since the high-pressure and high-temperature container can be replaced. This novel design is actually heating catalysts' (typically solids) surface instead of gases; therefore, it was not included here. Brand new heating equipment and reaction process design are required. Simple retrofit on existing plants is not applicable for this design principle.

Dielectric heating for water steam-containing gas mixture is theoretically viable. Represented by a microwave heating food, water can absorb a certain wavelength of electromagnetic wave much more efficiently than other materials (one to about two order of magnitude higher).¹⁴⁹ This can possibly be applied to water-containing reactions, such as SMR and methanol production. However, no literature was found to back up the industrial application, and the engineering limits of microwave heating gases (e.g. maximum temperature, maximum power, efficiency, and electromagnetic interference) are not clear. Dielectric heating may also interfere with radio transmission. Novel electrification on ammonia synthesis is now exploring electrochemical reactions, where heat is no longer required, and electricity serves as the only energy supply source. Some concepts to replace the classic Haber-Bosch process use new reactants (instead of nitrogen and hydrogen for reaction, they use water and nitrogen, or methane and nitrogen, etc.). These concepts required new facilities based on different chemistry; therefore, they are not discussed here.

The most possible electrification process for heating gases is based on resistance heating (indirect), which can provide temperature, heat flux, and energy absorbability via conduction and convection.

Heating a Liquid

Heating liquid is essential for steam generation, chemical reactions in liquid solutions (e.g., paper and pulp industry), and petrochemical distillations. Electromagnetic heating's frequency matters a lot for heating up liquid.

Based on liquid properties, water can be heated by microwave and resistive heating approaches. Dielectric heating on petrochemical requires more engineering details for frequency identification and special equipment designs.



Heating a Solid

Heating solid materials—steel, cement, gas, and others—is most common.

Both infrared (radiant) heating and resistance heating are theoretically viable. The actual viability depends on the temperature required for each industry.

Infrared can be directly absorbed by the solid materials. Although the infrared generation has efficiency lower than resistance heating, direct absorb can make the overall heating efficiency higher. But the heating depth can be a problem: penetration depth of infrared is limited with few millimeters, up to a few dozen for specific materials. Infrared absorb efficiency is generally inversely related to the depth of penetration: the more efficient it absorbs infrared (higher heating efficiency), the smaller the depth of penetration. Larger depth of penetration will lead to lower heating efficiency with more reflections.¹⁵⁰

Electric arc furnaces and induction furnaces for other nonferrous metals are commercially deployed already, majorly for secondary steelmaking and nonferrous metal processing. Microwave heating for lime calcination is proved feasible theoretically but is not applicable for scaled-up, practical plant design.¹⁵¹

A summary of the current status of some electrification methods on industrial process heat (see table A.2.1) is provided by the recently published paper by Schüwer et al.¹⁵²

Table A.2.1: Electric heating technology readiness level

Branch	Relevant technologies	TRL*	Developmental stage
Cross-sectional	Electric steam generation	7	Demonstration: Prototype test in operating environment
Paper and cardboard	Microwave (drying)	8	Demonstration: Qualified system with verification of functional capability in operating environment
Basic Chemistry	Miscellaneous	4	Technology development: Basic functional verification of technology/application in the laboratory
Glass, pottery	a) Inductive/indirect resistive b) Conductive	5, 9	a) Demonstration: Functional verification in application-relevant environment; b) Commercialisation: Successful commercial use of the system (small scale specialty glass troughs)
Cement, lime, bricks	Resistive	3	Technology development: Basic functional verification of individual elements of an application/technology
Iron & Steel	Conductive/ Inductive	9	Commercialization: (Full scale) successful commercial use of the system (secondary steel making)
Non-ferrous metals	a) Inductive/ Immersion Heater** b) Plasma heating/ Microwaves	9, 6	a) Commercialisation: For small holding furnaces already achieved today (induction furnaces and immersion heaters) b) Deomonstration: Coupling of thermal treatment and melting process (e.g. for paint stripping and melting of aluminum scrap), Plasma heating (demonstration project of Hydro in Norway)

*TRL = Technology Readiness Level;

**Immersion Heater = Ceramic tube of heating element with intergrated reistance heating elements



Some of the above technology is already being used (see table A.2.2): electric arc furnaces for basic metals (e.g., steel) and induction melting for machinery and equipment (e.g., shaping of metal). Some most commonly viable options (e.g., microwave heating, radio frequency heating, and infrared heating), however, are limited by engineering approaches and efficiency issues. They are physically possible but are still far from being market ready, especially in terms of costs.

Table A.2.2: Theoretical feasibility summary of electrification methods on selected industries¹⁵³

Industry sector	Infrared Heating	Resistance Heating	Ultraviolet Curing	Microwave Heating	Radio Frequency Heating	Induction/ Heating/ Hardening	Induction Melting	Electric Arc Furnace
Food Products				X	X			
Beverages								
Tobacco					X			
Textiles	X	X	X	X	X	X		
Wearing Apparel	X			X	X			
Leather Products	X			X	X			
Wood Products	X		X	X	X			
Paper & Paper products	X		X	X	X			
Printing				X	X			
Coke & refined petroleum				X	X			
Chemicals	X		X	X	X			
Pharmaceuticals			X	X	X			
Rubber & Plastics	X	X	X	X	X	X		
Non-metallic minerals	X	X	X	X	X	X		
Basic metals	X			X	X		X	X
Fabricated metal products	X	X	X	X	X	X		
Computers & electronics	X	X		X	X	X		
Electrical Equipment	X	X	X	X	X	X		
Machinery & equipment	X	X	X	X	X	X	X	
Motor vehicles	X	X	X	X	X	X		
Other transport equipment	X	X	X	X	X	X		
Furniture	X		X	X	X			
Other Manufacturing	X	X		X	X	X		
Repair & Installation	X	X	X			X		



Most engineering application details for all electrification pathways remain unsolved for now. Some research projects and pilot projects are investigating the possibility of electrification on industrial process heat. The actual heating efficiency (GJ/ton production) cannot be concluded here. Viability, efficiency, and temperature limit for electromagnetic heating are hard to explore since the situation changes extensively from case to case. The paper’s analysis of electrification heat cost increment is based on resistive heating, the most intuitive and direct way of electrification, which can satisfy all theoretical limitations: temperature, heat flux, and universal medium absorbability.

