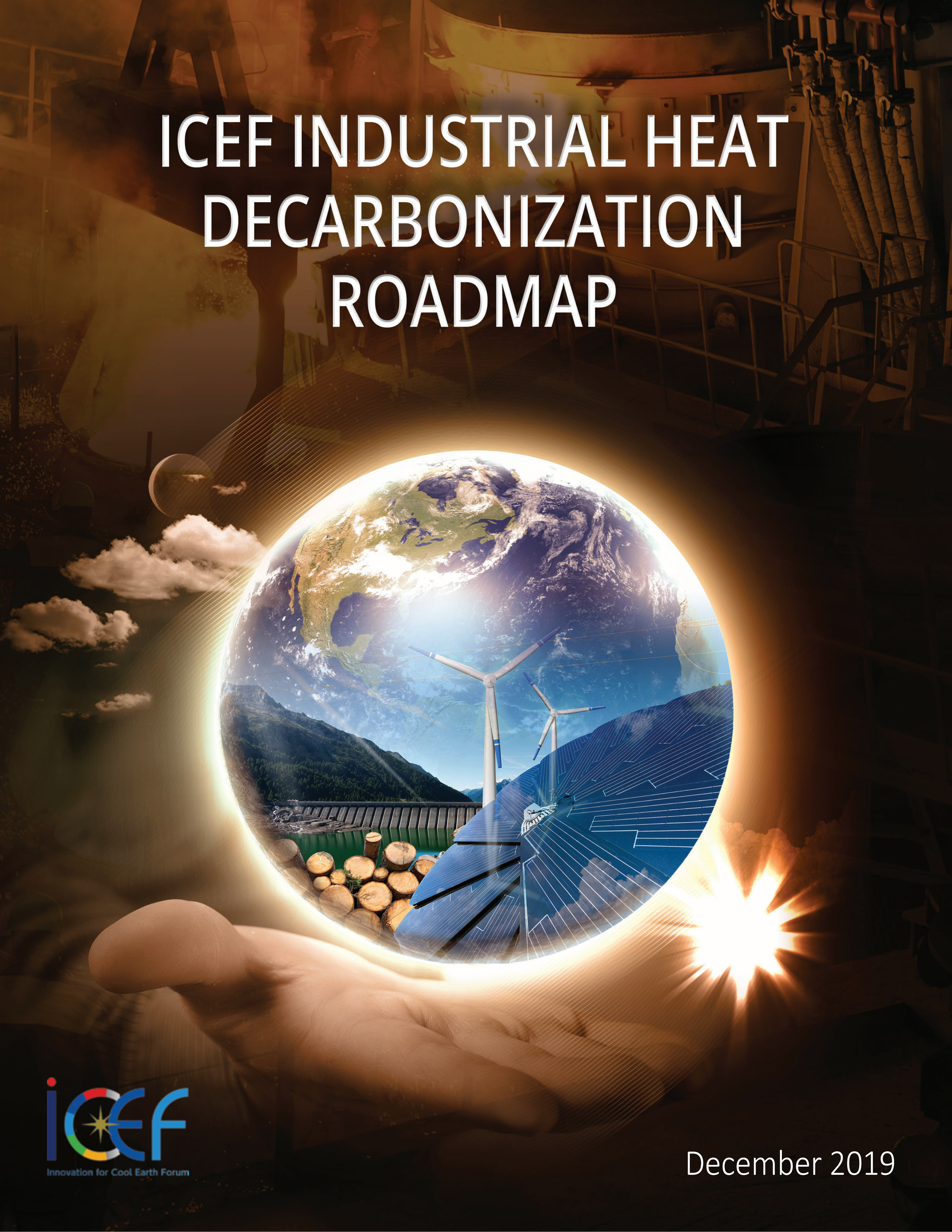
ICEF INDUSTRIAL HEAT DECARBONIZATION ROADMAP



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EXECUTIVE SUMMARY

INTRODUCTION

Roughly 10% of global greenhouse gas (GHG) emissions come from the production of heat for industrial processes—more than cars and planes combined. Decarbonizing industrial heat production will be essential to meeting the Paris Agreement goals. This topic has received far less attention than decarbonization of the power, transport or building sectors.

Most heavy industries require enormous quantities of heat. In many cases (including the cement, iron and steel, and chemical industries), core processes involve smelting ore, breaking strong chemical bonds and/or increasing the energy content of products.

Today, almost all industrial heat is provided by combustion of coal, oil or natural gas. These fossil fuels provide the high temperatures, continuous operation and reliability many industrial processes require. Any options for decarbonizing industrial heat must match these capabilities or be part of a broader change in industrial processes.

Options to provide low-carbon heat for industry include hydrogen; biomass; electrification; carbon capture, use and storage (CCUS); nuclear power; and concentrated solar power (CSP). Few if any of these options are well developed in the context of industrial heat production.

Several characteristics of heavy industries create challenges in decarbonizing industrial heat production. First, industrial facilities are long-lived capital stock, lasting decades. Second, many industrial products are globally traded commodities, subject to significant loss of market share due to small increases in production costs. Third, many industrial facilities are far from renewable resources such as biomass or abundant solar radiation, limiting decarbonization options. Fourth, many governments view these industries as core national assets, affecting national security and the balance of trade.

This Roadmap explores the challenge of industrial heat decarbonization. It is intended to be an initial, "1.0" analysis of the topic. After providing general background, we discuss four technological approaches for providing low-carbon industrial heat: hydrogen, biomass, electrification and CCUS. We next examine decarbonizing heat production in the cement, iron and steel, and chemical industries. We then turn to policy options and an innovation agenda. We close with findings and recommendations.

TECHNOLOGY OPTIONS FOR LOW-CARBON INDUSTRIAL HEAT

Hydrogen.

Hydrogen combustion produces heat without carbon dioxide (CO_2) emissions. Hydrogen can substitute for coal, oil and gas as a fuel in some industrial processes, reducing on-site emissions. However the production of hydrogen may involve substantial CO_2 emissions, reducing or eliminating the CO_2 benefits of switching to hydrogen. Low-carbon production of hydrogen is thus essential for hydrogen to play a role in decarbonizing industrial heat.

The most common hydrogen production process today is steam methane reforming ("gray" hydrogen), which has significant CO_2 emissions. This can be substantially decarbonized by adding CCUS ("blue" hydrogen), reducing the carbon footprint by 55-90% or more. Low-carbon hydrogen can also be made through electrolysis using zero-carbon power ("green" hydrogen).

Hydrogen could be used in many existing industrial heating systems with small changes, especially for chemical synthesis. Issues such as sensors, controls, corrosion and embrittlement appear resolvable with minor costs and system modifications. Blue hydrogen would add modest costs to production of hydrogen and raw industrial products (20-50% increase). Green hydrogen would add substantial costs (200-400% increase). As costs for firm renewable power decrease in the future, green hydrogen may become more attractive and could take advantage of infrastructure originally installed to use blue hydrogen.

Biomass.

Biomass provides considerable heat when burned. Biomass can be converted to useful intermediates such as biomethane, biodiesel and bio-char, and provides a carbon source and chemical reductant important in some industries. Biomass has the potential to deliver net low-carbon heat, since biomass can regrow, absorbing CO_2 released during combustion. However land use changes related to biomass harvesting can reduce or eliminate these CO_2 benefits. Transport and processing of biomass, as well as use of fertilizer, can also reduce the GHG benefits of biomass combustion.

Approximately 200-500 EJ/y of sustainably produced biomass can be available by 2050, similar to the projected global industrial energy demand of 330 EJ/y in 2040. Nevertheless, scaling biomass sufficiently to play a significant role in industrial heat production would be a challenge. Biomass is more geographically diverse and expensive to collect and transport than fossil fuels. Woody biomass has about half the energy density and considerably lower bulk density (before grinding) than coal. There are competing demands for biomass in a low-carbon future, including as vehicle fuel, dispatchable electricity and means of negative emissions. Despite these challenges, biomass has the potential to contribute to low-carbon heat for industry in some applications.

Electrification.

A wide variety of existing and emerging electrical technologies can provide high-temperature industrial process heat, including resistance heating, microwaves, induction and electric arc furnaces. Electrical heating has high controllability of temperature and duration of heat application, relatively low maintenance, and inherently low emissions when powered by low-carbon electricity. However, reliable electricity in industrially relevant quantities is not always available and in general is higher cost than combustion-based technologies.

The installation of electric process heat systems often requires more changes to existing equipment than switching to alternate combustion-based fuels (such as hydrogen or biomass). It may also require substantial plant redesign. The use of electricity in industrial process heat applications can place major burdens on the electric grid. While some optimization such as participation in demand-side management (DSM) systems is possible, this is limited in practice and major grid infrastructure upgrades are needed for large-scale industrial electrification.

Carbon capture, use and storage (CCUS).

CCUS has an important role to play in reducing emissions from production of industrial heat. The building blocks of CCUS include separation of CO_2 from combustion products or hydrocarbon fuels, transportation of CO_2 to a suitable storage site (or location where it is used), and geologic storage of CO_2 or conversion of CO_2 into a range of products (e.g., carbonate minerals, chemicals and fuels). CCUS is attractive because it usually does not require wholesale changes to the underlying industrial processes.

Experience with CCUS has grown considerably since 1996, when the first “purpose built” project began storing CO_2 captured from a gas processing platform deep under the North Sea. Today, CCUS projects are capturing CO_2 that would have otherwise been emitted from power generation, ethanol fermentation, gas separation, iron and steelmaking, and hydrogen production. CO_2 capture for industrial processes—particularly cement and steel—requires further development through demonstration projects at scale. Infrastructure is needed to transport and geologically store large volumes of CO_2.

SECTORAL STUDIES

Cement.

Cement provides the foundation for the built environment. Currently, over 4 Gt of cement are produced annually, resulting in more than 2 Gt per year of CO_2 emissions. CO_2 emissions from cement manufacturing result not only from high-temperature heat—nearly 1,500 °C in the cement kiln—but also from decomposition of limestone ($CaCO_3$). Many strategies for reducing these emissions have been considered, including fuel switching in conventional cement making, fundamental changes in the composition of cement and more efficient use of concrete in design.

Substitution of lower-carbon-intensity fuels for coal is already having a substantial impact in the cement sector. This could be furthered by increased use of biomass-based wastes and sustainable biofuels. However, given the limited supply of sustainable biomass and competition that may emerge for its different uses, this may not be cost-effective in large quantities. CCUS appears to be an important option for reducing emissions from cement production.

Iron and steel.

The iron and steel sector is one of the largest in the world, responsible for 7-9% of global direct emissions from fossil fuel. New steel production primarily uses a blast furnace to convert iron ore to pig iron, followed by a basic oxygen furnace to convert pig iron to steel. This process is emissions-intensive, with most emissions coming from the blast furnace. Electric arc furnaces convert recycled steel and iron from other processes to liquid steel in a far less emissions-intensive manner but are limited by availability of recycled material.

In blast furnaces, process heat is provided by combustion of coke. Coke also provides carbon as a reductant, acts as structural support to hold the ore burden, and provides porosity for rising hot gas and sinking molten iron. Because of these multiple roles, directly replacing coke combustion with an alternative source of process heat is not practical. Options for reducing process-heat-related emissions from blast furnaces include reducing coke through hydrogen co-injection and plasma torch super-heating of hot blast air. Direct-reduced iron (DRI) and smelting reduction iron can also be used in blast or arc furnaces to reduce emissions. Biomass-nugget smelting, hydrogen-reduction iron making, and electrolytic steel production also offer alternatives. CCUS can significantly reduce process-heat-related emissions when applied to flue gas at an integrated steel mill, blast furnace gas, or DRI and smelting reduction processes.

Chemicals.

The global chemical industry is roughly 3% of global CO_2 emissions. Energy demand for chemicals is greater than for either cement or steel, reflecting enormous heat consumption. Chemical facilities use a wide set of feedstocks and fuels, consuming natural gas, natural gas liquids, heavy hydrocarbons (e.g., bitumen, asphalt), coal and hydrogen. Facilities are highly complex with a wide range of chemical-production processes. Many reactions require fit-for-purpose reactors that cannot readily be replaced. A concern specific to the chemical industry is the broad distribution of heat sources, which can include dozens or hundreds of small emissions sources such as burners, furnaces and boilers.

Hydrogen (blue or green) appears to be the most ready substitute for current fossil fuel heat sources, in large part because many chemical facilities use predominantly gaseous fuels for heat production. CCUS retrofits may cost less than switching to hydrogen in some instances, although capturing CO_2 from many distributed heat sources may prove challenging. Efficiency improvements provide near-term opportunities to reduce emissions. In the future, electrification may prove workable, especially for straightforward substitutions such as steam production. To achieve widespread electrification, low-carbon electric power would need to be much cheaper and more readily available, and novel systems of heat deposition would require development and demonstration.

INNOVATION

The greatest challenge in innovation for industrial heat is the extreme diversity of processes that require carbon-free energy. Systematic changes across the economy, such as switching from methane to hydrogen in gas pipelines, will be important options, but there is currently no analytical basis on which to compare options. Detailed and cross-cutting analysis of the benefits and costs of zero-carbon fuels, biomass, and hybrid systems involving CCUS and direct air capture are needed before nations can commit to wholesale industrial changes.

The most immediate pathway to decarbonizing industrial heat is likely to be one that incrementally reduces emissions, with relatively small changes from options like more efficient heat application, reduced carbon footprint of fuels, and hybrids involving partial carbon capture and storage (CCS). It is important to evaluate and develop these partial pathways in concert with those that completely transform industrial processes. Zero-carbon fuels are likely to be an important element of such transitions. Global transport of hydrogen and biomass needs to be evaluated for both economic and climate impacts to determine if that is an approach that can overcome regional shortages in those two fuels. The safety and operational issues of zero-carbon fuels (flame visibility for hydrogen, methane leakage for renewable natural gas and food/ecosystem tradeoffs for biofuels) need to be carefully evaluated.

High capital costs are likely to be a major barrier to the transition to zero-carbon industrial heat sources. Finally, the costs of completely decarbonizing by utilizing direct air capture need to be evaluated for industries that have achieved partial decarbonization but face massive capital expenditures to completely eliminate their carbon emissions.

POLICY

Policy tools are essential for decarbonizing industrial heat, both in the short- and long-term.

Market forces alone are insufficient, since CO_2 emitters do not bear the full costs of their emissions. Government policies are essential. Many policy tools are available to help with decarbonizing industrial heat. These include:

1. **Government support for research and development (R&D).** National governments spend roughly $15 billion annually on R&D for clean energy technologies. These programs have played important roles in the development of countless technologies in recent decades. Increased R&D funding on industrial heat decarbonization is essential.
2. **Government procurement.** Governments are major purchasers of steel, cement, chemicals and other products that require heat in the manufacturing process. Procurement standards that give preferences to products with the lowest embedded carbon content could drive significant changes in industrial behavior.
3. **Fiscal subsidies.** Decarbonizing industrial heat will impose costs on affected businesses. Government policies can help to reduce those costs with fiscal subsidies. These can take several forms, including tax incentives, grants, loan guarantees, feed-in-tariffs and contracts for differences.
4. **Infrastructure development.** The transition to low carbon industrial heat may require new infrastructure (such as electric transmission lines or hydrogen pipelines). Governments can play a central role in facilitating the development of such infrastructure through permitting, financing and other measures.
5. **Carbon prices.** A price on CO_2 emissions, whether through an emissions-trading program or tax mechanism, provides emitters with an important incentive to cut emissions. The carbon prices that might be needed to induce a transition from fossil fuels for industrial heat production are unclear.
6. **Carbon tariffs.** Carbon tariffs (sometimes called "carbon border-tax adjustments") are a tool for addressing international competitiveness concerns. A country that requires its manufacturers to transition to low-carbon industrial heat could tax imports of relevant products from countries that fail to do so.
7. **Mandates.** Governments could prohibit the use of fossil fuels or require the use of low-carbon technologies for generating heat in certain industrial sectors.
8. **Voluntary industry associations.** Industry associations such as World Steel Association, World Petroleum Council, World Cement Association and World Business Council on Sustainable Development can help develop methods and standards for decarbonizing industrial heat. They can play an important role in information-sharing on such topics.
9. **Clean Energy Ministerial.** The Clean Energy Ministerial is a global forum where major economies work together to share best practices and promote policies and programs that encourage and facilitate the transition to a global clean energy economy. A Clean Energy Ministerial initiative on industrial heat decarbonization could help to share best practices and accelerate their adoption.

FINDINGS AND RECOMMENDATIONS

Decarbonizing industrial heat production will require innovating in multiple sectors. Our key findings and recommendations include:

- **Finding 1:** Emissions from industrial heat production limit progress on climate goals.
- **Finding 2:** The operational requirements and commercial realities of many industries limit opportunities for decarbonization.
- **Finding 3:** There are few options today for low-carbon heat generation for industry.
- **Finding 4:** Existing options face challenges based on price, performance and viability.
- **Finding 5:** There appear to be many pathways to improving cost, performance and viability of low-carbon industrial heat options.
- **Finding 6:** Many policy options exist that could improve the speed and magnitude of industrial

decarbonization and deployment of low-carbon alternative heat systems.

- **Recommendation 1:** Key stakeholders should prioritize industrial heat production as a key element of any climate mitigation strategy.
- **Recommendation 2:** Industry-specific analytical frameworks and innovation agendas are essential. Governments and companies together should develop new initiatives and R&D programs to focus on industrial sector decarbonization with a focus on heat supplies.
- **Recommendation 3:** Governments should identify and implement a set of policy actions to accelerate and support industrial decarbonization, starting with "buy clean" procurement.

Final thoughts

This Roadmap is an initial foray into this extremely important and complex topic. One core finding of this Roadmap is that more work is needed on this topic. The urgency of climate change requires profound and rapid action. More data, input and technology options for decarbonizing industrial heat are urgently needed.

CHAPTER 1

INTRODUCTION

Roughly 10% of global greenhouse gas (GHG) emissions come from the production of heat for industrial processes. This is more than GHG emissions from cars and planes combined.[1,2] Decarbonizing industrial heat production will be essential to meeting the goals set forth in the Paris Agreement, including achieving net zero emissions in the second half of this century, yet technological approaches for decarbonizing industrial heat production are far from maturity. This topic has received far less attention than decarbonization of the power, transport and building sectors.