Please see Appendix B for more details about application of electrification on specific industries.

A3. Electricity Price Assumptions for Global Application

The authors’ study included two electricity price scenarios for electric heating (e.g., resistive heating), which is a good representation for US wholesale electricity. The authors also found it a good representation for the world’s major industrial countries. Here the authors provide additional information about the global electricity price; the price can be labeled as wholesale electricity or simply industrial power in different countries.

Table A.3.1: Industrial power supply price in major industrial countries other than the United States

Country	Price (\$/MWh)	Type	Reference
China	84	National average	Zhang ¹⁵⁴
China, Guangdong	86	Large-scale power rate	Zhang ¹⁵⁵
Germany	154	National average	Amelang ¹⁵⁶
EU	111	EU average	Amelang ¹⁵⁷
Japan	88	Day ahead 24 hours	Japan Electric Power eXchange ¹⁵⁸
UK	64	2018 average	Business Electricity Prices ¹⁵⁹
Indian	88	Tamil Nadu average	<i>India Briefing</i> ¹⁶⁰

The authors conclude that \$40–90/MWh can be a good representation for a lot of major economic entities, such as China, India, Japan, and the UK. The European Union, whose whole union’s average falls on the far end of \$60–120/MWh, can also be included. The authors’ two scenarios of electricity cost assumption, although based on the current level of the United States, are also a good representation to be applied globally.



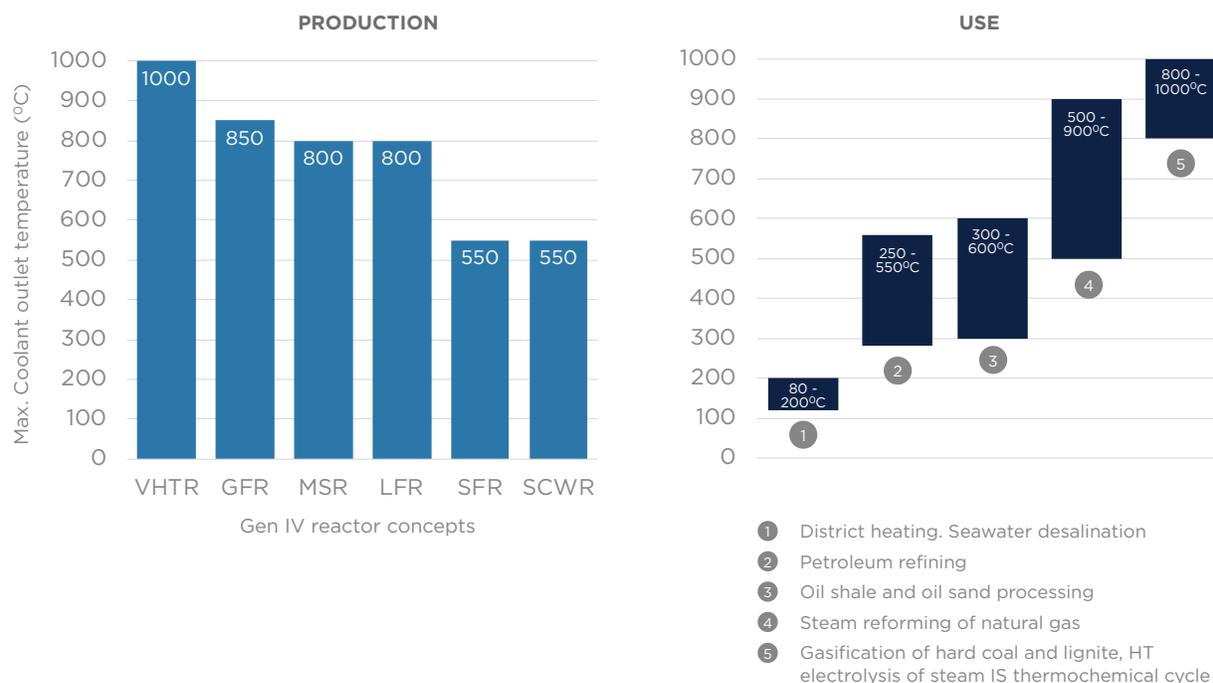
A4. Nuclear Novel Applications for Heat and Hydrogen Production

Nuclear for Heat

Using nuclear energy for industrial application is not a new idea; others include seawater desalination, district heating/cooling, coal liquids conversions, and chemical synthesis. Hydrogen production will be individually discussed later for this paper’s particular interests.

No impediment is expected to extract heat and steam from a conventional nuclear power plant, especially less than 200°C. However, less than 1 percent of the heat generated from nuclear reactors is used for nonelectric generation purposes, which is essentially negligible.

Figure A.4.1: Generation IV reactors temperature target and intended industrial applications¹⁶¹



Note: GFR - Gas cooled fast reactor; HT - high temperature; LFR - lead cooled fast reactor; MSR - molten salt reactor; SCWR - supercritical water cooled reactor; SFR - sodium cooled fast reactor; VHTR - very high temperature reactor.

As shown in figure A.4.1, generation IV reactors are opening various possible applications for heat supply and industrial applications. Here the authors focused on another major possible application of nuclear heat: petroleum, oil shale, and oil sand. It is a very broad and complex category that includes oil refining, oil shale and oil sand processing, crude oil desulfurization, petroleum refineries, and others. All the mentioned processes require temperatures of 200–600°C, typical for all generation IV reactors’ exit temperatures. Hydrogen production and other chemical production (e.g., ethylene) and coal processing (e.g., coal gasification and purification) will require much higher temperatures, typically 600–1,000°C.



A summary of industrial applications of nuclear heat is shown in table A.4.1.