This Roadmap explores the challenge of industrial heat decarbonization. After providing background, we explore four technological approaches with the potential for generating industrial heat without GHG emissions: hydrogen; biomass; electrification; and carbon capture, use and storage. We next explore the potential for decarbonizing heat production in three industries: cement, iron and steel, and chemicals. We then turn to policy options and an innovation agenda. We close with findings and recommendations.

Background

Almost a quarter of global GHG emissions come from the industrial sector.[3,4] The cement, steel and chemical industries are the largest contributors. The refining, fertilizer and glass industries are significant contributors as well. In 2018, global industrial GHG emissions grew at a rate of 2.7%.[5]

Recent studies have provided excellent analyses of several strategies for reducing emissions, including process intensification, material substitution, overall demand reduction and energy efficiency.[6] Relatively little attention has focused on how industry uses heat.

In many industrial applications, high quality heat is the most important input after primary feedstocks. Heat production, usually through fossil fuel combustion, is either the largest contributor or the second largest contributor to industrial sector emissions. Together, industrial heat represents roughly 40% of total industrial emissions. Even with substantial efficiency gains, demand reduction and development of a circular economy, the ambitious goals of the Paris Agreement will be difficult or impossible to achieve without significant reductions in emissions from industrial heat production.

Requirements

Most heavy industries require enormous quantities of heat at high temperature. In many cases (including the cement, iron and steel, and chemical industries), the core industrial processes involve smelting ore, breaking strong chemical bonds or increasing a product's energy content. These processes produce substantial GHG emissions. Earlier this century, industrial emissions growth was driven by high temperature in sectors including cement and steel (in part to build Chinese megacities). Although these sectors still produce large emissions, current growth is from medium temperature applications including refining and chemicals.

The needs of the specific industries themselves vary considerably and are extremely heterogenous (even within one major production facility). Three requirements are key:

- **Temperature:** Industrial products are made through the application of high-grade heat to feedstocks. Temperature demands vary significantly from around 200 °C to nearly 2,000 °C **(Table 1.1)**.
- **Flux:** Industrial heat demands must be met with high (and commonly continuous) heat flux into the system. The flux must be large enough to sustain reasonable production **(Table 1.1)**.
- **Reliability:** Most heavy industrial production occurs at large facilities with high capital costs (e.g., refinery, steel mill). Most of these facilities operate with very high capacity factors, commonly 60-95%.[7] As such, heat supply must be dispatchable and available both throughout the day and throughout the year.

Any viable option to replace existing sources of industrial heat must be able to achieve the temperatures, fluxes and reliability necessary for robust, continuous operation. Approaches or fuels that cannot achieve high temperatures (e.g., heat pumps) or are intermittent (e.g., heating with variable renewable power) will have limited utility as viable substitutes. Finally, most options must operate in the specific geography where these industries exist and operate (e.g., along the Gulf of Mexico or Northern European ports).

Application & process	Temperature required (°C)	Energy requirements (GJ/ton product)
Glass: Silica melting	1,600	≈3
Cement: Clinker production	1,450	4
Steel: Blast furnace operation	1,100	11-14
Hydrogen production: Steam methane reforming	820	16
Fertilizer: Ammonia synthesis	450	36
Petrochem: Methanol synthesis	300	33

Table 1.1. *Temperature requirements and energy requirements per ton production for key industrial processes & applications (global averages)*

Options

Options for providing low-carbon heat of industrial quality are not well developed. Challenges can be physical or chemical (e.g., the temperature of steam at conventional nuclear power plants), geographic (e.g., the availability of solar radiance or biomass feedstock) and economic (e.g., the cost of electrolytic production of hydrogen).

Unfortunately, no option exists that can be widely deployed today. Current options include:

- **Hydrogen combustion:** Burning hydrogen made from electrolysis or decarbonized fossil fuels.
- **Biomass combustion:** Burning of unrefined biomass (e.g., agricultural wastes and wood pellets).
- **Biofuel combustion:** Burning of refined biomass (e.g., biogas, biodiesel and corn ethanol).
- **Electrical heating:** Direct and indirect heating approaches such as resistive heating, induction heating and dielectric heating (e.g., microwaves).
- **Carbon capture, use and storage:** Capturing CO_2 from combustion of fossil fuels (or biofuels) and sequestering it underground or in durable products.
- **Concentrated solar power:** Large facilities (e.g., power towers) and more distributed approaches (e.g., small parabolic mirrors).
- **Conventional and advanced nuclear heat:** Light water reactors, emerging small modular reactors and advanced nuclear processes (e.g., sodium-cooled fast reactors or nuclear fusion).

In considering these options, heat quality, cost, availability and carbon footprint are all important. Some of these options can serve only a limited number of industrial applications based on temperature requirements alone **(Figure 1.1)**.

Some low-carbon options will only prove viable for a small number of industrial applications. Stated differently, it is unlikely that one pathway will prove superior to the others in all contexts. A portfolio of fuels is likely to serve a range of potential industrial applications, and individual sectors or plants may select different options based on their geography, policy framework and asset requirements.

Nature of industrial operations and markets

Several characteristics of industrial operations and markets create challenges in decarbonizing industrial heat production.[8]

First, industrial facilities are long-lived capital stock. Turnover often takes place over many decades. Components such as rotary cement kilns, blast furnaces, catalytic crackers and hydrogen production units can individually cost $100s of millions and are central to the operation of multi-billion dollar assets. It may take 30-60 years to replace core components of a large industrial facility, and some facilities have operated for over 80 years and are still making products and revenues. This creates a high hurdle rate to rebuilding and replacing high-emitting units and affects the ability of innovative solutions to propagate into the sector.

Second, many industrial products are globally traded commodities (unlike electricity, which serves local or regional markets).[a] This means that prices of many industrial products are set by international trade. Small

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[a] Cement and concrete markets are exceptions, since they are mostly used locally (although that has begun to change).

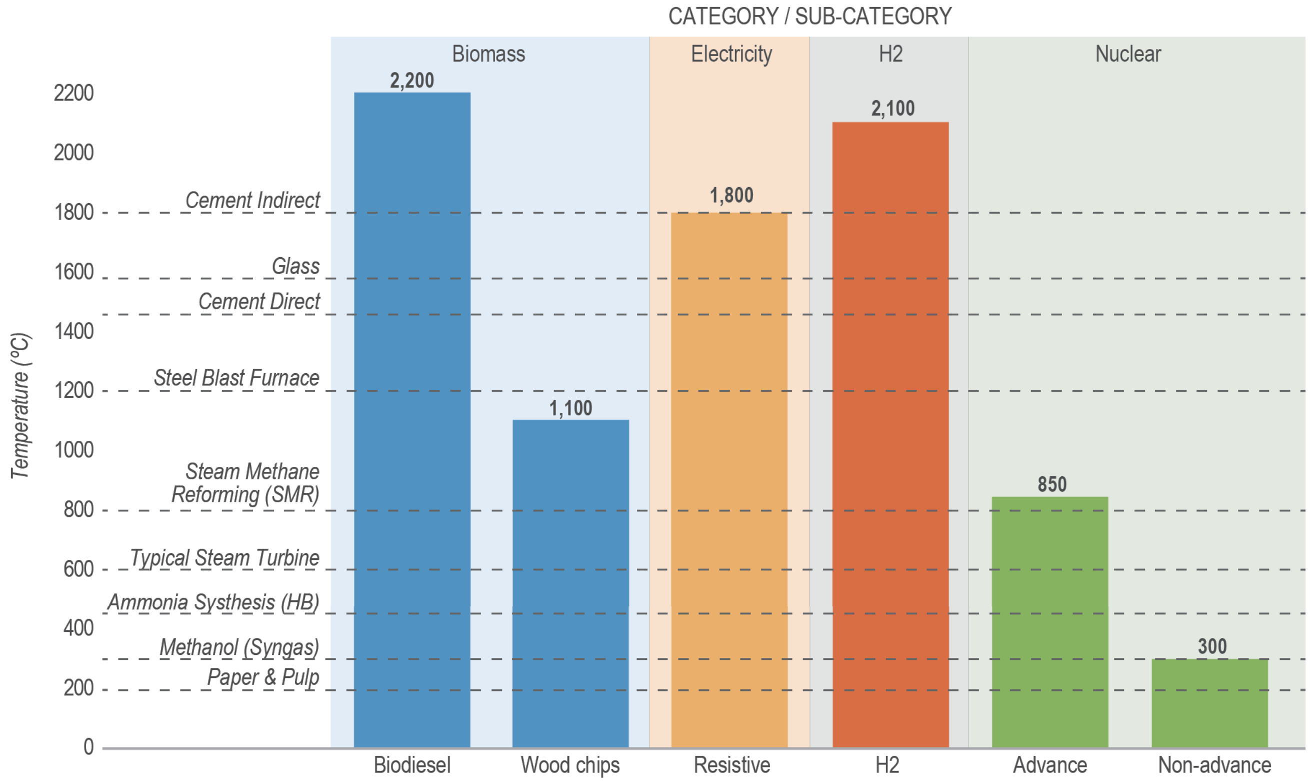

Figure 1.1. *Temperature requirements of key industrial process and the temperature limits provided by some options for low-carbon heat source replacements.*[8]

increases in production costs could lead to a dramatic loss of market share and loss of competitiveness overall, which can affect the national trade balance and the overall health of the industry. This has led to narrow margins[9,10] and a reluctance to increase costs.

Third, many industrial facilities are located far from renewable resources such biomass or solar radiation sufficient for concentrated solar power. Often, heavy industrial manufacturing facilities are found in ports to facilitate trade and delivery of feedstocks. For example, over 70% of the US refining capacity lies along the Gulf of Mexico coast in Texas and Louisiana.

Fourth, many governments consider these industries to be core national assets, affecting national security and the balance of trade. In part for that reason, these industries have sometimes received exemptions or waivers from carbon pricing and environmental regulations. In some cases, this has been a factor contributing to significant overcapacity (e.g., in Chinese and Korean steel production). While some of this overcapacity may lead to closures, it may also lead to life extension for lowest cost assets, which may have a poor carbon emissions profile.

Strategies for reducing GHG emissions from industrial heat production will be more likely to succeed if they take account of these qualities of the key sectors.

Framing for this Roadmap

More and better options for low-carbon industrial heat are essential to meeting global climate goals. To improve the existing options and develop additional pathways requires information and knowledge that is unavailable. The general lack of knowledge and information around the topic of industrial decarbonization (and industrial heat in particular) prevents investors, operators and policy makers from considering and implementing alternatives. This Roadmap explores options available today as an early foray into the subject.

This Roadmap is intended to be an initial, “1.0” analysis of options for decarbonizing industrial heat. In preparing this Roadmap, we have prioritized several technological pathways (hydrogen, biomass, electrification and CCUS). We do not explore other options including concentrated solar power, genetically modified organisms and nuclear heat. Our selection was based on factors including geographic availability, technological readiness and public acceptance. We explore several key industries (cement, iron and steel, and chemical) but have not had the chance to explore others (including pulp and paper, glass making, and aluminum smelting). We recognize that all viable options today are challenging, including most of those we have selected for analysis. The challenges include cost, availability, life-cycle carbon footprint and engineering viability.

Strategies for decarbonizing the industrial sector must also include efficiency improvements, material use reduction and development of a circular economy.[6] Decarbonizing production of industrial heat will be an important part of the solution set.

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CHAPTER 2

TECHNOLOGY OPTIONS FOR LOW-CARBON INDUSTRIAL HEAT

HYDROGEN

Hydrogen is the most abundant element in the universe and extremely abundant on Earth. When burned, hydrogen produces high-grade heat without carbon dioxide (CO_2) emissions. Substituting hydrogen for hydrocarbon fuels such as natural gas is one potential pathway for decarbonizing industrial heat production.

Although hydrogen is extremely abundant, it is usually bound to other elements in compounds such methane (CH_4) and water (H_2O). Separating hydrogen from these compounds requires substantial amounts of energy to break chemical bonds. The processes for doing so (chemical, electrical, thermal) are readily available today and used commercially in many industries in which hydrogen is a feedstock. Pipelines in many countries currently provide hydrogen as a feedstock to chemical and refining plants, steel plants and other industrial facilities.

Hydrogen can be burned in air, producing a 2100 °C flame. (If burned in oxygen, the heat of hydrogen combustion is 2800 °C.) Although today it is rare for hydrogen combustion to create an industrial heat source, some applications burn hydrogen in boilers, stoves and vehicle engines. Hydrogen combustion systems require special burners and in some cases require conversion from liquified hydrogen to gas form. In most other respects, hydrogen combustion for heat is extremely similar to burning natural gas and is a viable substitute for other gaseous fuels.

Roughly half of hydrogen produced today worldwide is from natural-gas reforming.[1] It is a mature technology and relatively energy efficient (65-75% conversion efficiency) and can operate wherever there is a natural gas supply. Gas reforming itself uses high-temperature heat (700-1,000 °C) at elevated pressures (15-25 bars), usually provided from natural gas furnaces. The reaction occurs in the presence of a catalyst. The fundamental chemistry of reformation can be represented in simple terms:

Steam-methane reforming reaction

$CH4 + H2O \text{ (+ heat)} \rightarrow CO + 3H2$

Water-gas shift reaction

$CO + H2O \rightarrow CO2 + H2 \text{ (+ small amount of heat)}$

Although the fundamental chemistry is straightforward, the engineering is more complicated. The key process (reforming) is strongly endothermic and consumes heat (i.e., 206 kJ/mol). It operates at high temperature which requires high combustion heat. Feedstock coming from a conventional natural gas pipeline must be purified, which requires separations of sulfur, nitrogen and other trace gases. These each have their own heaters, often provided by pre-heaters and often from heat recovery

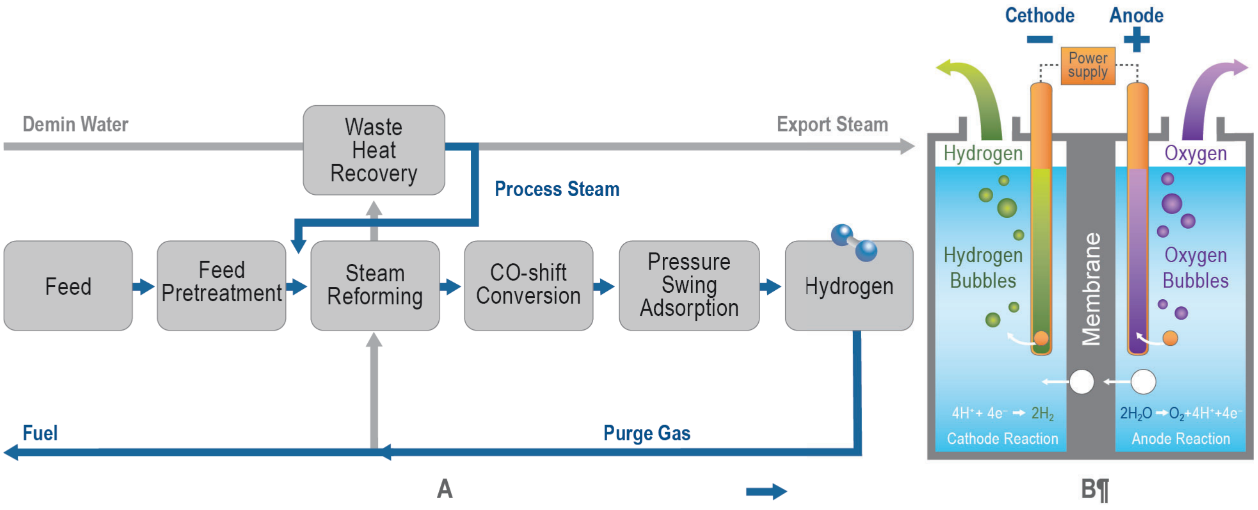

Figure 2A-1. *Hydrogen production processes. A: Steam methane reforming (SMR). B: Electrolysis of water.*

units. The final separations through the pressure swing adsorption unit also require heat and work.

In addition to steam-methane reforming (SMR), other approaches include autothermal reforming (ATR), partial oxidation and other more exotic methods (see below). In refineries, oil residues are commonly gasified and refinery gas streams are reformed. In locations where gas is expensive or supplies are limited (e.g., China, India, South Africa), coal or petcoke is gasified as an alternative feedstock to gas reforming and is commonly combined with a water-gas shift reaction to maximize production.[a] The dominant costs are the costs of gas (85% of total) and the heavy industrial equipment used in reformation. Importantly, CO_2 is a direct chemical byproduct of reformation and represents about 55% of CO_2 emissions from a facility (the rest comes from gas combustion in the heating systems).

Electrolysis of water is a completely different option for hydrogen production, using electricity as the energy source to break the chemical bonds in water, forming hydrogen and oxygen **(Figure 2A-1)**. The process requires an electrolytic cell and fairly pure water supplies. Electrolysis is typically more expensive than gas reforming, with costs principally determined by the costs of electricity and electrolyzers. The electricity for electrolysis can come from high-carbon or low-carbon sources. Electrolysis itself produces no greenhouse gases (GHGs).

Decarbonization has only recently become important to hydrogen production. Increasingly, scholars, environmental activists and policy makers have begun to classify hydrogen into three broad categories:

BOX 2-1 Other challenges with hydrogen

Hydrogen's potential to contribute to decarbonization has been extensively studied. This focus has revealed several physics and chemistry challenges to widespread hydrogen use.

- **Leakage:** Because hydrogen is a very small molecule, leakage risks are substantial, especially in pre-existing pipelines or devices. Special materials and gaskets are often required to ensure minimal leakage.
- **Safety:** Hydrogen is colorless, odorless and burns invisibly. On that basis, special monitors and sensors are needed to identify operating hydrogen combustion units and appropriate mitigation plans are needed to ensure safety.[6]
- **Corrosion and embrittlement:** In small fractions (7-20%), hydrogen can be mixed into existing pipeline networks with minimal consequence. At higher fractions, hydrogen can corrode conventional pipes, providing a leakage or safety concern. Moreover, hydrogen can make conventional metal pipes and fixtures brittle through aging and low-level reactions. Overt steps are needed to mitigate or counter corrosion and embrittlement, potentially including full pipeline replacement.
- **Storage:** Hydrogen is notoriously challenging to store. Many tank systems are adequate (either compressed, liquified or cryo-compressed) but require special materials and systems to avoid leak-off or other losses, sometimes adding substantial costs to hydrogen systems. Some work has begun on using engineered salt caverns to store hydrogen in large volumes.