Table A.4.1: Industrial applications of nuclear heat

Applications	Temperature	Remarks
High-pressure steam for enhanced oil recovery	200–300°C	Nuclear heat needed to be generated or transported to site
Oil upgrading and refining	less than 540°C	More than 70% energy demand for distillation and stabilization
Nuclear assisted ethanol production from biomass	about 180°C	Capable of reducing over 50% of fossil fuels required for the production of ethanol
Nuclear assisted methanol production from coal	920°C	Process is integrated with hydrogen production from syngas production
Ethylene production	750 to about 950°C	Hydrocarbon fraction together with polyethylene, higher olefins, and hydrogen
High-temperature preheating	N/A	For temperature requirement that nuclear heat is not qualified enough (e.g., more than 1,100°C for steel). It can preheat the target to lower temperature (e.g., 800°C for steel blast) and greatly reduce the overall fossil fuel requirement.

Source: International Atomic Energy Agency¹⁶²

Nuclear for Hydrogen Production (see figure A.4.2 and table A.4.2)

- Straightforward pathways (reaction principle is commercialized, nuclear heat integration required):

Nuclear assisted SMR: an ideal starting point for nuclear power to penetrate the hydrogen production market in the near and medium term. It uses the same SMR principle for hydrogen production using fossil fuel by changing only the heat source. The least technical improvement will be required (800°C required).

Nuclear assisted coal gasification: similar to nuclear assisted SMR. This is still based on existing fossil-fuel-to-hydrogen technology by switching the heat source to nuclear (950°C required).

Low-temperature electrolysis: using electricity from current water-cooled reactors for water electrolysis. The electrolysis process can be decoupled from the nuclear reactor, which can use electricity from other sources as well (about 90°C).

- Advanced pathways (reaction principle not commercialized):

High-temperature electrolysis (steam electrolysis): nuclear reactor provides both steam and electricity (i.e., both thermal and electrical energy) for electrolysis. The total energy demand required for electrolysis is reduced by heat, where heat is much cheaper than electricity. It requires 34 percent less electricity compared with low-temperature electrolysis (750 to about 950°C).



Thermochemical cycles: includes ultra-high-temperature direct water splitting, high-temperature two-step metal oxide oxidation-reduction reactions, and moderate-temperature three-step water splitting.

Thermochemical cycle technology is still at an early stage of development (temperature is case dependent).

Figure A.4.2: Summary of nuclear to hydrogen pathways¹⁶³

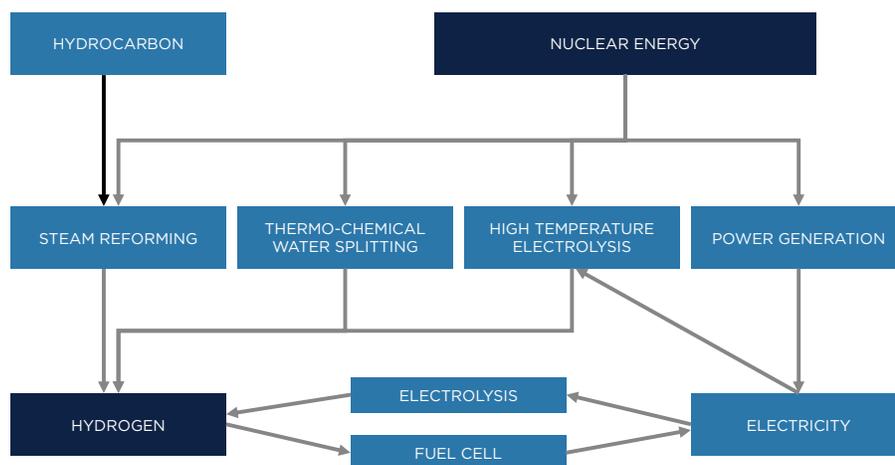


Table A.4.2: Hydrogen production with nuclear energy¹⁶⁴

Production method	Temperature	Form of energy required
Nuclear assisted SMR	800°C	Thermal
Nuclear assisted coal gasification	950°C	Thermal
Low-temperature electrolysis	90°C	Thermal plus electrical
High-temperature electrolysis	750–950°C	Thermal plus electrical
Thermochemical cycles	Pathway dependent, typical temperature 400–500°C	Thermal

A5. Small Modular Reactors

From the water consumption of a typical nuclear power plant, the cooling water need is not hard to satisfy. Roughly 11,000 tons/day of water will be needed for a 300 MWe small modular reactor, borrowing the 400 gallons of water per MWh for general cooling water consumption. A 2,200-ton steel plant with 120 MW heat input and 52 MW electrical power input will consume 166,320 tons/day of water. Some types of small modular reactors use gas cooling



(e.g., helium), metal (e.g., sodium), or molten salt for cooling, which is not subjected to water limitation. Typical water cooling of 300 MWe small modular reactors have a height of 20 m and diameter of 6 m. The small modular reactor can be deployed below the surface for better safety and space saving.

The Joint Institute for Strategic Energy Analysis’s study of thermal energy application of the small modular reactor¹⁶⁵ shows that it has great potential to be applied for industrial sectors, as shown in table A.5.1.

Table A.5.1: Thermal energy application of small modular reactors

Target industry	Process heat type/purpose	Temperature
Petroleum refineries, gasoline, diesel, and kerosene	Crude fractionator and heavy naphtha reformer	600°C
Basic chemical manufacturing	Primary reformer and steam	900°C
Ethyl alcohol manufacturing	Steam, drying, pretreatment, and distillation	Less than 300°C
Plastic material and resin manufacturing	Steam and distillation	291°C
Alkalies, sodium hydroxide, and chlorine manufacturing	Steam and drying	177°C
Nitrogenous fertilizer manufacturing	Primary steam reforming	850°C
Wet corn milling, starch, corn gluten feed/meal, corn oil	Steam and drying	177°C
Potash, soda, and borate mining	Steam, calciner, crystallizer, and dryer	300°C

The authors see a very small overlapping of small modular reactors’ application for thermal energy in industrial sectors that were analyzed (e.g., cement and steel), since small modular reactors cannot provide process temperature above 1,000°C.

A detailed process engineering model for petroleum refineries and major chemical manufacturing will be established in the future study. The results of the Joint Institute for Strategic Energy Analysis’s study coincide with the authors’ analysis results that nuclear in general (conventional, advanced, or small modular reactor) is not feasible for material productions such as cement, steel, and glass.