While these issues are straightforward and manageable, they require attention to ensure safe and cost-effective hydrogen deployment in industrial settings.

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[a] Coal or petcoke feedstocks yield additional CO_2, roughly twice that of natural gas, requiring extra storage. In regions where CO_2 storage resources are limited, this can cause challenges to decarbonizing production.

- **Gray hydrogen:** H_2 production without carbon controls (typically SMR, venting byproduct and combustion related CO_2).
- **Blue hydrogen:** H_2 production with carbon controls (typically carbon capture, use and storage—CCUS).
- **Green hydrogen:** Electrolysis of water using only low-carbon electricity sources (e.g., renewables, nuclear).

All three categories of hydrogen production can have a wide range of GHG emissions. For example, both gray and blue hydrogen production carry the upstream emissions associated with methane production, which can vary substantially.[2,3]

For blue hydrogen, CO_2 capture can either be partial (i.e., from only the reformation unit) or applied to additional plant systems at additional costs (see below).[4] Today, four units around the world capture CO_2 from the reformation unit,[5] which represents an emissions reduction of roughly 53-60% per unit hydrogen. It is possible to reduce emissions from hydrogen production to much higher levels, commonly up to 90%, although even higher capture rates are possible. Blue hydrogen production is only viable at sites that can access CO_2 transport and storage infrastructure (i.e., where there are geological storage sites or pipelines that can move CO_2 to them).

For green hydrogen, the footprint of electricity production can vary greatly across regions. This underscores the need for careful life-cycle analysis to understand and estimate the carbon footprint of all forms of production. Many low-carbon electricity systems have low capacity factors, which can add substantial costs for firm power generation.

Estimated costs

Following Collidi et al.,[7] Friedmann et al.[8] developed a "levelized cost of hydrogen" (LCOH). LCOH estimates the unit cost of producing hydrogen over its economic lifetime, including capital costs, operating and maintenance costs, and capacity factors, as well as calculating different costs as a function of gas costs, power costs, conversion methodology and degrees of decarbonization.[9] These costs and assumptions are represented in **Table 2A-1**. and compared in **Figure 2A-2**.

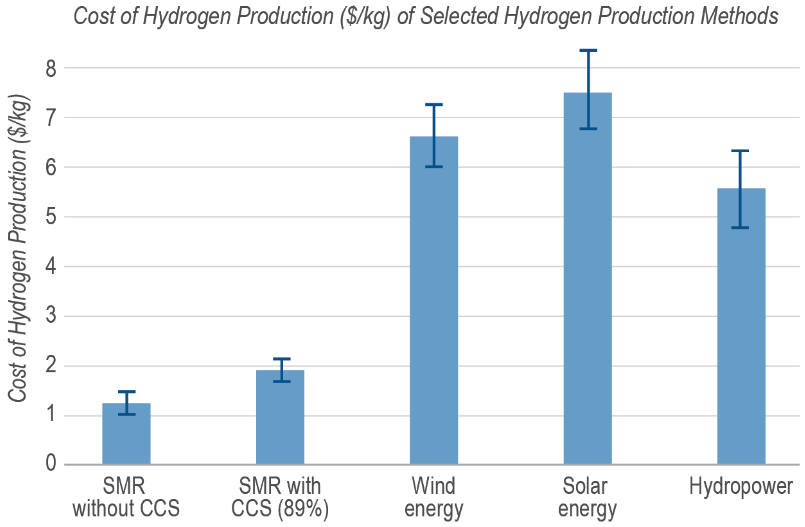

Figure 2A-2. *Cost of hydrogen production ($/kg) of selected hydrogen production methods (unsubsidized). Source: Friedmann et al. 2019*

Conventional production from natural gas without carbon capture and storage (CCS)(gray hydrogen) is cheaper than all low-carbon options. Partial or full CCS (blue hydrogen) increases costs by 20-50% depending on the degree of decarbonization. All electrolytic hydrogen is more expensive still, with US grid costs producing hydrogen at roughly twice the cost of gray hydrogen and resulting in only 20-30% carbon footprint reductions. When all power is generated with renewable sources, costs increase by a factor of 3-10.

A blue-green transition

Today, it is possible to generate low-carbon hydrogen at a large scale from natural gas and to decarbonize the production with relatively small increases in cost. It is likely that as CCUS technologies improve, the incremental cost of decarbonizing blue hydrogen production will drop somewhat as well. However, the principal element of blue hydrogen cost is the cost of natural gas itself, which is already low in North America, and it is hard to imagine dramatic cost improvements for blue hydrogen.

In contrast, the primary costs of green hydrogen (low-carbon electricity prices) have decreased dramatically and continue to drop. While it is unclear how much costs can or will decrease for solar or wind, it is plausible that capacity factors will increase for some renewable sources and that costs will drop with technology advances.[10] While curtailment today represents relatively small percentages of power generation, many scholars

H_2 PRODUCTION APPROACH			
Natural Gas Reformation*	**Capture Rate**	**LCOH**	**Cost of Heat (LHV)**
Steam-methane reforming without CCS	0%	\$1.05-1.5/kg[a]	\$8.78-12.51/GJ
Steam-methane reforming with CCS	53%	\$1.32-1.77/kg	\$11.02-14.75/GJ
	64%	\$1.46-1.91/kg	\$12.19-15.91/GJ
	89%	\$1.71-2.15/kg	\$14.22-17.92/GJ
Electrolysis of Water#	**Cost of Power**	**LCOH**	**Cost of Heat (lower heating value)**
US average grid + PEM (90% capacity factor)	\$60-90/MWh	\$4.50-6.04/kg	\$37.52-50.34/GJ
Solar PEV (20% capacity factor)	\$36-46/MWh	\$7.1-8.3/kg	\$59.2-69.2/GJ
Wind unsubsidized (35% capacity factor)	\$29-56/MWh	\$6.02-7.25/kg	\$50.17-60.46/GJ
Hydropower unsubsidized (40% capacity factor)	\$30-60/MWh	\$4.80-6.34/kg	\$40.01-52.83/GJ

* All natural gas capture cases assume 90% capacity factor, \$3.5/million BTU and \$20/ton costs for CO_2 compression, transportation and storage.

\# All electrolysis cases assume \$1,000,000/MW electrolyzer cost.

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[a] Even for fixed gas prices and capacity factors, the range of costs reflects choice of conversion technology (e.g., SMR vs. autothermal reformers).

Table 2A-1: *Estimated costs for hydrogen production (normalized to natural gas).*

have posited that overgeneration of renewables will prove cost effective. If so, costs for green hydrogen could drop substantially. They would drop further with substantial capital cost reductions for electrolyzers.

It is thus possible to imagine a transition from blue to green hydrogen supply. Low-carbon hydrogen systems could be deployed relatively quickly using blue hydrogen as a primary fuel, providing the ability to scale quickly and at modest additional cost. Over time, as green hydrogen became cost-competitive, it could gain market share for decarbonized heat and begin to displace blue hydrogen production. If so, future LCOH could remain fairly constant and possibly decrease while the total fraction of fossil-based hydrogen production decreases over time.

Potential to improve

To date, only four facilities in the world produce blue hydrogen. It is likely that as more carbon capture systems are deployed on existing facilities, engineers and innovators will find opportunities to decrease costs. Improvements could come from novel CO_2 capture systems that have lower costs themselves, from incremental learning-by-doing improvements in capital cost (e.g., reduction in steel, lower cost material substitution) or operating cost (e.g., improved heat recovery, more efficient systems). Similarly, for new hydrogen production facilities using conventional technology (e.g., SMRs, ATRs, gasifiers), costs and efficiencies could improve through integrated design.

Many groups have studied approaches to improve the cost and performance of electrolyzers.[9] These include discovery and functionalization of new materials, most notably metal anodes. Research to improve corrosion resistance and seal performance and to extend the capital life and longevity of components and integrated systems remains important. Ultimately, the largest cost element will remain the cost of electric power. Overall research to continue reducing the total cost for renewable power systems would help. In the near term, research should identify and map locations where a combination of features (e.g., high capacity

BOX 2-2 Alternative approaches to hydrogen production

Hydrogen can be generated through several other technological pathways. In some cases, these technologies are in early stages of development (low technical readiness level [TRL]). In other cases, the processes are well described and recognized but have not scaled due to high costs or other reasons.

- **Sulfur-iodine cycle:** This thermochemical cycle process generates hydrogen from water and recycles sulfur and iodine without their consumption. The cycle operates at high temperatures (~950 °C) from any source, although many consider it to be well-suited to heat from high-temperature nuclear reactors. The Japanese government and Savannah River National Laboratory have studied the process in depth, and a Japanese test reactor runs experiments to improve the efficiency and performance of the cycle. **TRL = 3**
- **Methane cracking:** Methane can be separated directly into carbon and hydrogen by breaking its chemical bonds. For example, the Kvaerner Carbon Black & Hydrogen Process (KCB&H) was developed by Norwegian company Kvaerner and uses a high-temperature plasma burner to directly separate methane into hydrogen and amorphous carbon (carbon black). The first plant was built and began operation in Norway in 1999 but has not received widespread adoption. This process does not emit substantial greenhouse gases, since all carbon is converted to solid form. **TRL = 5-6**
- **Biomass gasification:** Like natural gas, oil residues, coal or petcoke, biomass can be gasified and combined with water-gas shift to produce hydrogen. This has the advantage of a renewable feedstock (biomass) which could reduce the carbon footprint of production dramatically. This process today is expensive due to the high capital costs of gasifiers, challenges in feed systems and ash handling, and limitations of biomass supply. There are substantial ranges and uncertainties in carbon footprint. (See Biomass section, chapter 2B.) **TRL = 8**

Because low-carbon hydrogen will remain an important decarbonization option for industry and other applications (including heavy duty transport), research programs around the world should increase the size and scope of programs to develop new methods of hydrogen production.

factors, regular curtailment) produce extremely low-cost green power today in proximity to relevant industrial applications.

Finally, and perhaps most importantly, research is urgently needed on how best to implement hydrogen combustion systems in facilities that currently use other fuels. In some cases, the changes may prove fairly modest (e.g., new burner tips, sensors and controls). In other cases, substitution of low-carbon hydrogen may require new handling and fueling systems, as well as new designs for retrofitting complex systems and reactors. In some cases, additional NO_x control equipment may be required. For very challenging cases (e.g., cement kilns or blast furnaces) where solid fuel use is closely integrated with system operation, long-lived programs would help identify possibilities for substitution that could prove viable.

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BIOMASS

Biomass is the oldest source of industrial heat and provides about 10% of global primary energy.[1] Of this, roughly 15% goes to non-electricity industrial uses (7.8 EJ in 2009) with the rest used mainly for cooking, space heating, vehicle fuel and electricity generation.[2]

Expanded use of biomass has substantial potential to decarbonize industrial heat production. A wide variety of biomass types, from wastes such as manure and almond shells to dedicated energy crops such as sugarcane and switchgrass, can be used to provide industrial heat. Existing or emerging technologies are available to convert biomass to many intermediates, such as biomethane, biodiesel or bio-char. Unlike electricity or hydrogen, biomass can act as a carbon source and chemical reductant in steelmaking and other processes.

Climate impacts of bioenergy

Although combustion of biomass releases similar quantities of CO_2 as fossil fuels, biomass combustion can have substantially lower climate impacts because the CO_2 will be recaptured from the atmosphere when the source of the biomass regrows. For example, combustion of agricultural residues, like rice husks, is generally considered carbon-neutral because the crops will regrow the next season. This is also true for short-rotation woody biomass from sustainably managed forests. However, use of biomass can result in net land-use changes, reducing or eliminating any CO_2 emissions benefits. Transport, processing and use of fertilizer can also result in CO_2 emissions, reducing or eliminating the CO_2 benefits of bioenergy.

If supply of dedicated energy crops is substantially expanded, some land must be converted from other uses to grow the crops. There is typically a net change in carbon stored in the soil and flora when land use changes. If the previous use stored more carbon than the energy crop, then there will be an initial release of carbon to the atmosphere, followed by a reduction in carbon emissions to the atmosphere, compared to the scenario where fossil energy was used instead. Thus a “payback period” can be calculated based on the number of years it would take to compensate for initial carbon release. When converting degraded land or other types of cropland to energy crops, the payback period is generally a year or less. But clearing forest or native grassland to plant energy crops can result in payback periods of decades or centuries.[3]

Complicating the picture, many energy crops, including corn and sugarcane, can compete with food crops for land, which has ripple effects on the food system and can result in indirect land-use changes with carbon impacts. The lifecycle impacts, including the indirect land-use changes, have been studied extensively, primarily in the context of liquid biofuels for transportation. Some recent research has indicated that the CO_2-emissions impacts of indirect land-use changes may not be as strong as previously thought.[4] However, lifecycle impacts are still significant, especially for liquid fuels derived from energy crops. **Figure 2B-1** summarizes estimates of the lifecycle impacts from biofuels and fossil fuels. The greenhouse gas emissions impact of generating heat from biomass is generally low, with estimates ranging from negligible to 30 g CO_2eq/MJ.[3,5] For comparison, the impacts range roughly 80-150 g CO_2eq/MJ for fossil fuels, as shown in **Figure 2B-1**.

Current industrial use of bioenergy is dominated by solids (93% in the EU), followed by municipal wastes (3%) and biogas (2%).[6] To the extent that industrial use of bioenergy continues to favor solids and gases over liquids, which is reasonable given current demands and expected sources of biomass, the lifecycle impacts are somewhat less challenging for industry than for transportation. Still, most use cases of biomass for industrial heat are not truly carbon neutral. However, bioenergy could be made carbon neutral or carbon negative by addition of carbon capture and storage (CCS) to either the industrial process or the biofuel processing facility, as discussed below.

Biomass availability

Numerous assessments have been made of global biomass availability. Estimates vary widely, especially for dedicated energy crops, but there is moderately good agreement in the literature that 200-500 EJ/y of sustainably produced biomass can be available by 2050.[3,5] These values compare favorably with the estimated global industrial energy demand of 230 EJ in 2012, projected to rise to 330 EJ by 2040.[7] However, there are competing demands for biomass in a low-carbon future, including as vehicle fuel, dispatchable electricity and a means of negative emissions through bioenergy with CCS (BECCS). Most assessments of

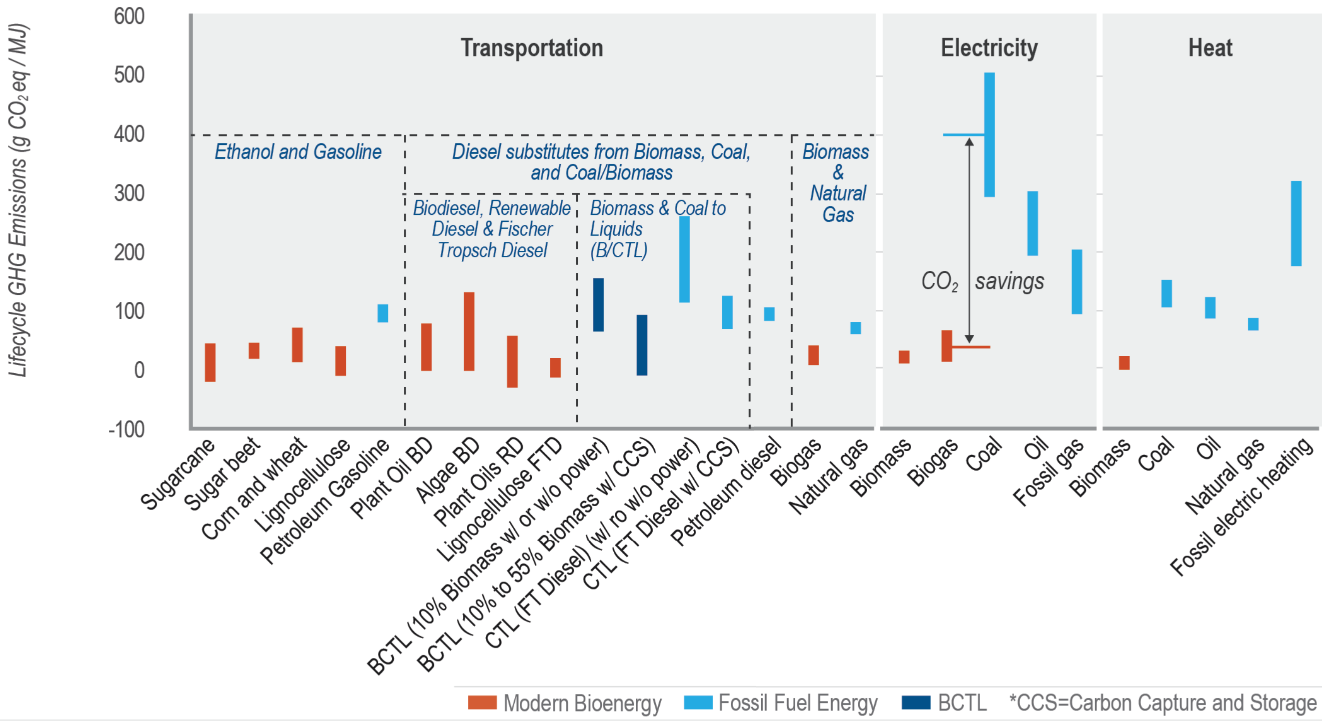

Figure 2B-1. *Summary of literature estimates of the lifecycle greenhouse gas impacts of bioenergy. Source: IPCC3 (used with permission).*

bioenergy as a climate-mitigation option have focused on liquid biofuels for transportation specifically. These competing uses will have to be balanced in a policy that encourages expanded use of biofuels in industry.

Also limiting its deployment in industry, biomass is more geographically diverse and more expensive to collect and transport than fossil fuels. For example, in Australia, bio-char suitable for steelmaking was found to cost about 4 times as much as coal, even though low-cost agricultural residues are also abundant there.[8] The production cost for solid biomass has been estimated to be in the range of 11-50 $/GJ using current technologies,[3] which makes it at least four times as expensive as coal and twice as expensive as natural gas in current markets.[9,10] This suggests that much of the potential biomass discussed above will be uneconomical to collect without strong incentives for industrial decarbonization.

Processing and transport

Since biomass grows over wide stretches of land, collection and transport is often a crucial component of the cost to use it. Woody biomass has about half the energy density and considerably lower bulk density (before grinding) than coal.[11] However, biomass can be converted to a variety of forms for easier transport and a wider range of uses. Common pathways are summarized in **Figure 2B-2**.

Most biomass sources, such as forest biomass and agricultural residue, contain up to about 50% water. Chipping and drying is the most common treatment for biomass currently used industrially, and this allows reasonable transport. There is already robust international trade in wood, which is the 5th most important traded commodity. Only about 10% of currently traded woodchip goes for bioenergy, but still pelletized wood for energy is traded internationally, primarily in Europe. With emerging technologies, these sources can be treated by a handful of other means to produce fuels for transport or further processing: gasification to produce biogas, syngas or hydrogen; pyrolysis to produce bio-oil and bio-char; torrefaction to produce torrefied biomass; and hydrothermal liquefaction to produce bio-oil.

As examples, top-level process diagrams for biomass gasification to hydrogen (**Figure 2B-3**) and biomass pyrolysis (**Figure 2B-4**) are shown below. With gasification, a range of biomass types can be converted into renewable hydrogen, which in turn can provide carbon-free heat. Depending on the biomass source, the CO_2 emissions resulting from the process may be

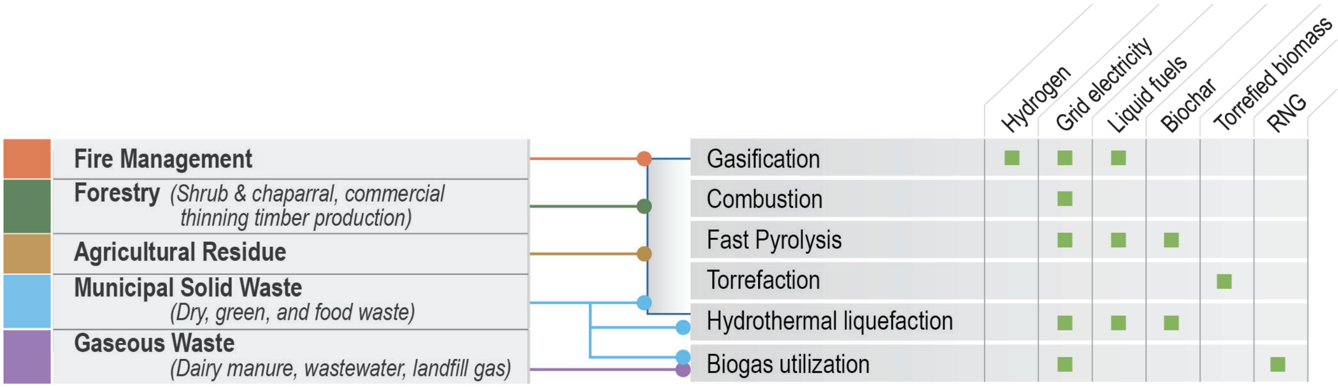

Figure 2B-2. *Biomass conversion pathways. (Fire Management refers to forest biomass, such as small-diameter trees and shrubs, removed from a forest to reduce fire risk or fire severity. RNG (renewable natural gas) refers to biogas that has been purified to meet natural gas pipeline standards (also known as biomethane).*

considered carbon neutral. However, this process is especially attractive because the relatively pure stream of CO_2 from the acid-gas-removal operation can be captured and sequestered, resulting in negative CO_2 emissions (analogous to BECCS), while also providing a stream of valuable hydrogen.

In the pyrolysis process, biomass is heated without oxygen to fractionate the material into gases, liquid fuels and bio-char. The bio-char and liquids can be used as industrial fuels. Typically, the gases are combusted to produce heat for the process, and the resulting CO_2 can optionally be captured to yield reduced or negative CO_2 emissions for the overall process.

Wet biomass streams, such as manure, wastewater, landfilled municipal solid waste (MSW) and food waste are most commonly treated with anaerobic digestion, creating biogas. In some cases, hydrothermal liquefaction can also be used. Biogas via anaerobic digestion is the least expensive source of bioenergy, with production costs estimated in the range of 1.5-8.7 \$/GJ, sometimes less than fossil gas.[3] However, the feedstocks for biogas are limited: manure, MSW, landfill gas and agricultural waste made up about 10% of total bioenergy use in 2007,[1] and these are unlikely to grow as much with demand as other types of biomass.

For most of the conversion pathways, additional refining can yield a fuel that is a drop-in replacement for a fossil fuel. Bio-char, depending on the process and biomass source, has a heating value of 30-38 MJ/kg, which is in the range of many coals.[11] Anaerobic digestion generates a biogas that is roughly half methane and half CO_2. If the CO_2 and minor impurities are removed, the remaining biomethane can meet specifications for natural gas pipelines. Syngas can be converted to desired fuels using conventional Fischer-Tropsch methods. Pyrolysis oil, although it starts with about half the heating value of crude oil because of its high oxygen content, can

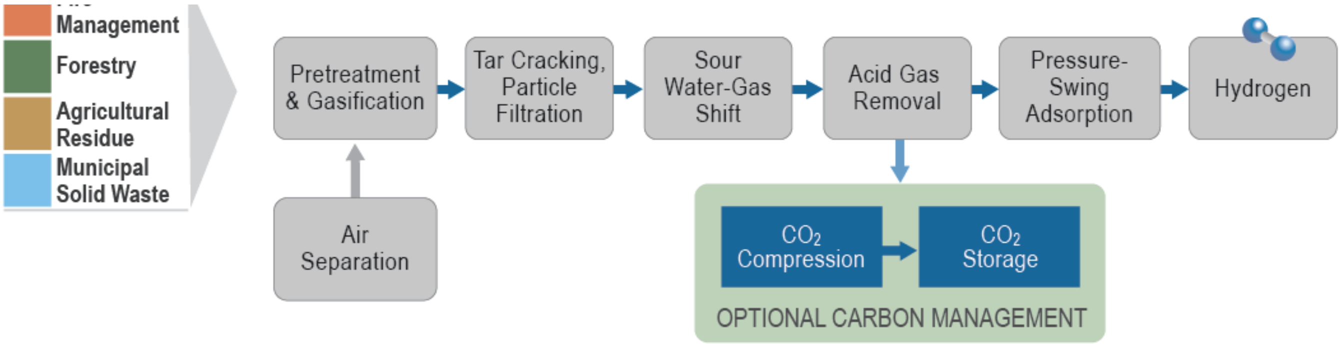

Figure 2B-3. *Process for biomass gasification to hydrogen.*

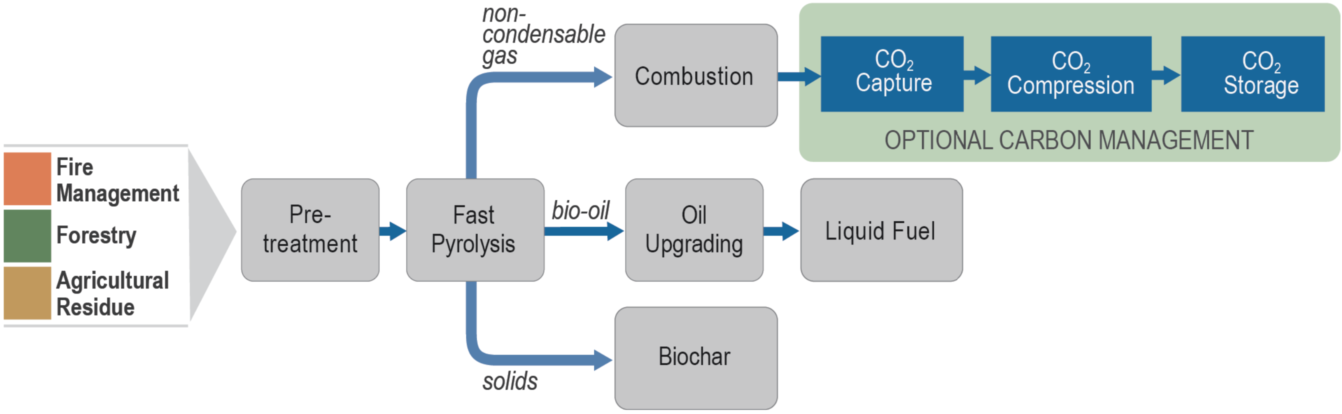

Figure 2B-4. *Process for biomass pyrolysis to liquid fuel and bio-char.*

be refined to standard vehicle fuels, depending on the desired product.

In most cases, refined biomass fuels are more expensive than competing fossil fuels, which has limited the market for conversion technologies in the same way as for biomass use. Except for anaerobic digestion, which is relatively mature, technology development and market incentives can still substantially improve the conversion processes and lower costs.

Specific applications

For certain industrial uses where the process is sensitive to fuel composition, further development is especially needed. As discussed in Chapter 3B, steelmaking is a complex process with both fuel and process emissions coming from multiple units of an integrated plant. Biomass can be substituted in several forms. Bio-coke can be produced to replace coal-based coke in the coking operation. Bio-char can be used in the sintering process and blast furnace. Bio-chars with higher heating values are more effective in the blast furnace. Pyrolyzed or torrified biomass may also be options to fuel the blast furnace.[12]

Multiple full-scale steelmaking plants already operate on biomass energy in Brazil, with 34% of the energy consumed by the iron and steel industry in that country coming from biomass.[6] Elsewhere, however, only low substitution rates of biomass have generally been achieved.[8] The composition and properties of bio-coke, in particular, need refinement and innovation—bio-coke does not yet perform as well as conventional coke due to higher reactivity and lower strength after reaction. In general, development of the biomass feedstocks to better function in existing steel mills and development of the basic oxygen furnace process to run better on biomass fuels are both important pathways to decarbonize steelmaking.

Regional biomass availability appears less of a concern for steelmaking. In an analysis of biomass availability compared with the locations of the current steelmaking industry, it was found that several of the top steel-producing countries have high suitability to adopt biofuels in steelmaking, including China, Russia, the US and Brazil. Japan, India and Germany had moderate suitability. Only South Korea, Ukraine and Taiwan had low suitability to biomass adoption, together accounting for 6.6% of global steel production.[8]

In contrast to steel mills, cement kilns are fairly tolerant to fuel variations and impurities because of their high combustion temperature. Although not typical practice, many cement plants across the world co-fire wastes and biomass along with fossil fuels when local conditions make this economically attractive.[13] Additionally, co-firing can have benefits for local air pollution by reducing emissions of sulfur and nitrogen oxides. Expanded use of biomass in cement operations appears straightforward, however it will not address the process CO_2 emissions from calcium carbonate decomposition.

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ELECTRIFICATION

Overview

A wide variety of electrical technologies are available to provide industrial process heat. When powered by low-carbon electricity, these technologies can provide process heat with very low greenhouse gas (GHG) emissions. Although the operational principles and capabilities of these technologies vary, they share several features because of their use of electricity.

First, electric heating systems can be precisely controlled by varying the electrical current, voltage or other parameters. This allows precision delivery of heat, minimizing energy waste and enabling automated process control. This feature stands in contrast to combustion-based process heat, for which the amount of heat delivered is more difficult to control. Similarly, electrical systems are able to provide heat flexibly at a range of design temperatures. Combustion systems, in contrast, are constrained by the combustion temperatures of their fuels.

A second, related feature of electrical heating systems is their ability to rapidly turn on and off. This allows them to have greater operational flexibility, ramping up and down heat delivery for a range of purposes. These can include adjusting processing operations based on grid or market conditions or enabling extremely rapid, brief heat application unit operations compared with combustion methods (for example, electron-beam curing).

Third, electrical heating systems tend to have relatively low maintenance. They are not exposed to combustion products or flame, and their components are almost entirely solid-state, with no fuel supply or storage requirement. These features tend to reduce or eliminate problems such as corrosion from combustion gases or flame impingement on refractory materials. Some electrical heating systems, such as inductive and microwave technologies, can apply heat without contacting the workpiece or material being treated, which reduces the potential for contamination and enables better control of the reaction environment during heat application.

The disadvantages of electrical heating systems include the need to provide large amounts of electric power, which may require additional infrastructure (such as distribution grid build-out and transformer installation) and place severe demands on the local electric grid (see below). In markets where natural gas is cheap and electricity is expensive, electrical heating systems will be at a cost disadvantage. Also, industrial processes that are optimized for combustion-based process heat are often highly optimized, taking advantage of waste heat for combined heat and power or recuperating it through heat exchangers or heat pumps. In these cases, replacing combustion heat with electrical heating may require substantial plant redesign. Unlike approaches to low-carbon heat treatment that are essentially low-carbon fuel replacements, such as hydrogen and biofuels, electrical heating cannot leverage existing combustion-based industrial process designs and generally cannot be retrofitted into an existing process without significant equipment modification.

Principles of electrical heating

At the most basic level, heat can be transferred to a process material in three ways. Convective heating is the transfer of heat energy through the motion of a fluid, such as water or air; it is generally constrained by parameters such as fluid flow rate and heat capacity. Conductive heating results from direct contact between the process material and a solid heat source; it is impacted by the thermal conductivity of the process material. Radiative heating is caused by electromagnetic (EM) waves (such as microwaves) arriving at the process material; it is constrained by both the reflectivity and absorption of the process material to the wavelengths used.

In an engineering context, there are two broad approaches to applying heat energy. Direct heating applies an electric current through the process material to cause resistive heating, induces an electric current in the process material using alternating magnetic fields, or excites molecules within the process material with electromagnetic radiation (microwaves or radio frequency). In each of these cases the material must have suitable properties (such as electrical conductivity). Indirect heating is used in cases where the process material is not suitable for direct heating and instead uses one of these methods to heat a separate susceptor or element that is near or in contact with the process material, which then transfers that heat to the process material through conduction, convection or radiation.

Figure 2C-1. *An infrared dryer for automobile paint. Short-wave infrared emitters can reach filament temperatures of 2,000°C. (Dmitry Kalinovsky/Shutterstock.com)*

Specific electrical heating methods

Direct resistance heating is the simplest of all electrical heating methods, particularly for conductive material that can be directly heated by the application of electric current. The material can be clamped to electrodes in the wall of the furnace in order to apply current. Joule heating resulting from the interaction of the current and the electrical resistance of the process material can be highly efficient, particularly for materials with high resistance (e.g., steel). Temperatures up to 2,000 °C are possible.[1,2]

Indirect resistance heating uses electrical resistance in a heating element, which is commonly made from graphite, silicon carbide or nichrome (nickel-chromium alloy). The heat is transferred by conduction, convection or radiation (similar to infrared heating, below) to the work material. Various geometries are used; tubular heating elements are common and comprise a nichrome heating coil surrounded by magnesium oxide for electrical insulation, sheathed in stainless steel. These systems have a maximum temperature of approximately 750 °C and can deliver heat at powers ranging up to 120 Watts per square inch of surface area. Indirect resistance heating is used in electric indirect rotary kiln technology, in which resistive heaters are placed outside of a rotating high-temperature alloy shell and heat is transferred to process material inside; these systems can reach temperatures of 1,200 °C.[1,2]

Infrared heating is based on passing an electric current through a solid resistor to heat it and then directing the resulting infrared radiation to the process material. The material must have relatively high absorption and low reflectance for infrared wavelengths corresponding to the temperature of the radiator. Short-wave emitters reach the highest temperatures, up to approximately 2,000 °C, using evacuated quartz tubes with tungsten filaments, back-filled with argon to prevent oxidation. Medium- and long-wave emitters use the tubular heating elements described above or wires embedded in ceramic panels. Baffles and reflectors can focus infrared radiation on the process material, improving efficiency. The heat transfer is mostly confined to the surface of the process material and is therefore most appropriate for surface applications like curing and drying.[1,2]

Microwave heating is based on the fact that microwave radiation (with frequencies in the range of 300 to 300,000 MHz) heats non-conductive (dielectric) materials that are composed of or contain polar molecules, such as water. Microwaves excite these molecules into motion, which leads to friction heating. The heat energy can be deposited throughout the bulk of the process material as long as it is not too thick. However, because microwave radiation is coherent with a wavelength in the range of a millimeter to a meter, standing waves can develop in heating chambers, leading to local hot and cold spots. Microwaves are generated in a magnetron and generally must be guided or contained to ensure efficiency and minimize exposure. Radio frequency heating works on a very similar principle, although it uses lower frequencies (2 to 100 MHz) with correspondingly longer wavelengths. These are able to penetrate farther into process materials, although they tend to deliver heat more slowly.[2,3]

Induction heating is based on an alternating magnetic field, generated by passing an AC electric current through a coil (solenoid). This field in turn induces alternating eddy currents in the work material if it is electrically conducting. For optimal efficiency, the work material is placed within the solenoid, or the magnetic flux is coupled into the material in other ways. Induction heating avoids any physical contact between the heating system and the process material. However, the energy is mostly deposited on the surface of the material (due to the skin effect). If the work material is not conducting, it can be put in contact with a susceptor, which is heated inductively and transfers heat through conduction or convection. Common applications are refining and re-melting of metals, including aluminum, copper, brass, bronze, iron, steel and zinc.[1,2]

Electric arc furnaces consist of a refractory vessel with retractable electrodes, often made from graphite or carbon. AC or DC current is passed through the electrodes and forms an electric arc with the process material. This deposits heat both from the direct resistance of current passing through the material and from the radiant energy from the arc. Commercialized arc furnaces range from a few tons to hundreds of tons of capacity. The electrodes wear out and must be replaced; suitable electrode materials are important for the overall economic viability of the technology. An alternate but less common configuration is the indirect arc furnace, which draws the arc between electrodes, applying heat through radiant transfer. Electric arc furnaces are commonly used in steelmaking, where they achieve temperatures up to 1,800 °C, as well as in the production of ferronickel in the Rotary Kiln–Electric Furnace (RKEF) process.[2,4,5]

Electron beam heating uses a focused beam of electrons directed onto a process material, usually in vacuum. Common uses include cross-linking polymers, welding, surface hardening for high-wear automotive components, and additive manufacturing. Electron beam furnaces are used in melting refractory metals such as titanium. The heating is primarily at the surface of the material, making bulk treatment more challenging.[6,7]

Plasma heaters operate by developing an electric arc across two cooled electrodes; gas (of many different compositions, including a variety of waste gases) is directed past the arc, which ionizes it into plasma that can reach temperatures from 2,000–20,000 °C. The

Figure 2C-2. *Electric arc furnaces use electric current to form an arc between electrodes, providing high-temperature heat to melt scrap steel and iron. (D.Alimkin/Shutterstock.com)* plasma forms a jet, which is then directed onto the work material, heating it. Plasma processing is commonly used in the titanium industry, as well as in the disposal of toxic ash, asbestos and sludge.[8,9]

For low-temperature process heating requirements (generally under 200 °C) there are several electrical technologies available that make use of waste heat, including heat pumps and organic Rankine cycle turbines. Solar process heating is also available for temperatures up to 250 °C.[10] However, these are not effective for medium- or high-temperature process heat.