A6. P2G and Biogas

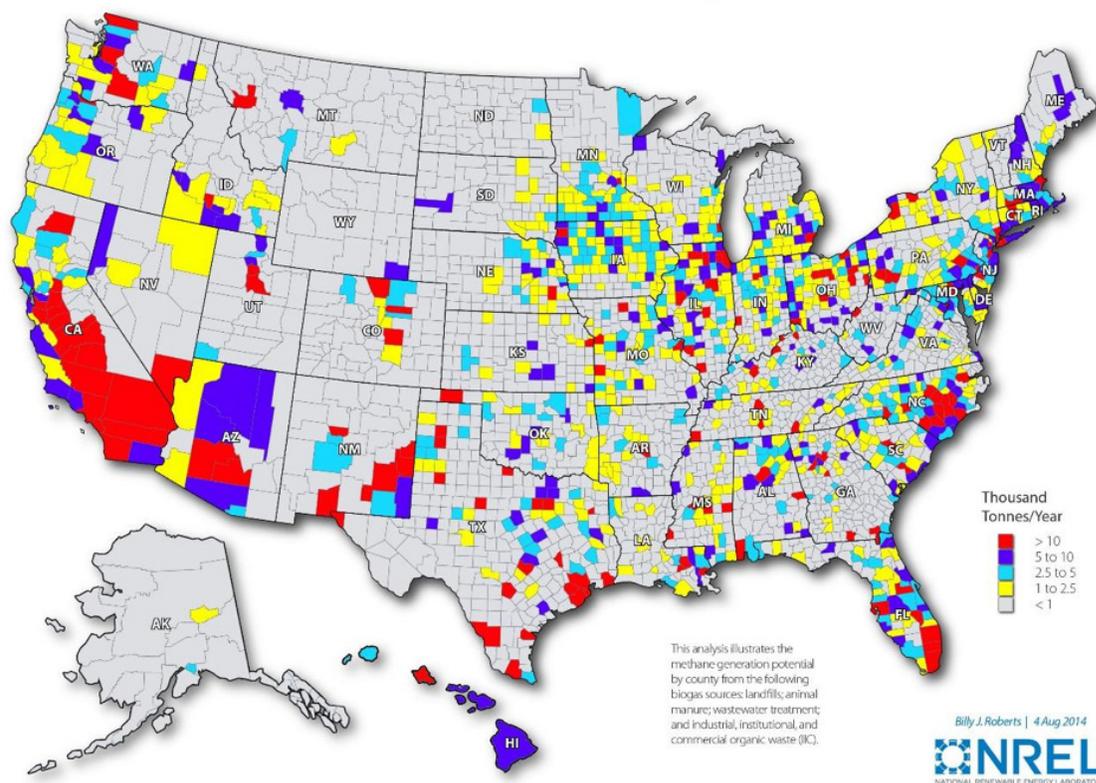
For Power2Methane, the overall system energy efficiency is 35 percent (47 percent electrolysis for hydrogen and 73 percent for methanation at 377°C) with start-up time of 40 minutes (standstill to maximum capacity). It can respond to 4 minutes of electricity supply control, and therefore, is applicable for the dynamic load profiles, such as intermittent power from wind and solar.



The discussion of P2G is usually coupled with renewable generation, since converting electricity generated from fossil fuel is far from carbon neutral (see Appendix A.6). The ability to follow dynamic load of wind and solar is potentially valuable to be used as an energy storage method, although the gas (both hydrogen or methane) may not go back to the grid finally. The cost of gases from P2G process is expected to drop because of improvement of electrolysis efficiency (up to 80 percent), lower capital cost of electrolyzer system (\$/MW), and storage cost of hydrogen (\$/MWh). If converted to methane, infrastructure can be merged directly with natural gas, since P2G is proved to be able to provide pipeline standard methane subjected to combustion and chemical reaction. If P2G is a form of hydrogen, additional infrastructure is anticipated since the study shows that only at very limited conditions, hydrogen storage, transportation, and application can be deployed directly via natural gas infrastructure.¹⁶⁶

The US biogas potential is provided by the National Renewable Energy Laboratory (see figure A.6.1), which is shown to have a great overlapping with methane consumptions (e.g., economic development).

Figure A.6.1: Biogas generation potential of the United States¹⁶⁷



A7. Carbon Footprint of Low-Carbon Heat, Initial Results

Table A.7.1: Direct carbon intensity of heat*

Heat source	Carbon intensity (CO ₂ kg/GJ)
CH4	50.33 ¹⁶⁸
Coal	90.38 ¹⁶⁹
Diesel	69.34 ¹⁷⁰
Hydrogen SMR without CCUS	100.64 ¹⁷¹
Hydrogen SMR 53% CCUS	47.29
Hydrogen SMR 64% CCUS	36.22
Hydrogen SMR 89% CCUS	11.06
Green hydrogen	Low**
Nuclear	Low**
Electric heating, US average	127.78
Electric heating, CH4 generation	110.90
Electric heating, California	61.11
Electric heating, low carbon (wind, nuclear, and hydropower)	0.55 to about 11.3 ¹⁷² ***
Electric heating, low carbon (solar PV)	3.6 to about 36.1 ¹⁷³ ***

* This is not a result of full LCA analysis except for low-carbon electricity (from literature). It just represents a quick understanding of relative carbon intensity for each type of fuel—for example, fossil fuel’s carbon intensity is from direct burning, and hydrogen’s carbon intensity is from production processes (not including the carbon footprint of equipment, transportation, etc.).

** This number is hardly understood since LCA is not applied here. The number should be very low and essentially carbon neutral compared with other technologies.

*** This particular result is provided by a range instead of a single value, which marks uncertainty of carbon intensity revealed from the LCA analysis of literature. Although hugely different (in order of magnitude), green electricity is still the lowest in terms of carbon intensity, even compared with hydrogen with 89 percent CCUS.

Full LCA analysis for application is so far hard to obtain, since many technology details are not available (e.g., electric heating and nuclear heating), so the authors put the LCA analysis after the process engineering details, which will be performed in the future.

Although not very accurate, the result (see table A.7.1) still shows an important point: low-carbon heat source is sometimes not really low carbon. Production of hydrogen is very carbon intensive, and a 53 percent carbon capture rate with CCUS is just barely enough to bring it down to roughly natural gas’s direct carbon intensive level. Hydrogen production using SMR with 89 percent CCUS is close to carbon neutral but is only one-fifth of natural gas’s level. Electric heating so far is far from carbon neutral: the US average carbon intensity



is 150 percent more carbon intensive than natural gas, and even one of the cleanest grids in California is 20 percent more carbon intensive than natural gas. However, as mentioned before, this result is far from conclusive. Full LCA may reveal different aspects, and here it is just per GJ consideration of direct emission. Different heat sources will lead to very different technology, and therefore, very different designs and energy efficiency, whose result have to be discussed after process engineering models are established.

The order of magnitude difference of carbon intensity for green electricity is an intrinsic nature of those generation methods. Since the absolute value of carbon intensity is superlow, a lot of factors can greatly affect its carbon intensity: recyclable issues, local manufacture conditions (e.g., source of electricity and materials), transportation, etc. Wind, nuclear, and hydropower have relatively similar results and are discussed together, while solar PV is discussed separately. But overall, green electricity is definitely among the greenest options of low-carbon heat.

Here the authors do not present the literature's analysis on biomass on purpose since the range has a two order of magnitude difference, making it both the best and the worst choice of low-carbon heat. This result is meaningless to be discussed with such a high viability. The authors intend to perform a case-by-case study in the future with LCA analysis performed.



APPENDIX B: SPECIFIC INDUSTRIAL APPLICATIONS

B1. Assumption Summary

Table B.1.1: Products cost and original fuel assumptions

Industry	Product	Original price (\$/ton)	Original heat type	Original heat price	Original specific heat price (\$/GJ)
Cement	Clinker	40	Coal	75 \$/ton	2.41
Iron and steel	Pig iron	400	Coal	75 \$/ton	2.41
Glass	Raw glass	300	Natural gas	3.5 \$/MMBTU	3.32
Ammonia	Ammonia	500	Natural gas	3.5 \$/MMBTU	3.32
Methanol	Methanol	432	Natural gas	3.5 \$/MMBTU	3.32

Table B.1.2: Products energy and carbon intensity assumptions

Industry	Process for heat replacement	Heat intensity (GJ/ton)	Heat carbon intensity (ton/ton)	Total carbon intensity (ton/ton)	Heat emission fraction
Cement	Clinker kiln	3,444 ¹⁷⁴	0.39 ¹⁷⁵	0.66 ¹⁷⁶	59%
Iron and steel	Blast furnace	7,592 ¹⁷⁷	0.9 ¹⁷⁸	1.9 ¹⁷⁹	47%
Glass	Glass furnace	6,858 ¹⁸⁰	0.37 ¹⁸¹	0.53 ¹⁸²	69%
Ammonia	Haber-Bosch process and SMR	7,100 ¹⁸³	0.7 ¹⁸⁴	1.9 ¹⁸⁵	37%
Methanol	Syngas synthesis and SMR	15,400 ¹⁸⁶	0.31 ¹⁸⁷	0.54 ¹⁸⁸	57%

Table B.1.2 shows that high-quality heat-related emission takes roughly half the total emission, coinciding with the big picture that 11 percent out of 21 percent industrial carbon emission come from heat production. For cement, glass, ammonia, and methanol, heat replacement for identified processes should take the overwhelming majority of high-quality heat input. For iron and steel, only the blast furnace is identified, while coke used as a reduction agent is not included. But coke as a reduction agent for the reaction will release heat and support the high temperature as well. Energy emission fraction for blast furnace only is not a 100 percent representation for energy input, making the energy emission fraction and cost fraction for energy a bit lower than actual (see figures B.3).



B2. Clinker Production Electrification Calculation

The analysis is based on rotary clinker kiln with preheater (dry process). The key specifications are shown in table B.2.1.¹⁸⁹

Table B.2.1: Dry process rotary clinker kiln specifications

Category	Specifications
Reactants	Calcium carbonate/silica minerals
Current fuel	Coal, heavy oil, natural gas, etc.
Temperature	Peak 1,450°C, most parts 1,000 to about 1,200°C
Heat transfer type	Radiant heat transfer (prefer bright and hot flame)
Dry process	Preheaters (heat from kiln gas and cooled clinker)
Flame temperature	Coal 2,000°C and natural gas 1,900°C Coal is better in terms of heat quality; it's brighter and hotter.

Table B.2.2: Resistance heating viability calculation for clinker kiln geometry

Category	Specifications
Total energy input	110 MW
Heat portion	56.9%
Heat power input	62.6 MW
Preheated temp	1,000°C
Material peak temp	1,450°C
Diameter	4.2 m
Length	59 m
Total resistive area	817 m ²
Heating power/m ²	Take the max: 90 kW/m ² (at 1,600°C) ¹⁹⁰
Max heating power within geometry	73.53 MW (117% of requirement)

The authors can see that the electrification of cement clinker kiln using resistive heating is only marginally feasible: the existing geometry availability of the clinker kiln can provide just enough heat required using combustion. A lot of constraints are subjected to the electrification retrofit: heating efficiency and heat loss because of new technology, process time, heat transfer coefficient, and others. These factors will be considered in the future study with detailed process engineering models.



Here the authors want to point out that electrification with resistive heating is not guaranteed to be feasible for existing plant design. Geometry limitation for resistive heating generation remains a problem to solve since the simple calculation is showing that the feasibility is barely marginal.

Literature¹⁹¹ shows that microwave hybrid processing of lime for cement, steel, and glass industries is theoretically possible but not yet feasible for scaled-up production size of application. Microwave assisted technology has the potential to reduce energy consumption by 25 percent and process time by 34 percent. Commercialization of this technology will require more pilot scale calcining demonstration with the involvement of kiln producers and microwave equipment producers. Although not the same, this literature still demonstrates the possibility of using direct heating method (electric resistive heating is indirect since it needs heat transfer to the heating target), but it is not yet proved commercialized. The authors excluded direct electric heating of cement clinker production. So far, this pathway has proved not applicable in production scaled.