Installation considerations

Combustion-based heating for a range of industrial processes usually involves furnaces whose design has been optimized for delivering heat from one or more individual point locations (burners) where fuel is combusted. The furnace is designed to handle the flow of combustion and reaction gases and may also include heat integration to recapture waste heat for other uses in the overall process. While some modifications are required for this design to burn alternative fuels such as hydrogen and biomass, the basic architecture largely remains the same. However, modifying the design to use electric sources of heat requires much more substantial changes.

- First, electric heat is generally not delivered from point sources (burners). Direct heating methods deposit heat energy throughout a material or potentially in a surface layer. Indirect heating generally delivers heat across the surface of a material. This can significantly change the distribution of temperatures within a furnace and thus the heating rates of the work material, potentially requiring process redesigns.
- Second, there is no need to handle combustion gases, as none are generated in the heating process. However, heat-integration systems will no longer be able to use this waste heat, potentially leading to a cascade of necessary process changes throughout the overall facility.
- Third, replacing fuel combustion with electrification removes the need to handle fuel delivery to burners, but it may create the need for managing high-voltage electric power distribution through active cooling, electrical isolation, etc. In general, the architecture and design assumptions of electric process heat are very different from those for fuel-combustion-based process heat and lead to a far larger need for process redesigns. As a consequence, the capital costs for process changes to electrification are generally higher than those for switching to alternative fuels.

System consideration

Electrification of process heat can create significant difficulties for local electric-grid operation. Large power consumers that function in a batch mode are particularly challenging, since they can rapidly increase or decrease overall power demand and require generation to ramp quickly. In some cases, such as electric arc furnaces for steel production, there may be strategies to harmonize operations with demand-side management (DSM) systems put in place by grid operators, but this can lead to highly complicated timing decisions.[11,12] In other cases, such as electrolytic production of hydrogen, it may be possible to add flexibility to a continuous process to participate in DSM or provide other grid services.[13] Ultimately, wide-scale electrification of process heat would require more integrated system planning between industrial customers and grid operators to better understand the opportunities and challenges.

Conclusions

- A wide variety of electrical technologies are available for delivering process heat. These can achieve temperatures of well over 1,000 °C and, in some cases, over 10,000 °C.
- Electrified process heating has several advantages over combustion-based heating, including precision temperature control, high flexibility and low maintenance costs. However, it requires large amounts of electric power, which may be unavailable or cost prohibitive.
- Electric heating systems can be categorized as direct, in which a working material is heated directly through electric resistance, microwaves or other techniques, or as indirect, in which a separate device such as a susceptor or resistor is used to deliver heat through conduction, convection or radiation.
- Installation of electric heating systems in facilities currently using combustion-based heating may require substantial process changes and corresponding capital investment. It may also eliminate heat integration methods that had been in use to recuperate waste heat, creating requirements for installation of additional heating systems.
- Electrification of process heat may also place

significant strain on the local electric grid, requiring capital-intensive upgrades to electric transmission and distribution facilities. In some cases these systems can participate in demand-reduction programs to ease the impact on the grid, but in others this may not be possible due to the need for continuous or inflexible process heat delivery.

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CARBON CAPTURE, USE AND STORAGE

Carbon capture, use and storage (CCUS) is a collection of technologies that result in substantial reductions of CO_2 emissions.[1,2] The building blocks of CCUS include:

- separation of CO_2 from combustion products (such as flue gas) or hydrocarbon fuels;
- transportation of CO_2 to a suitable geologic storage site;
- injection of CO_2 into a reservoir where it becomes trapped deep underground; and/or
- use of CO_2 in enhanced oil recovery, alkaline minerals (e.g., steel slag), aggregates, chemicals, fuels or other products.[3]

CCUS does not, strictly speaking, decarbonize production of industrial heat—after all, CCUS is based on the capture of CO_2 that results from use of carbon-containing fuels. However, CCUS is an attractive option to reduce emissions from industrial heat because CCUS does not, in principle, require a wholesale change in the design of industrial facilities or underlying production processes. However, as the case studies on cement, iron and steel, and chemicals in this Roadmap illustrate, CCUS provides maximum benefit when closely integrated with underlying industrial processes. There are generally three routes to CO_2 capture, all of which have relevance in industrial applications: pre-combustion, post-combustion and oxy-combustion.

In pre-combustion CO_2 capture, a hydrocarbon fuel is converted to a mixture composed predominantly of CO_2, hydrogen (H_2) and water from which the CO_2 is separated, leaving hydrogen for use as a fuel (**Figure 2D-1**). The hydrocarbon fuel can be natural gas or a solid fuel—e.g., coal, biomass—that has been gasified. The advantage of pre-combustion capture is that the total pressure of the CO_2 and H_2 mixture is relatively high, as is the concentration of CO_2 therein, making the separation process less energetically intensive and more compact. Solvent-based separations dominate, but membrane and adsorption processes (e.g., pressure swing adsorption) are also increasingly popular in commercial applications. In principle, this is the route used for CO_2 capture from steam-methane reforming (SMR) in production of blue hydrogen—although, it may also be combined with post-combustion capture to maximize CO_2 removals from SMR.[4] Pre-combustion capture for CCUS is used commercially today in fertilizer production,[5] refining[6] and SMR.[7,8]

Post-combustion capture is separation of CO_2 from the products of combustion—referred to commonly as flue gas (**Figure 2D-2**). Flue gas is composed primarily of nitrogen, CO_2, water and lesser amounts of pollutants (e.g., oxides of sulfur and nitrogen), where the nitrogen comes from the atmosphere. Flue gas is typically at close to atmospheric pressure, with a relatively low CO_2 concentration (i.e., typically less than 10% by volume), making the separation typically more energy intensive than for pre-combustion capture. The clear benefit of post-combustion capture, however, is that it can be added as an "end-of-pipe" solution for almost any stationary combustion process using any fuel. Solvent-based absorption processes dominate in commercial applications, but advanced solvents, adsorbents and other processes (e.g., calcium looping) are being developed.[2,9] Post-combustion capture for CCS has been commercially applied in power generation in two cases.[5]

The third route to CO_2 capture is referred to as oxy-combustion (**Figure 2D-3**). In its most straightforward implementation, a hydrocarbon fuel is burnt in oxygen—typically diluted with recycled CO_2 for temperature

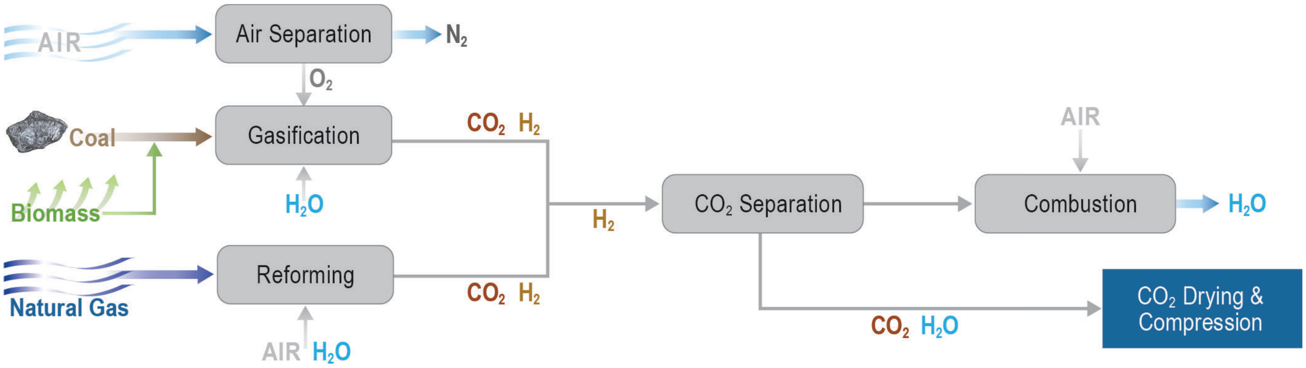

Figure 2D-1. *Typical pre-combustion capture process for solid fuels (coal, biomass) and natural gas. The water-gas shift reaction is not illustrated here for the sake of simplicity.*

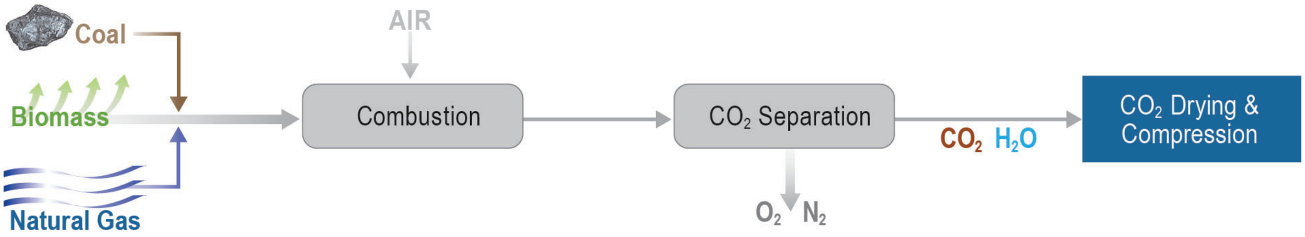

Figure 2D-2. *Typical post-combustion capture process for coal, biomass and natural gas. Cleaning of the flue gas is not illustrated here for the sake of simplicity.*

control. The resulting combustion products are CO_2 and water, the latter of which can be easily removed, leaving CO_2.[10] Chemical looping processes can also be considered an oxy-fuel route, but chemical looping combustion may be less relevant to industrial processes than the closely related chemical looping reforming, which could be an alternative means to produce hydrogen while capturing CO_2.[11] Similarly, power-generation cycles based on oxy-combustion of natural gas are in development,[10] but these typically are less relevant for industrial-process heat applications. The notable difference between the oxy-combustion routes and others is that oxy-combustion does not require CO_2 separation and instead involves separation of oxygen from air. Oxy-fuel CO_2 capture has been demonstrated at industrially relevant scales but has not yet been commercially applied.

Once CO_2 has been captured from an industrial process via one (or more) of these three routes, the CO_2 must be transported to a location suitable for geologic storage and then injected into the storage reservoir. Perhaps the most well-practiced component of the CCUS chain is CO_2 transport. In the US, over 7,000 km of pipeline transport around 70 MtCO₂/y of CO_2, predominantly for use in enhanced oil recovery (EOR).[12] The US pipeline network extends into Canada as well, delivering CO_2 for use in EOR, and is being extended in Alberta to enable large-scale CCS. National and international standards exist for design and construction of such pipelines[a], as do government safety regulations where such pipelines exist[b]. Shipping of CO_2 is also currently practiced at small scales and is being considered as part of a Norwegian integrated CCS demonstration project[c]. Transport by rail or truck may also be an economically viable option for small-scale sources (e.g., less that 100 ktCO$_2$/y) over relatively short distances.[13]

Experience with CO_2 storage in geological formations has been growing, as EOR projects that inject and store CO_2 have been undertaken since the 1960s and the first dedicated geological storage project began operations in 1996. In addition, governments have continued to support research to advance tools and methods for measuring and predicting the behavior of stored CO_2. This growing knowledge base has been reflected in development of standards for geological storage in recent years.[14,15]

A suitable geologic storage site must have sufficient capacity to hold the desired quantity of CO_2, while also being able receive the CO_2 at acceptable rates

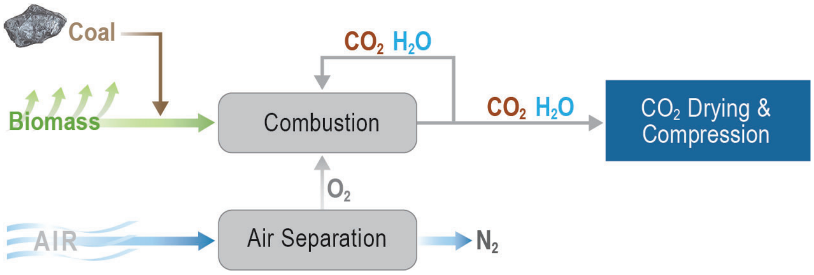

Figure 2D-3. *Typical oxy-combustion process for solid fuels (e.g., coal, biomass). Natural gas could also be used in such a process.*

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[a] E.g., in Canada, CSA Z662; Europe, DNV-RP-J202; and, internationally, ISO 27913:2016.

[b] E.g., in the United States, 49 CFR Part 195.

[c] See https://ccsnorway.com/

through a reasonable number of wells. It must also safely contain this CO_2 permanently—or at least for the foreseeable future.[16]mainly coal, for power generation and combustion in industrial processes because they are relatively abundant, cheap, available and globally distributed, thus enhancing the security and stability of energy systems. Geological media suitable for CO_2 storage through various physical and chemical trapping mechanisms must have the necessary capacity and injectivity, and must confine the CO_2 and impede its lateral migration and/or vertical leakage to other strata, shallow potable groundwater, soils and/or atmosphere. Such geological media are mainly oil and gas reservoirs and deep saline aquifers that are found in sedimentary basins. Storage of gases, including CO_2, in these media has been demonstrated on a commercial scale by enhanced oil recovery operations, natural gas storage and acid gas disposal. Some of the risks associated with CO_2 capture and geological storage are similar to, and comparable with, any other industrial activity for which extensive safety and regulatory frameworks are in place. Specific risks associated with CO_2 storage relate to the operational (injection The practical global capacity to store CO_2 in saline formations is believed, on the basis of geological assessments for select regions of the world, to be upwards of 4,000 $GtCO_2$. Another 1,000 $GtCO_2$ are estimated to be available in depleted oil and gas reservoirs.[17] While these capacity numbers are large, they hide the uneven geological distribution of storage resources and the challenge of characterizing, assessing and developing storage sites, which can be high risk and take many years to a decade. This timeline can also be complicated by the laws and regulations that may—or may not—exist to facilitate safe, effective CO_2 storage.[18]2005 Many governments have recognized that coordinating and supporting development of CO_2 storage sites is as important to future deployment, if not more so, than support for technology development.[5] Consequently, there is growing emphasis on development of storage-centric and integrated CCUS projects that are focused around clusters of emitters (e.g., the Port of Rotterdam, Northern Alberta) and linked to transport and storage hubs (e.g., in the North Sea, EOR in Southern Alberta).[5,19] Many of these hub and cluster projects involve the cement, iron and steel, and chemical industries.

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CHAPTER 3

CASE STUDIES

CEMENT

Industry Overview

Cement is the foundation for the built environment. When combined with aggregates and water, cement makes the concrete used in roads, runways, buildings, bridges, dams and other structures on which societies around the world depend.

In recent years, over 4 Gt of cement have been produced annually.[1,2] Global demand for cement has been growing rapidly, expanding by nearly a factor of four between 1990 and 2014, when it reached around 600 kg/capita.[1] The vast majority of growth in production since 1990 has occurred in China, making China's per capita production today triple the global average. Global demand for cement is expected to continue growing, with some rebalancing of supply and demand at the regional level (including reduced production in China and increased production in India and other Asia-Pacific countries).[3]

In 2014, production of cement contributed over 2 $GtCO_2$ to global greenhouse gas (GHG) emissions (about 6% of the global total).[4,5] Of this amount, around 40% was emitted from the use of fossil fuels to provide process heat in clinker production, while the remaining 60% was emitted directly from the chemical decomposition of limestone (see **Box 3-1**). These figures do not include indirect emissions from generation of electricity used in cement manufacturing (e.g., crushing and conveying of materials) or mining of limestone and other minerals.

Decarbonization pathways

Many strategies for decarbonizing cement production have been proposed. Some have been implemented. There are many technical options for reducing the CO_2 footprint of cement production directly,[3,6,7,8] as well as a growing literature that considers the problem more holistically.[1,9] Approaches proposed to date include:

- Switching to less carbon-intensive fuels, such as sustainable biomass and wastes that would otherwise be incinerated or improperly landfilled—a practice that is becoming more common today.[3,7,10]
- Improving the efficiency of existing cement plants through retrofits that reduce both thermal energy demand in clinker production and overall electricity demand.[3,7,10]

BOX 3-1 Cement and Concrete

Concrete that is used in the construction industry is a mixture of cement (sometimes referred to as binder), water and solid aggregates such as sand, gravel and crushed stone (sometimes referred to as filler). A typical mixture by volume is 10-15% cement, 15-20% water and 60-75% aggregate. Manufacturing traditional Portland cement involves heating limestone (calcium carbonate) and other minerals (primarily aluminosilicates) in a kiln to form a material known as clinker, which is mixed with other constituents (e.g., gypsum, fly ash, steel slag) and ground into a fine powder. When this is mixed with water and aggregates, a series of chemical processes ("curing") converts the cement powder into interlocking crystals, which grow stronger over time. These crystals give concrete very good compression strength—so it can support a lot of weight—but poor tension strength, meaning that it cannot resist being pulled apart unless other materials are added, such as steel ("rebar"). The length of time it takes concrete to reach its required strength is referred to as "design age" and is impacted by the amount and formulation of the cement, as well as curing conditions. The hydrated calcium oxide found in cement is very reactive with CO_2 and, in fact, the cement naturally absorbs CO_2 out of the atmosphere over its life—although this is only a small fraction of that released during clinker production.

- Waste heat recovery for electricity production that reduces demand for higher carbon intensity offsite power generation.[3,10]
- Application of carbon capture and storage (CCS) to reduce the emissions from both fuel combustion and decomposition of limestone (calcination) to lime during clinker production.[3,7,10–13]
- Reducing the clinker content of cement through the addition of supplementary carbonaceous materials (SCMs)—e.g., fly ash, steelmaking slag, limestone and calcined clay—and optimizing the choice of SCMs for the application.[1,3,7,10,14,15]
- Optimizing design of concrete structures and choice of concrete formulations to use concrete more efficiently,[1] and increasing the design age of concrete structures—i.e., allowing a longer time for the cement to reach the design strength—in order to reduce the amount of cement required.[14]
- Development and application of alternative binders for cement,[1,10] such as beliteye'elimite-ferrite (BYF) clinkers,[16] carbonate calcium silicate clinkers (CCSC),[16] or alkali-activated materials (AAM).[17]
- Industrialization of cement production in emerging economies to increase efficiency of production processes, improve quality control and reduce overall waste generation.[1,9]
- Better managing concrete waste from demolition in order to accelerate natural uptake of CO_2 through carbonation of the active phases in cement, which could theoretically result in full uptake of the original emission from calcination, albeit in the distant future.[18,19]

Some options in this menu (e.g., use of biomass fuels, efficiency improvements and waste heat recovery) are relatively straightforward, with little impact on the cement making process or resulting product. Other options (e.g., CCS) would require more substantial and capital-intensive modifications. Some options would require changes in the way cement is used (e.g., optimization of design, increased design age) or even replacement of conventional cements to some extent (e.g., alternative binders). Of these options, the only two that would directly result in reductions in process heat emissions from ordinary Portland cement (OPC) manufacturing are substitution of sustainable biomass for fossil fuels and CCS. Little has been written about the use of hydrogen and electricity for provision of the heat needed in cement making. This case study reviews the way heat is provided in manufacturing of OPC and then examines the potential benefits and costs of fuel substitution, CCS, hydrogen and electricity.

The cement manufacturing process

OPC is composed of calcium carbonate, clay and lesser amounts of other minerals (e.g., sand, bauxite and alumina). These materials are crushed, mixed together in specific proportions and ground into a raw meal that is heated to produce Portland cement clinker. The clinker is then mixed with relatively small amounts of gypsum (calcium sulphate)—added to slow setting of the cement—and ground into the fine powder that is OPC. It is in these later steps that SCMs and fillers (e.g., limestone) can be added to create specialized cements. This process is illustrated inOPC is composed of calcium carbonate, clay and lesser amounts of other minerals (e.g., sand, bauxite and alumina). These materials are crushed, mixed together in specific proportions and ground into a raw meal that is heated to produce Portland cement clinker. The clinker is then mixed with relatively small amounts of gypsum (calcium sulphate)—added to slow setting of the cement—and ground into the fine powder that is OPC. It is in these later steps that SCMs and fillers (e.g., limestone) can be added to create specialized cements. This process is illustrated inOPC is composed of calcium carbonate, clay and lesser amounts of other minerals (e.g., sand, bauxite and alumina). These materials are crushed, mixed together in specific proportions and ground into a raw meal that is heated to produce Portland cement clinker. The clinker is then mixed with relatively small amounts of gypsum (calcium sulphate)—added to slow setting of the cement—and ground into the fine powder that is OPC. It is in these later steps that SCMs and fillers (e.g., limestone) can be added to create specialized cements. This process is illustrated in Figure 3A-1, which represents today's state-of-the-art cement-making process., which represents today's state-of-the-art cement-making process., which represents today's state-of-the-art cement-making process.

In the state-of-the-art "dry-kiln" process (OPC is composed of calcium carbonate, clay and lesser amounts of other minerals (e.g., sand, bauxite and alumina). These materials are crushed, mixed together in specific proportions and ground into a raw meal that is heated to produce Portland cement clinker. The clinker is then

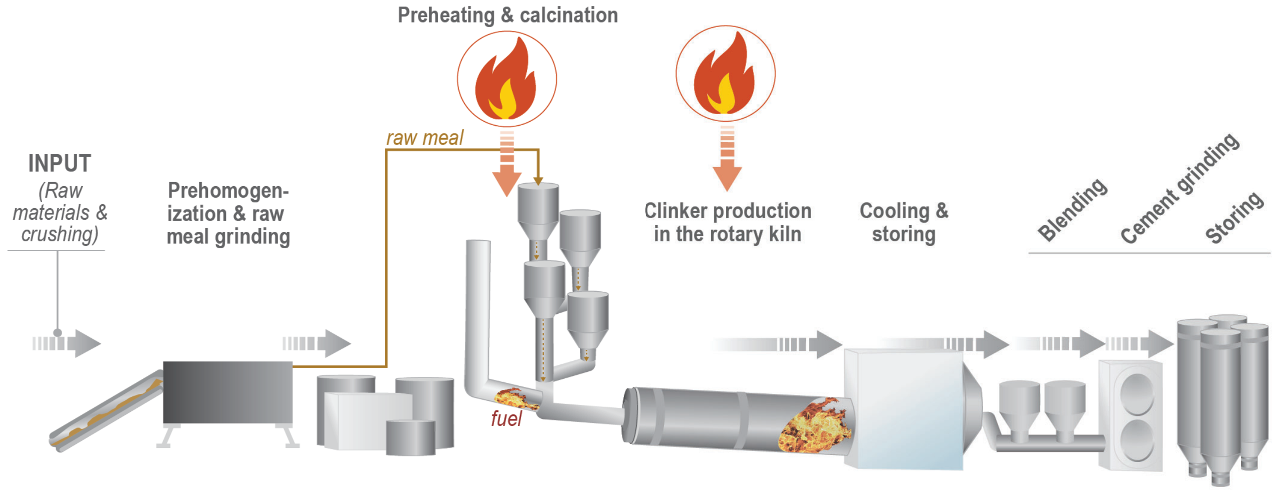

Figure 3A-1. *Current state-of-the-art dry-kiln Portland cement manufacturing process.*

mixed with relatively small amounts of gypsum (calcium sulphate)—added to slow setting of the cement—and ground into the fine powder that is OPC. It is in these later steps that SCMs and fillers (e.g., limestone) can be added to create specialized cements. This process is illustrated inOPC is composed of calcium carbonate, clay and lesser amounts of other minerals (e.g., sand, bauxite and alumina). These materials are crushed, mixed together in specific proportions and ground into a raw meal that is heated to produce Portland cement clinker. The clinker is then mixed with relatively small amounts of gypsum (calcium sulphate)—added to slow setting of the cement—and ground into the fine powder that is OPC. It is in these later steps that SCMs and fillers (e.g., limestone) can be added to create specialized cements. This process is illustrated in **Figure 3A-1**, which represents today's state-of-the-art cement-making process., which represents today's state-of-the-art cement-making process.), raw meal is conveyed to the top of a tower that holds a series of 3-6 cyclone separators arranged one above another. As the meal descends through this series of cyclones, it is gradually heated by contacting hot exhaust gases, which are, in turn, gradually cooled. These hot exhaust gases come from burning fuel in the calciner and rotary kiln. Meal is directly heated to around 900 °C by burning fuel in the calciner, which is located near the end of the series of cyclones. Meal passes from there into the rotary kiln, where the meal is finally converted into nodules of clinker at temperatures of around 1,450 °C (and gas temperatures of nearly 2,000 °C). Of the total heat input to the plant, 60-70% occurs in the pre-calciner and the remainder occurs in the rotary kiln.[10,13] The hot clinker exiting the rotary kiln is then cooled, preheating the air that is used in the kiln and pre-calciner.

As this description implies, different temperatures are required in the cement making process and the process is highly heat integrated. This means that the optimal means of providing heat to the pre-calciner may not be the same as in the kiln. In addition, changes that might impact the flow rates of gas in the system must be carefully evaluated, as they may impact the clinker capacity of the plant. Moreover, because combustion gases are in direct contact with the cement, the impact of changes to the fuel composition must be carefully considered to avoid negatively impacting product quality.

Substituting biofuels for fossil fuels

In 2014, coal provided 70% of the direct thermal energy input to cement manufacturing globally, followed by oil and gas at 24% and "alternative" fuels at 6%.[3] The alternative fuel category includes both waste (e.g., municipal solid waste, sewage sludge and hazardous wastes) and bioenergy crops, although waste dominates in energy terms[a]. Where coal is used as the fuel input to the state-of-the-art described earlier, direct emissions from coal combustion contribute around 300 kgCO$_2$-e of the total 900 kgCO$_2$-e of direct and indirect (electrical) emissions for each metric ton of clinker; where gas is used, emissions from fuel combustion fall to 180 kgCO$_2$-

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[a] High temperatures and long residence times in the cement making process make it effective for incineration of waste (and hazardous waste in particular).

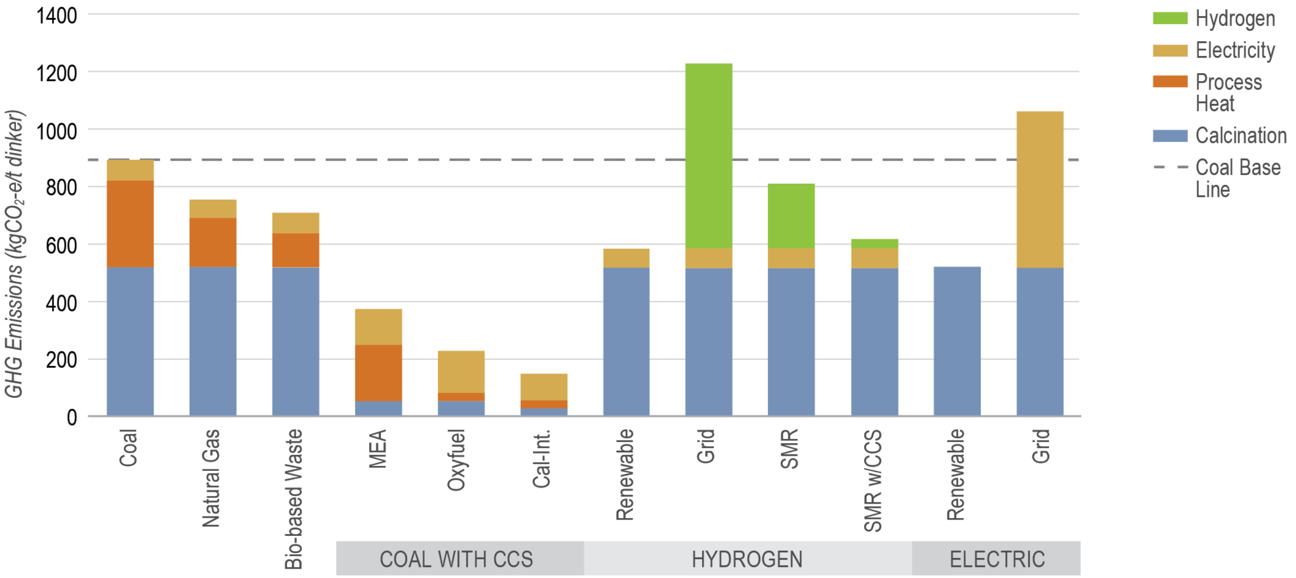

Figure 3A-2. *The greenhouse gas footprint of clinker produced using alternative fuels, coal with CCS options, hydrogen and electricity. These results include combustion emissions from process heat and calcination in the cement plant, generation of electricity, and production of hydrogen (but not upstream emissions from fossil fuels production). The coal baseline and CCS options are based on data presented in the CEMCAP project.*[22]

e/t clinker as shown in **Figure 3A-2**[b]. Switching from fossil fuels to waste materials can result in emissions reductions that vary as a function of the source from which the waste material is derived and how it would have otherwise been disposed. For example, using biomass-based wastes (e.g., wood or agricultural processing wastes) would generally result in the direct emissions from combustion being reduced to zero as, by convention, the CO_2 emitted during combustion was drawn from the atmosphere during growth (as assumed in **Figure 3A-2**). As a result, in the 2017 IEA 2DS scenario, the share of waste (and biomass fuels) used directly in cement manufacturing grows strongly by 2050.[5]

Emissions reductions that might emerge from use of bioenergy crops (e.g., switchgrass, poplar) are somewhat more complicated to evaluate. (See Chapter 2B.) While the direct emissions would also be zero by convention, in reality there is a timing difference between CO_2 emissions and uptake by biomass that can have significant impact for long rotation crops.[23]i.e. the CO_2 released from biofuel combustion approximately equals the amount of CO_2 sequestered in biomass. This convention, widely adopted in life cycle assessment (LCA Further, upstream emissions associated with agriculture (e.g., fertilizers, harvesting and transport) and land-use change are non-zero and should be attributed to the fuel.[24] Waste biomass would, by convention, not carry these emissions burdens. Thus, on a lifecycle basis, use of bioenergy crops for process heat would result in lesser emissions reductions than biomass-based wastes. There is a limited sustainable biomass (both waste and crop-based) available for use in materials or as fuels globally, so there will likely be strong competition for biomass that will limit its cost-effectiveness in practice.[3]

Because biomass-based fuels tend to have a lower energy content (per unit mass) than fossil fuels—or, as will be discussed, hydrogen—they are not suitable for providing the high temperatures required in the kiln directly but can be used in the calciner to provide lower temperature heat. For example, bioenergy crops such as miscanthus, switchgrass, poplar and pine all have a lower heating value of 17-19 GJ/t[25], whereas most kilns require a fuel with a heating value of 20-22 GJ/t at a minimum.[10] Burning alternative fuels in the calciner requires use of multi-channel burners in the calciner and careful monitoring of the levels of impurities, such as chloride, in the clinker.[10] However, these issues are handled in practice today at facilities that burn alternative fuels and

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[b] Assuming an electric grid intensity of 519 gCO_2/kWh,[5] IPCC emissions factors[20] and other energy requirements, as detailed in the CEMCAP base case.[13] These figures do not include the upstream emissions from production and distribution of fossil fuel or mining of raw materials. In the case of natural gas, for example, inclusion of these emissions would increase emissions by around 20% per ton of OPC based on recent estimates of average US natural gas upstream emissions.[21]

do not appear to be a major barrier. A higher degree of substitution of biomass and waste for other alternative fuels could be achieved by gasification of the feedstocks and subsequent use of the syngas (i.e., a mixture of carbon monoxide and hydrogen) as fuel, but this is at the research stage in the cement sector.[11]

Application of CCS to cement making

The potential importance of CCS to reduce emissions from cement manufacturing was recognized by the late-1990s[26] and has been emphasized through successive analyses and road-mapping activities.[3,7,10,11,27] The value of CCS to the cement industry is that it could reduce direct emissions from cement manufacturing—both from process heat and calcination—by 95%[13] the chilled ammonia process, membrane-assisted CO₂ liquefaction, and the calcium looping process with tail-end and integrated configurations. For comparison, absorption with monoethanolamine (MEA and, when coupled with alternative fuels, result in zero (or even negative) emissions. Thus, CCS has an important role to play amongst the multiple emissions mitigation options for the cement industry.

While all three classes of CO_2 capture technology (see Chapter 2D) could be applicable to cement manufacturing, post-combustion and oxy-combustion technologies are seen as the leading candidates.[10] Solvent-based, post-combustion capture technologies (e.g., amine-based solvents, chilled ammonia) can be added to a cement plant without making major modifications to the cement-making process or impacting cement production. However, both require substantial amounts of additional steam that would need to be generated on site (from additional fuel) or imported from neighboring facilities.[13]the chilled ammonia process, membrane-assisted CO₂ liquefaction, and the calcium looping process with tail-end and integrated configurations. For comparison, absorption with monoethanolamine (MEA Amine-based capture systems have been the focus of many engineering studies, and one was successfully pilot-tested by Norcem between 2013 and 2017 at a plant in Norway.[10,13]

In addition to the conventional solvent-based options, calcium looping (CaL) technology has also been investigated for application to cement plants for post-combustion capture. CaL shares many similarities with cement making, as it is a cyclic process in which CO_2 is captured from flue gas using CaO, which results in $CaCO_3$—the same material found in raw meal for OPC—and the CO_2 is then driven off by the same calcination process. The CaL process can be added to the cement plant in either the “tail-end” configuration, which requires no major modifications to the cement making process, or in the “integrated” configuration by using a shared calciner, which entails major modifications to the cement plant. The tail-end configuration has no impact on cement production, while the integrated process could impact cement quality. In both cases, fuel and limestone consumption increases and, depending on the configuration and design choices, the plant could become a net generator of electricity.[13]the chilled ammonia process, membrane-assisted CO_2 liquefaction, and the calcium looping process with tail-end and integrated configurations. For comparison, absorption with monoethanolamine (MEA The CaL process has been demonstrated at MW-equivalent scale for post-combustion capture in power generation,[28,29] is being pilot-tested by Taiwan Cement Corporation[10] and will be further tested in the EU-funded Cleanker Project in Italy.[c]

Oxyfuel technology could also be applied to cement plants by converting the precalciner and, optionally, the kiln to use pure oxygen (rather than air) for combustion of the fuel and by recycling some of the CO_2-rich flue gas to control temperature in combustion. [11,30] This would necessitate changes to the burners in the precalciner and kiln, modifications to reduce air leakage into the system and changes to the clinker cooler, but it requires less significant modifications than the integrated CaL configuration.[13,30] It would require additional electricity (for air separation), but no additional fuel input. The increased concentration of CO_2 in the kiln, precalciner and preheater would impact heat transfer and the degree of calcination of the product (at a constant temperature), which could impact product quality if not appropriately managed.[30] Oxyfuel technology has been pilot-tested at a Lafarge cement plant in 2011 and 2012 in Denmark and has been widely studied.[11,30]

Applying CCS to cement production would reduce the combined direct process heat and calcination emissions from cement making by upwards of 95%. However, the overall reduction depends on the type of capture system applied and the carbon intensity of energy inputs (e.g., supplemental fuel, electricity).[13]the chilled ammonia process, membrane-assisted CO_2 liquefaction,

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[c] See http://www.cleanker.eu/home-page-it.html

and the calcium looping process with tail-end and integrated configurations. For comparison, absorption with monoethanolamine (MEA For example, in the case of a cement plant that uses coal as the primary fuel and natural gas to provide steam for an amine-based capture system (without capture) and draws electricity at the global average emissions intensity, the overall emissions reduction would be closer to 60% (i.e., from 900 to 370 kgCO_2-e/t clinker) as shown in **Figure 3A-2**. On the other hand, the integrated CaL process would reduce emissions by upwards of 80% from a coal-fueled baseline to around 140 kgCO_2-e/t clinker. Unfortunately, these substantial emission reductions would also result in an increase of 50% (MEA) to 80% (integrated CaL) in the cost of clinker production, relative to a state-of-the-art baseline. This corresponds to mitigation costs of \$100 and \$70/tCO_2 avoided, respectively.[12]

None of these CO_2 capture technologies have yet been demonstrated at full-scale on a cement plant. However, this may soon change, as the Norwegian government is investing in development of an integrated CCS project that would capture CO_2 from the Norcem cement plant at Brevik, Norway[d]. If funded, this demonstration project would not only provide valuable information about CO_2 capture in the cement industry, but would also develop the CO_2 transport and storage infrastructure that is currently missing in Europe. The absence of transport and storage infrastructure poses a barrier to deployment of CCS across industries globally and will need to be addressed if this emissions reduction option is to be taken up for cement or any other sector.