B3. Cost Fraction from Heat

The figures below show the cost fraction associated with heat while changing the heat source to potentially low-carbon heat sources. Originally, the heat cost fraction for all industries should be below 20 percent in general, depending on the price of fuel. But low-carbon heat sources will make this fraction greatly larger, typically more than 20 percent and in some cases over 50 percent. This will make the price of products extremely sensitive to heat prices and create uncertainties that manufacturers would be reluctant to switch to low-carbon heat sources since it's much less stable and predictable. This cost fraction result is just a primary result, and details of cost still remain a challenge and will be addressed after a process engineering model is established.

Figure B.3.1: Cost fraction increase for heat production: H₂ SMR with 53% CCUS

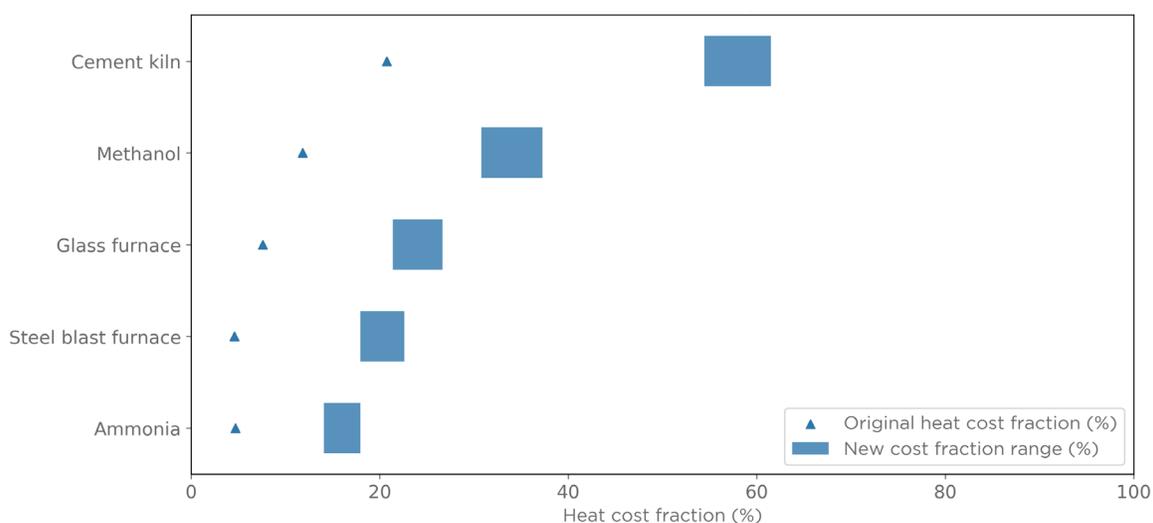


Figure B.3.2: Cost fraction increase for heat production: H₂ SMR with 89% CCUS

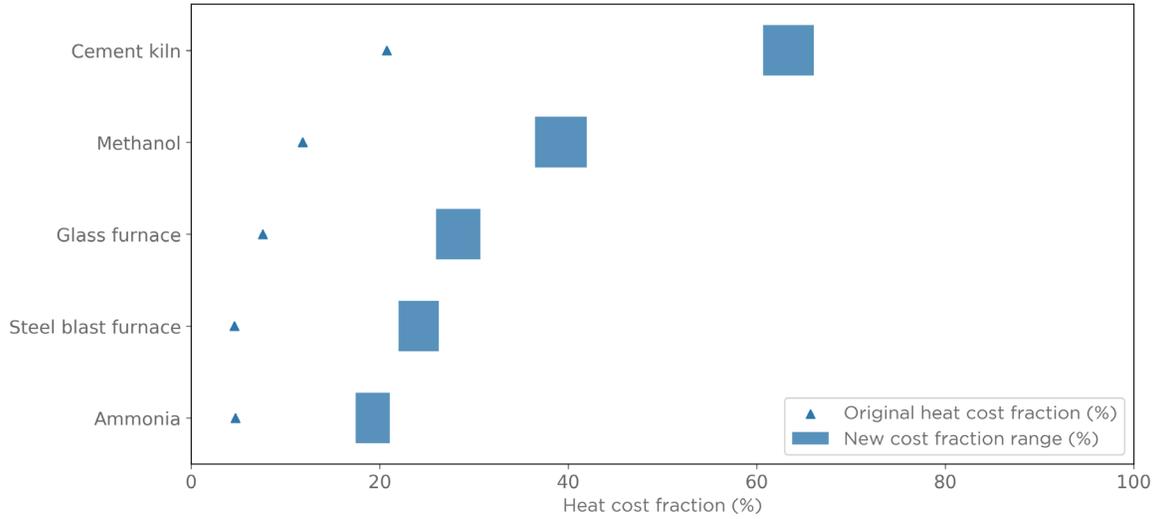


Figure B.3.3: Cost fraction increase for heat production: H₂ renewable

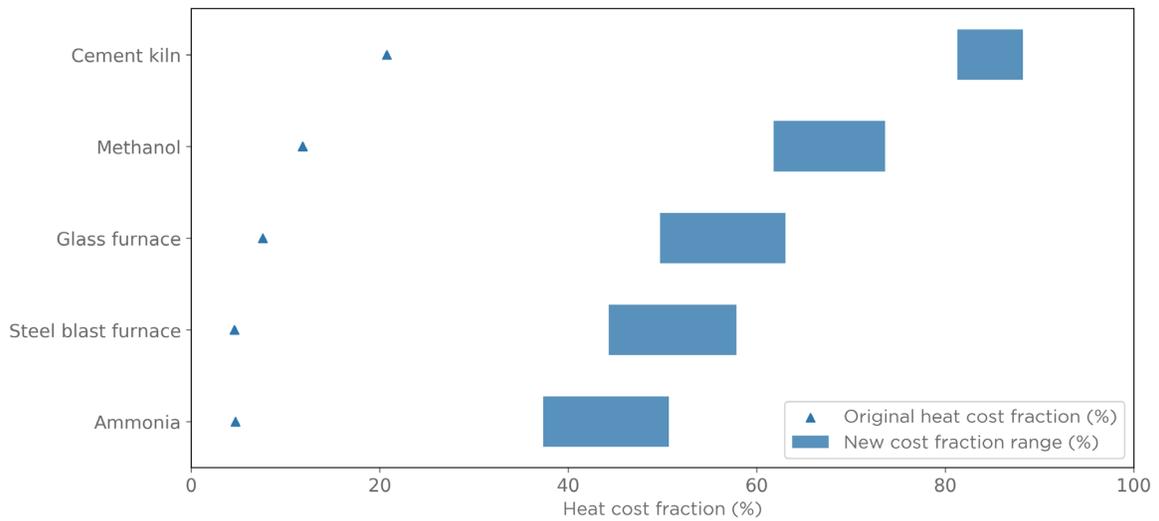


Figure B.3.4: Cost fraction increase for heat production: Electricity, \$40-\$90/MWh

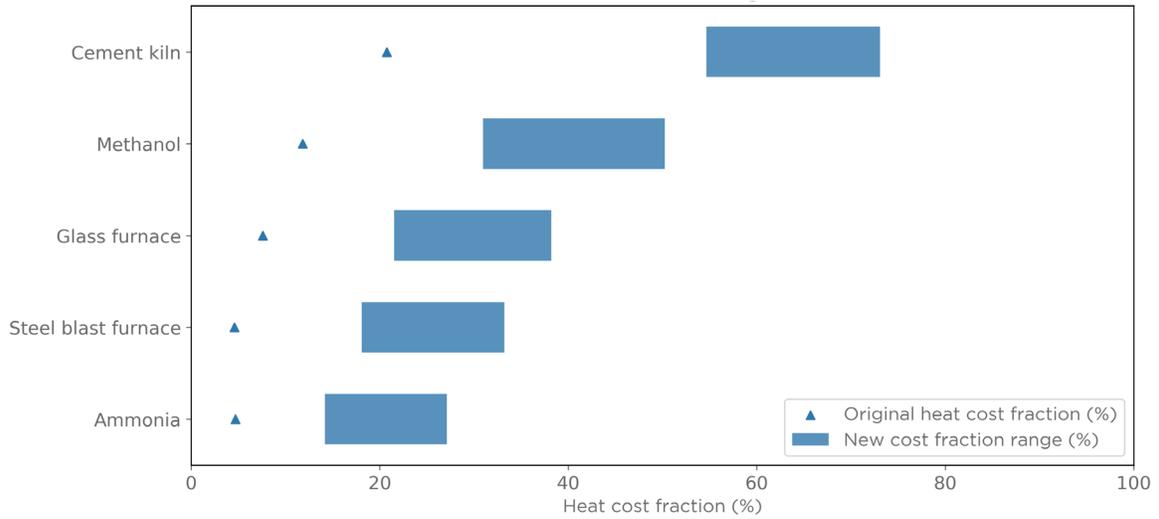


Figure B.3.5: Cost fraction increase for heat production: Electricity, \$60-\$120/MWh