Given that the most promising technologies available for capture from cement production are different from those in power generation (e.g., CaL) and, for maximum emissions reduction benefit, should be integrated into the process, continued focused research and pilot testing would be beneficial. For example, the LEILAC project (an EU-funded research project) aims to demonstrate Direct Separation calcining technology for cement manufacture at pilot-scale, in which raw meal is heated indirectly, separating fuel combustion from the calcination process.[31] Other emerging capture technologies, such as molten carbonate fuel cells,[32]necessary for sustaining the endothermic calcination process and the formation of clinker.

Conventional approaches to CO_2 emission reduction in cement plants are based on post-combustion capture with chemical solvents, requiring a substantial energy consumption for regeneration, or oxycombustion in the cement kiln, involving a deep redesign of the plant. The aim of this work is investigating the application of Molten Carbonate Fuel Cells in cement plants for CO_2 capture from the plant exhaust gases, using the fuel cells as active CO_2 concentrators of combustion flue gases and eventually obtaining a purified CO₂ stream through a cryogenic process. A novel configuration with MCFCs added along the exhaust line has been assessed by means of process simulations. The results show a remarkable potential in terms of equivalent avoided CO_2 emissions (exceeding 1000g/kWh may also prove to be an attractive option when integrated into the cement making process.

Use of hydrogen as an alternative fuel

Hydrogen is not currently used as an alternative fuel in cement making, nor has use of hydrogen as an alternative fuel in cement making been widely investigated. While the combustion temperature of hydrogen in air is more than sufficient to provide the temperatures required in the cement kiln, the combustion properties of hydrogen mean that it would need to be burnt in specially designed burners or mixed with solid particles (e.g., clinker dust) to be effective.[33] How use of hydrogen impacts clinker quality also appears to be an open question. Given the state of research on hydrogen for cement making, there may be other unknown issues as well.[33]

Technical challenges of hydrogen combustion notwithstanding, use of green hydrogen generated from electrolysis with fully renewable electricity would eliminate process heat emissions as shown in **Figure 3A-2**—an overall reduction of around 30% relative to a coal-fueled plant. Of course, the intermittent nature of renewables would necessitate energy (or hydrogen storage) to support continuous operation of a cement plant, so alternatives would be to use grid electricity for electrolysis or grey hydrogen from steam-methane reforming (SMR). At the current global average grid intensity, however, the emissions from a plant that uses hydrogen generated using grid electricity would be 1.4 times that of a coal-based plant (**Figure 3A-2**). The grid emissions factor would need to be around 250 kgCO_2/

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[d] See https://www.norcem.no/en/carbon_capture

kWh to achieve the same overall emissions intensity as a coal-fired cement plant and around 180 $kgCO_2$/kWh to meet that of an SMR plant (without CCS). Extending the analysis illustrated in **Figure 3A-2** to include upstream emissions associated with natural gas supply (and renewable generation) would likely favor blue hydrogen (i.e., from SMR with CCS) over electrical routes. This highlights the interlinked nature of hydrogen with decarbonization of the electricity sector.

As in the case of biofuel substitution, use of hydrogen for process heat has no impact on the emissions from calcination or other indirect emissions from electricity generation. Thus, substitution of hydrogen would be limited to a 30% reduction relative to a coal-fired case, all else being equal. This would increase the overall cost of clinker production by at least a factor of three (for green hydrogen) on the basis of fuel alone, making the overall cost of emissions mitigation much higher than for direct application of CCS. Should Direct Separation calcination technology be shown to be viable,[31] it could make hydrogen substitution a more attractive option. Such a combination would allow capture of the calcination emissions, somewhat reducing the mitigation cost. Nonetheless, given the relatively low potential and high cost of emissions reductions through use of hydrogen fuel, it may not be a valuable approach to pursue in a deep decarbonization scenario.

Direct electrical heating

Little has been written about direct electrical heating for cement manufacturing. It should be technically possible to heat raw meal to a sufficient temperature to decompose $CaCO_3$ and form the active phases of cement using electrical-resistance heating (or other methods discussed in Section 2C). As in the hydrogen case, if Direct Separation calcining technology is successful, it would not only allow CO_2 resulting from calcination of the raw meal to be captured in a concentrated form and geologically stored but would also enable efficient use of other heat sources such as electrical-resistance heating. However, Direct Separation calcining (using electricity, or otherwise) would only allow for a partial replacement of process heat with electricity, as it does not replace the rotary kiln. Indirectly heated rotary calciners—i.e., a rotary kiln to which heat is provided by natural gas or electric resistance elements—are manufactured today for specific applications where the atmosphere in the calciner must be controlled, such as pyrolysis. However, the capacity of commercially available rotary calciners are many times smaller than those used in state-of-the-art cement plants and maximum temperatures are somewhat lower (as discussed in Section 2C), suggesting further development is required[e].

For the same energy input, the cost of using electricity directly to generate heat (at nearly 100% efficiency) would be lower than using hydrogen produced via electrolysis (as today, electrolysis at large scales is around 70% efficient).[34] At the same time, in a system that combined Direct Separation calcining technology with an electrically heated rotary calciner, all of the calcination emissions could be captured. This could result in lower overall avoidance cost than the hydrogen routes and could potentially be competitive with current approaches to CCS. However, considerable further research is needed to assess these technologies before any strong conclusions can be drawn.

Conclusion

Manufacturing of cement is a substantial contributor to global GHG emissions. As the demand for cement is projected to grow in the decades ahead, the sector will need to aggressively reduce its emissions to reach levels consistent with a 2 °C or 1.5 °C target.

A wide range of options for emissions reductions have been evaluated, ranging from efficiency improvements to substitution of SCMs for emissions-intensive clinker to changes in the way cement is used in construction. Around 40% of the direct CO_2 emissions from cement manufacturing are associated with process heat for clinker production, while the remainder are generated from decomposition of calcium carbonate in the process. Given that the vast majority of cement is produced using coal for heat today, substitution of lower-carbon intensity fuels is already having a substantial impact. Biomass-based wastes and sustainable biofuels have an important role to play, but they can only substitute for a fraction of the heat input in cement making (due to their low heating value) and, given their limited supply, may not be cost effective in large quantities. Reducing emissions from heating via CCS is an important option that has been researched for many years and is now being demonstrated. While relatively costly in comparison to use of alternative fuels (and other

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[e] For example, indirectly heated kilns are available from IBU-tec, FEECO, and Kurimoto Ltd.

mitigation options), it has the distinct benefit of being able to reduce the total emissions—both process heat and calcination—by upwards of 90%. Use of hydrogen, green or otherwise, as an alternative fuel appears to have less potential, as it is more costly than direct application of CCS in the cement plant and would reduce only the emissions from process heat. Direct Separation technology, however, could enable more cost-effective emissions reductions from hydrogen substitution, direct electrical heating and carbon capture. There may also be options that have not yet been identified in literature to combine fuel substitution with CCS to achieve zero or even negative emission cement.

This case study highlights the challenges of trying to separately address process heat emissions from those resulting from carbon in the feedstock and highlights the need to examine emission-reduction options in industrial processes in an integrated fashion. Continued research, development and demonstration in the area of emissions reductions in cement-making is needed to achieve zero emissions processes.

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IRON AND STEEL

Industry overview

The global iron and steel industry is one of the largest in the world, with sales of $2.5 trillion in 2017.[1] The 2018 production of crude steel was 1,808 million tons, up 7% from 2017 and a 10-fold increase since 1950.[2,3] Steel is one of the largest products by weight produced by humanity—one of very few commodities manufactured at the gigaton scale—and it is used in a vast range of industries including construction, automotive, shipping, aerospace and energy equipment. Because of this enormous scale and the fact that conventional iron and steel production is energy- and emissions-intensive, the sector is responsible for approximately 7% of global CO_2 emissions.[4] Finding practical approaches to decarbonizing iron and steel production is therefore of vital importance to achieving climate goals.

Any successful approach to decarbonizing iron and steel must take into account the fact that the industry is in a state of flux. A decade of rapid expansion and recent demand saturation has led to severe overcapacity, with average plant use at approximately 75%. If all planned steel production projects are realized, global capacity could increase by 4-5% between 2019 and 2021, putting further pressure on use.[5,6] Steel production has also been increasingly concentrated, with 51% of 2018 production in China (up from 38% in 2008), while India, Japan, the US, Korea and Russia collectively account for an additional 25%. Meanwhile, steel consumption averages 200 kg per capita globally but varies from a low of 30 kg per capita in Africa to a high of 283 kg per capita in NAFTA countries. Since trade is global, with exports equal to 27% of production in 2018, prices are strongly affected by global competition.[2]

Decarbonization pathways

The two main processes used to produce steel are the older blast furnace/basic oxygen furnace route (BOF) and the newer electric arc furnace route (EAF) (see **Figure 3B-1**). The BOF route begins with raw iron ore and includes many processing steps. For this reason, it is usually performed at relatively large integrated steel mills that also incorporate facilities for sintering iron ore and producing coke from coal. The EAF route primarily uses recycled steel scrap as its feedstock and includes fewer processing steps. It is therefore usually performed at smaller, "mini-mill" facilities where steel scrap is widely available.

The dominant energy requirement in producing virgin steel is extracting metallic iron from raw iron ore (smelting). In the BOF route, this is performed at blast furnaces, which consequently have very high emissions. Steel that has already been produced and recycled as scrap can be reprocessed via the EAF route without this step, leading to very large energy and emissions savings (as much as 90% reduction[8]). Additionally, since EAF is almost entirely electrified, powering it with low-carbon electricity can almost entirely eliminate its emissions.

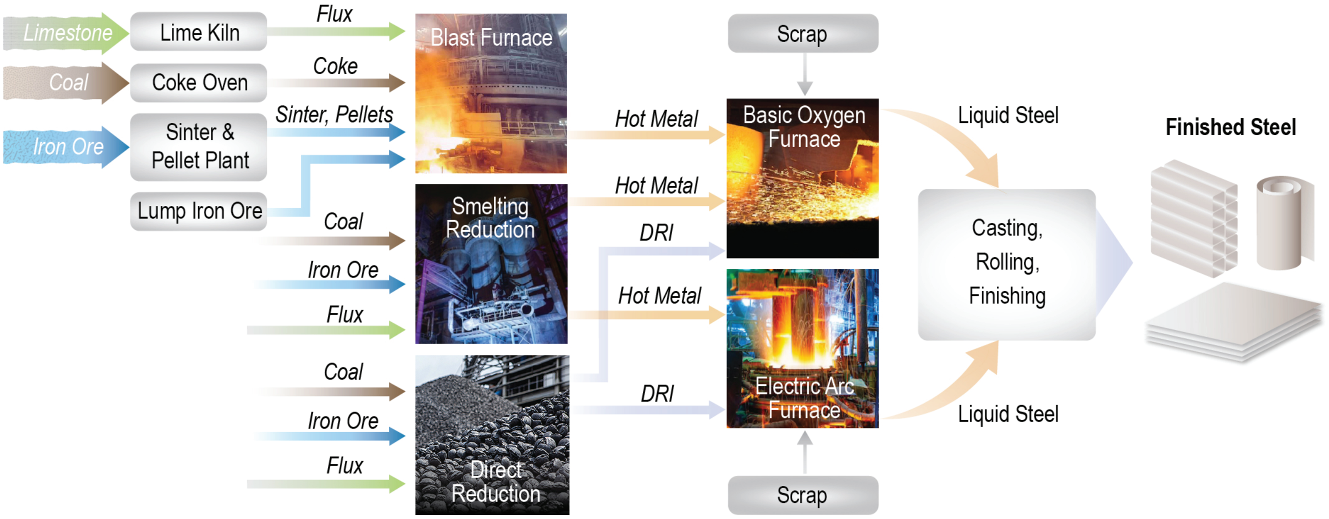
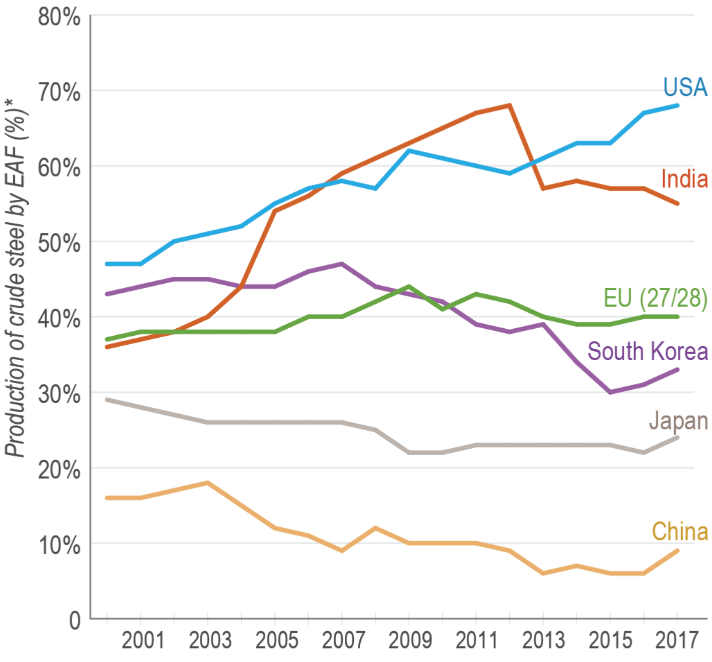


Figure 3B-1. *Primary iron and steelmaking routes (adapted from Carpenter et al[7]). While both BOF and EAF routes can use hot metal, scrap and DRI as feedstocks, BOF primarily uses hot metal while EAF primarily uses scrap.*

As a result, the transition from BOF to EAF results in significantly reduced emissions. Globally, BOF accounts for approximately three-quarters of steel production and EAF for one quarter, down from its peak of 33% in 2000. The balance between BOF and EAF varies dramatically within different countries, mostly as a result of the availability of scrap steel and reliable, low-cost electricity (see **Figure 3B-2**). For example, due to the long history of steelmaking in the US and Mexico and the large amount that is recycled, two-thirds of steel production is via EAF. The average emissions intensity of steel production is therefore relatively low at 1,736 kg CO_2/ton (US) and 1,080 kg CO_2/ton (Mexico).[3,9] (The local electric grid emissions intensity also impacts these values.) In China over 90% of steel production is via BOF, and the average emissions intensity is correspondingly higher at 2,148 kg CO_2/ton crude steel.[9,10]

In considering the possible future adoption of EAF (displacing BOF), it is instructive to note that the stock of steel per capita has historically saturated at 11-15 tons in countries that have fully industrialized.[11] However, understanding the stock of steel and the amount available for recycling is complex and would benefit from additional research.[12] A scenario analysis of steel production based on mass flow analysis suggests that the last required blast furnace for primary steel production could be built as early as 2020.[13]



*Steel Statistical Yearbook 2018 and Steel Statistical Yearbook 2010

Figure 3B-2. *Share of steel production via EAF in different region/ countries; data from worldsteel.*[14,15]

While the EAF route primarily uses recycled steel scrap, it is able to produce virgin steel using direct reduced iron (DRI) as a feedstock. DRI processes iron ore to a metallic iron suitable for the EAF route, but it avoids the use of coke, significantly reducing its emissions. Expanding the use of DRI for EAF steel production is therefore a potential route to low-carbon virgin steel production. (See below for further discussion of DRI.)