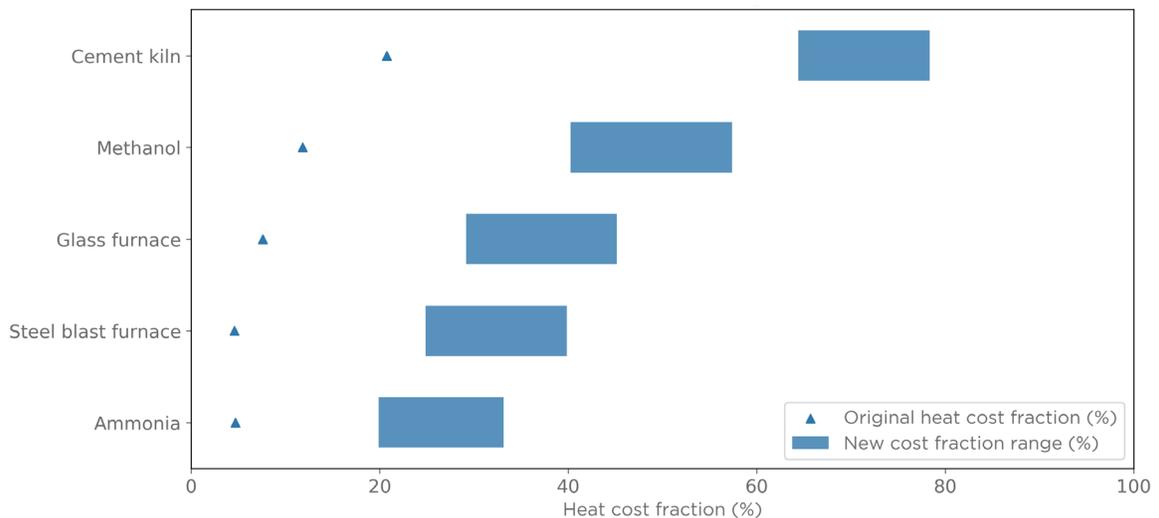


Figure B.3.6: Cost fraction increase for heat production: Biomass

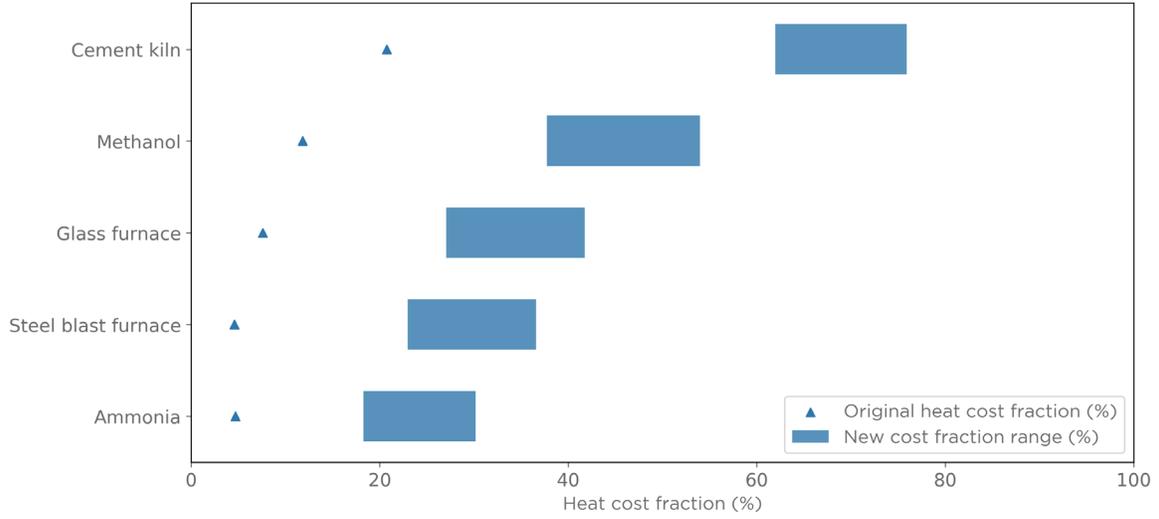


Figure B.3.7: Cost fraction increase for heat production: Advanced nuclear

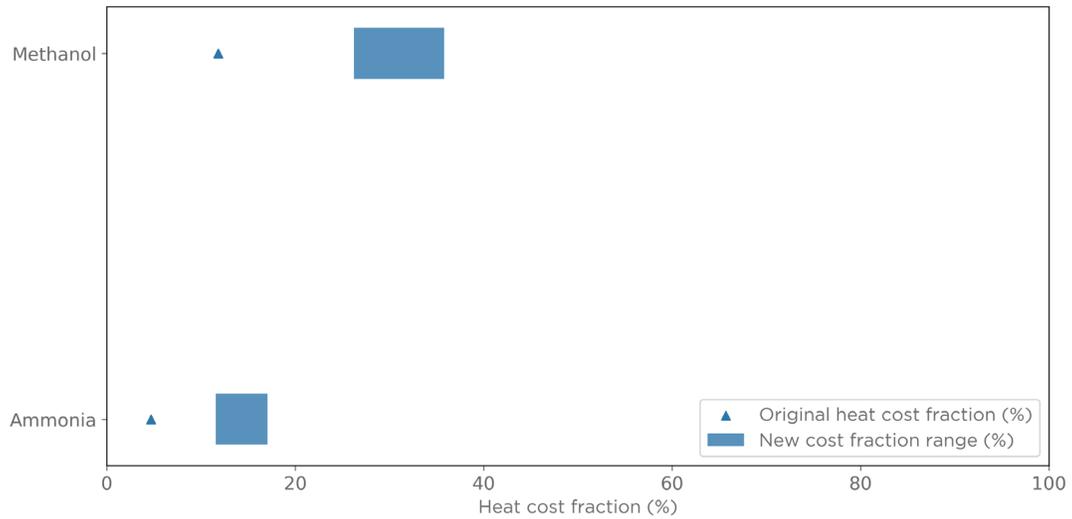
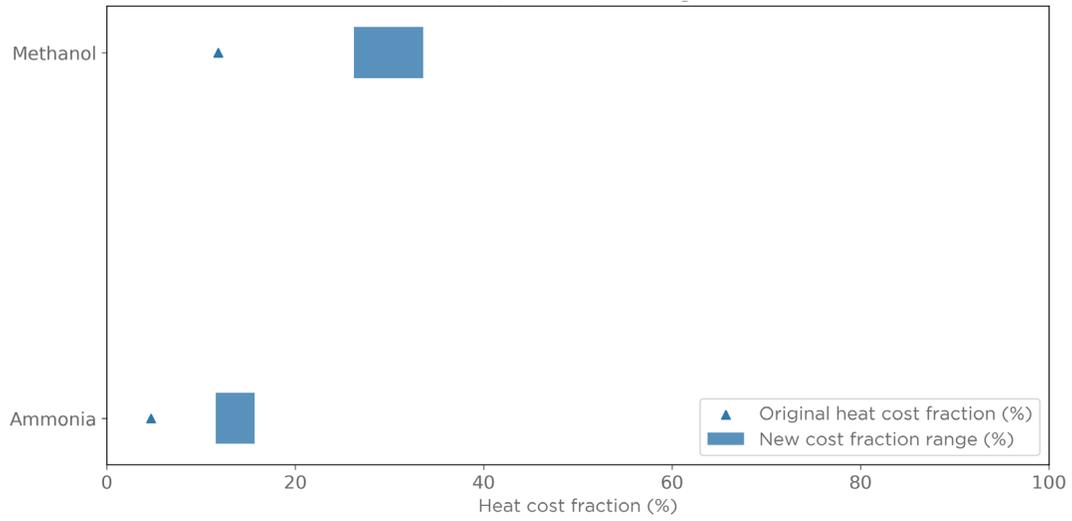


Figure B.3.8: Cost fraction increase for heat production: H₂ SMR without CCUS



APPENDIX C: KEY ACRONYMS AND UNITS

BWR—boiling water reactor (nuclear)
CCUS—carbon capture, use, and storage
CO₂—carbon dioxide
CSP—concentrated solar power
DRI—direct reduction of iron (steel)
FBR—fast breeder reactor (nuclear)
FNR—fast neutron reactor (nuclear)
GHG—greenhouse gas
LCA—life-cycle assessment
LCOE—levelized cost of electricity
LCOH—levelized cost of hydrogen
LED—light-emitting diode
LHV—lower heating value
OECD—Organization for Economic Cooperation and Development
P2G—power to gas
PEC—photoelectrochemical (water splitting)
PEM—proton exchange membrane (water splitting)
PWR—pressurized water reactor (nuclear)
SMR—steam methane reforming

Units

GJ—gigajoule
GW—gigawatt
kW—kilowatt
kWh—kilowatt-hour
MW—megawatt
MWh—megawatt-hour



NOTES

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