Process heat in iron and steel making

It is important to note that while both BOF and EAF require large amounts of process heat, the two routes

BOX 3-2 BOF vs EAF in China

Because EAF steel production is so much less emissions-intensive, transitioning from BOF to EAF can lead to very large emissions reductions. However, doing so requires significant capital investments and confidence that there will be a sufficient supply of recycled scrap steel available. This is of particular interest in China, where steelmaking is dominated by BOF (see Figure 3B-2) but where there are signs of a growing availability of scrap steel in the medium-term. This issue has been underscored by a recent surge in available scrap steel due to the shuttering of inefficient induction furnaces. However, many Chinese BOF facilities (particularly blast furnaces) are relatively new and efficient, making their replacement less economically attractive. The evolution of BOF vs EAF steelmaking in China will be an important driver of global industrial emissions over the next several decades.[5,16]

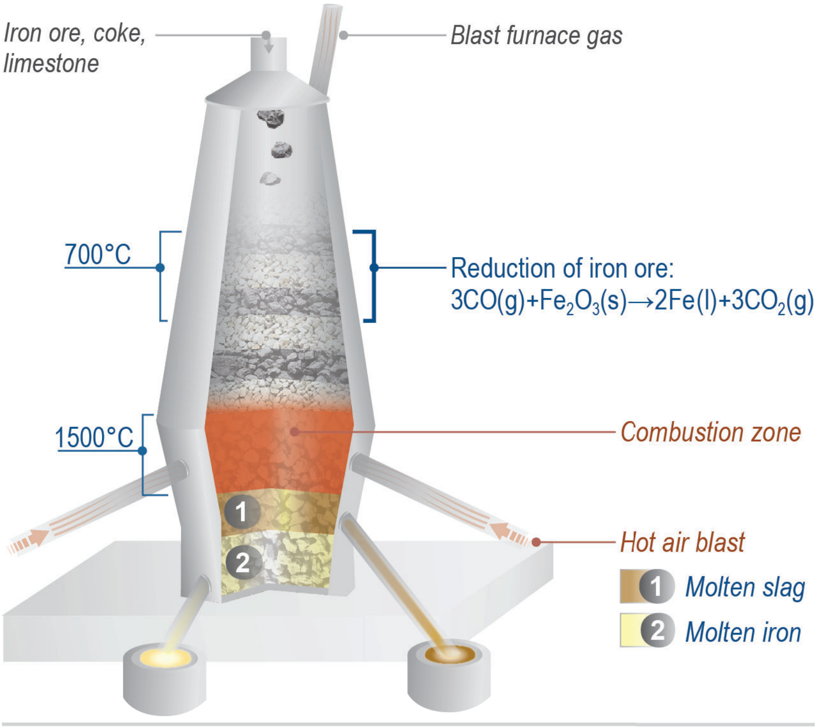


Figure 3B-3. *Blast furnace for ironmaking. Iron ore, coke and limestone are added in layers at the top, sinking slowly to the bottom. Hot air is blasted into the furnace, igniting the coke in the combustion zone and producing CO gas and heat. Coke also physically supports the descending layers of iron ore and provides porosity for movement of CO gas and liquid iron.*

generate it in very different ways. In BOF steelmaking, process heat is provided through the combustion of coke. Coke also serves three other functions: chemical reduction of iron ore, physical support of the burden in blast furnaces, and porosity for hot gas and molten metal movement (see below). This multi-purpose role of coke means that simply replacing coke combustion with other sources of process heat is impractical. In EAF steelmaking, process heat is provided electrically, which also makes direct replacement unappealing as an emissions-reduction strategy and also unnecessary to the extent that the electricity comes from low-carbon sources. The complexities of process heat in iron and steelmaking therefore generally require significant process change to decarbonize.

While EAF offers many advantages, BOF steelmaking will continue to be a large share of global production. There is also a large installed base of blast furnaces and related equipment that represents a large investment of capital. Finding technical methods to reduce emissions intensity of the BOF route without major process changes is therefore of great interest and will form the bulk of the discussion to follow.

Process description: BOF

BOF steelmaking is used to produce new steel from raw iron ore and other ingredients. The first step in the process is to combine iron ore—primarily magnetite (Fe_3O_4) and hematite (Fe_2O_3)—with limestone and fine particles of coke (coke breeze) in a process known as sintering. The coke is ignited and burns at 1,300-1,480 °C, partly melting the materials and producing a coarse agglomerate called sinter that is appropriate for bulk handling. The heated sinter is usually cooled in open air or with water sprays; waste heat recovery is technically feasible but rare.[17,18]

In parallel to sinter production, metallurgical-grade coal is heated in the absence of air at 900-1,100 °C to produce coke. The heating drives off volatiles and leaves a nearly pure carbon mass that is both porous and structurally strong. Heat is provided by combusting a portion of the coke oven gas (COG), the remainder of which is usually used in other combustion units at an integrated steel plant. At an integrated steel mill, both sintering and coking facilities are usually co-located with the rest of the iron and steel making facilities because of their importance to the iron and steel making.[9,19]

The sinter, coke, additional pellet or lump ore, and limestone are then fed to a large blast furnace for the iron smelting process (see **Figure 3B-3**). The furnace is charged with materials from the top, which form alternating layers and sink slowly towards the bottom. Water-cooled nozzles (tuyeres) inject air heated to 900-1,300 °C near the bottom. This blast air is heated in hot blast stoves, which primarily burn top gas recycled from the blast furnace, possibly with the addition of some coke oven gas.[20] This hot blast air burns the coke, forming carbon monoxide (CO) and heating this combustion zone to 1,500 °C or higher. Fuel combusted for heating the hot blast stoves results in the majority of CO_2 emitted from a blast furnace.[7]

The hot CO rises through the furnace and reacts with the sinking iron ore, chemically reducing it to iron and CO_2. The heat also decomposes the limestone into lime (CaO) and CO_2; the lime in turn reacts with trace silicon impurities to form calcium silicate ($CaSiO_3$) slag. The molten iron and slag sink to the bottom of the furnace where they are tapped, while the CO_2 and other hot gases (known collectively as "blast furnace gas") rise to the top where they are used for a variety of purposes, including pre-heating the tuyere blast air and generating electricity.

A key feature of the blast furnace is the alternating addition of charge materials to the top, which form layers that slowly sink. They are partly supported on the coke, which is structurally strong and slows their descent, while also being porous enough to allow molten metal to flow downwards and hot gases to flow upwards. This allows for a long-duration interaction within the furnace (counter-current flow), optimizing the chemical reactions.

The iron that is tapped from the bottom of the blast furnace is called pig iron or hot metal. It is mostly pure iron, with a relatively high carbon content (approximately 4%) compared to finished steel. At integrated steel mills, it is transferred directly into a steel-making furnace, along with up to approximately 30% scrap steel. Within the steelmaking furnace, a water-cooled lance injects pure oxygen, which reacts with the remaining carbon in the hot metal, providing heat and reducing the total carbon content. The resulting molten steel and slag are then tapped at periodic intervals. In contrast to the blast furnace, the steelmaking furnace requires no additional heat input because all of the necessary heat is provided by the oxygen-carbon reactions.

Emissions reduction in the BOF route

The CO_2 emissions from BOF come from a wide variety of sources (see **Figure 3B-4**). The largest share (39%) is from flue gas emitted from power generation. However, this generation is based on combusting blast furnace gas (BFG) and coke oven gas (COG), complicating the attribution of these emissions (some natural gas may be combusted as a supplementary fuel). The next largest share is from the stoves that heat air for injection via the tuyeres in the blast furnace (18%), with important contributions from the sinter plant and coke plant (both 16%).[7] However, the hot air stoves, coke ovens and sinter plant also combust large portions of BFG and/or COG, illustrating the close process integration of the overall BOF process.

While these are all process heat contributions to emissions, replacing any one of them with an alternative process heating method, such as combusting hydrogen or providing electric heat, would disrupt this integration. This would lead to a need to handle excess BFG and COG that is no longer being combusted, or (in the case

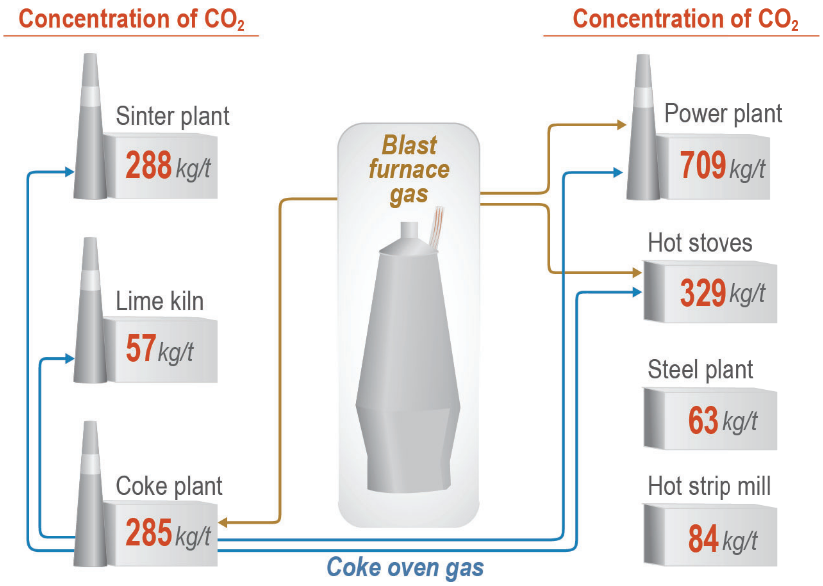


Figure 3B-4. *CO2 emissions from different processes within BOF steelmaking. Adapted from Carpenter, 2012.*[7]

of coke oven modifications) reduce the amount of COG available for use by various processes. This integration makes piecemeal process heat modification unattractive for BOF technology and leads instead to an examination of carbon capture (see below) or options that favor material substitution in the process, which include:

- **Reduction or elimination of sinter in favor of pelletized ore for charging blast furnaces:** Because sinter production has a relatively high emissions intensity, reducing or eliminating it in favor of pelletized ore significantly reduces emissions.[21] This requires no capital investment or process changes for blast furnace operation and can improve overall blast furnace performance.[22]
- **Substituting biomass-derived charcoal for coke in blast furnace charge, sintering and/or tuyere injection:** Charcoal derived from processes such as autothermal pyrolysis of biomass can potentially replace or substantially substitute for the use of coal-derived coke in blast furnaces, providing a source of carbon for combustion, structural strength to support charged materials and sufficient porosity. Treated biomass could also be used as a coke substitute in other steps of the BOF route. This would require investment in pyrolysis equipment and establishment of a reliable biomass supply, but minimal or no changes to blast furnaces.[23] Biomass substitution for coke has an estimated emissions reduction potential of 32-58% for the BOF route.[24] Based on a variety of factors including the availability of sustainable sources of biomass, the most suitable countries for biomass substitution in iron and steelmaking are Canada, Sweden, China, the US and France.[25]
- **Modification of the coking process:** There are a variety of approaches to reducing emissions from coking ovens, including single-chamber-system (SCS) coking—which uses single, large-volume ovens to achieve high thermal efficiencies—and coke oven under-firing with advanced diagnostics to improve heating efficiency.[9]
- **Reducing coke use through pulverized coal and hot oxygen injection to the blast furnace:** This technique substitutes a fraction of blast furnace coke consumption with direct coal injection (bypassing the coke-making process) and can achieve good combustion with additional oxygen injection.[9]
- **Reducing coke and coal use through co-injection of hydrogen:** The CO_2 Ultimate Reduction in Steelmaking Process by Innovative Technology for Cool Earth 50 (COURSE50) program in Japan has experimented with the use of hydrogen reduction in blast furnaces to reduce coke consumption and emissions. Using coke oven gas, either directly or reformed to increase the hydrogen content, the program demonstrated hydrogen reduction at a test blast furnace in Luleå, Sweden.[26] Germany-based steelmaker thyssenkrupp has recently announced tests of hydrogen injection in a blast furnace to substitute for coal dust as a reductant.[27]
- **Improving hot blast stove operation:** A number of techniques can be used to improve stove efficiency, including air pre- or super-heating (see below), use of ceramic burners, and staggered airflow through multiple stoves.[7]
- **Optimizing blast furnace operation using modeling and simulation with high-performance computing:** Observing conditions within the blast furnace during operation is difficult, so precise control over the process, including optimized injection of coal and charge, is not usually achieved. Simulations using computational fluid dynamics can improve the understanding of blast furnace processes and lead to process optimizations.[28]
- **Plasma torch super-heating of hot blast air:** Plasma torches use an electric arc to convert a working gas to a plasma, achieving temperatures of approximately 5,000 °C. Introducing a plasma torch using BFG and low-carbon electricity to superheat hot blast air could reduce the total coke use of the BOF route.[29]

Process description: EAF and DRI

In EAF steelmaking, a refractory-lined vessel is first charged with a mixture of steel scrap and DRI. Graphite electrodes within the vessel are powered with either AC or DC electric current, and an electric arc forms between the electrodes and the charge material. The material is heated both through resistive heating from the passing electric current and radiant heating from the arc, which can reach temperatures of 3,000 °C. EAF vessels range from a few tons to hundreds of tons per charge, using transformers that range from 10 to 300 MVA and currents of up to 100 kA or higher. Depending on furnace design and the charge properties, approximately 1.6 GJ of electrical energy is consumed per ton of melted steel.[7,9]

EAFs are usually charged with scrap but can also accept DRI or even pig iron as part of the charge (see **Figure 3B-1**). DRI is produced by reducing iron in solid form (without melting), most commonly using a hydrogen-carbon monoxide mixture (syngas) produced by reforming natural gas as a reducing agent; no coke is required. Multiple processes exist, but approximately two-thirds of global DRI production (100.5 Mt in 2018) uses the MIDREX process, with HYL/Energiron representing 15.5%.[30] The emissions benefits come from two distinct properties of natural gas in ironmaking: the emissions intensity per unit of thermal energy from combustion is nearly half that of coal, and methane as a reducing agent is twice as effective as carbon on an emissions basis.[31]

India manufactures the largest amount of DRI globally, and primarily uses a process based on combusting and gasifying low-grade coal to produce CO as a reducing agent. The coal-based DRI process is suitable for smaller production units but has higher energy intensity. Multiple types of reactors are used, including shaft furnaces, rotary kilns and fluidized bed reactors.[7]

Medium- to long-term decarbonization options involving significant process change

A number of alternative iron-making processes have been developed and/or are in the process of development. These involve substantial process changes and generally seek to reduce or eliminate the use of coke and blast furnace technology broadly. These approaches include the following:

- **Expanded use of smelting reduction for hot metal production:** Smelting reduction processes iron ore to hot metal in two stages. Ore is charged to a reduction shaft reactor where process gases that are produced from the melter-gasifier reactor mostly reduce the ore to DRI. The DRI is then moved to the melter-gasifier with discharge screws, and the final reduction and melting processes take place there. The two most commonly used processes are COREX and FINEX, the latter of which is able to charge ore without agglomeration. No coke is required in the process, yielding important emissions savings.[9]
- **Upgraded smelting process:** The HIsarna process has been developed within the Ultra-Low Carbon Dioxide Steelmaking (ULCOS) framework as an integrated hot metal production method. This process combines multiple processes in a single cyclone oven, avoiding the use of coke or the need to sinter ore. Ore and lower-grade steam coal are fed to the reactor, which is also able to accept a significant fraction of scrap and biomass. Tata Steel has demonstrated the process at a pilot plant in the Netherlands.[32]
- **Biomass-nugget smelting:** US-based Carbontec Energy Corporation is developing an alternative smelting technology that packages ore, biomass and limestone in compact “nuggets” (briquettes) that are then heated. This pyrolizes the biomass and leads to reduction of the ore, without the use of coke or sintering.[33]
- **Expanded use of hydrogen reduction of iron ore:** Several processes, including HYBRIT and H2FUTURE, are being developed to use hydrogen as a reducing agent for iron ore. The product would be DRI and, when this is combined with EAF steelmaking using low-carbon electricity for hydrogen production from electrolysis, the resulting process can have very low emissions intensity. When charging the EAF with 25% scrap, emissions from this route would be lower than the BOF route for grid emissions intensities below 661 $kgCO_2/MWh$.[34] Hydrogen reduction has the advantage of significant operational flexibility, since electrolyzers can be ramped up and down to follow variable renewable generation.[35]
- **Electrolytic steel production:** Many metals, including aluminum, zinc and nickel, are produced at scale using electrolysis. Steel production has been demonstrated using this technique, with molten oxide as the electrolyte (which is able to withstand the operational temperature of 1,600 °C) and carbon-free anodes. The emissions savings from this technique fundamentally come from eliminating a carbon-based reductant (such as CO) and using electricity directly instead. Technology developed at MIT and commercialized by Boston Metal, as well as the ULCOWIN process, present pathways to electrolytic steel production.[9,36]

Integrating CCS into iron and steel making

Carbon capture from flue gas at a BOF integrated steel mill has substantial technical potential for reducing overall emissions. Santos et al. examined three such scenarios: two based on post-combustion capture technology using a conventional solvent (monoethanolamine, MEA), applied to the flue gas from the hot stoves and steam generation plant (resulting in 50.1% overall reduction in CO_2 emissions), with the

Case	Gas streams treated	CO_2 reduction	Break-even cost ($/t HRC)	Cost of CO_2 avoided ($/t)
Reference	None	0%	$575	N/A
Post-combustion A	Hot stoves, steam plant	50%	$652	$74
Post-combustion B	Hot stoves, steam plant, coke oven, lime kiln	60%	$678	$81
OBF	Blast furnace gas	47%	$630	$57

Table 3B-1. *CO_2 emissions reduction, break-even costs and cost of CO_2 avoided for a BOF reference scenario and three carbon capture scenarios.*[37]

higher-capture scenario also treating flue gas from the coke ovens and lime kilns (resulting in 60.3% overall reduction in CO_2 emissions); and a final scenario based on an oxygen-blown blast furnace (OBF) in which capture using a solvent blend (methyldiethanolamine, MDEA, with piperazine, PZ) is deployed on the BFG (resulting in 46.5% overall reduction in CO_2 emissions) (see **Table 3B-1**).[37] The use of carbon capture increases the break-even price of steel production (without subsidies) from $575/t hot rolled coil (HRC) to $652/t HRC and $678/t HRC, respectively, in the first two cases (post-combustion), and to $630/t HRC in the third case (OBF). These costs correspond to CO_2 avoidance costs of $74/t$CO_2$, $81/t$CO_2$ and $57/t$CO_2$, respectively. The relatively low value of the OBF case is primarily due to a significant reduction in coke consumption and corresponding emissions reduction from the coke ovens. In all three cases, cost increases were driven by increased consumption of natural gas (due to increased plant energy consumption, although energy consumption increase was almost negligible in the OBF scenario) and investment cost for capture equipment.

Several research projects are underway to demonstrate CCS for BOF ironmaking. The COURSE50 program in Japan has focused on developing chemical and physical adsorption technologies for capturing CO_2 from BFG, and is targeting a cumulative CO_2 emissions reduction of 30% when combined with co-injection of hydrogen (see above, and **Figure 3B-5**).[38] By developing new sorbent materials, the project has reduced the energy requirements for regeneration and has enabled the use of facility waste heat (e.g., from slag, hot stove gas, etc.).

The ULCOS consortium has pursued the development of carbon capture from BFG through the concept of Top Gas Recycle-Blast Furnace (TGR-BF). This technique replaces hot blast air with pure oxygen and recycles BFG after capturing CO_2 for re-injection into the blast furnace; it has demonstrated savings of 20% or greater in CO_2 emissions.[39] RIST and POSCO in South Korea have demonstrated the use of aqueous ammonia solvents and low-grade waste heat to capture CO_2 from BFG.[40]

The dominant DRI process, MIDREX, could potentially accommodate CO_2 capture from the slip stream of recycled top gas using pressure swing adsorption (PSA). However, this would require additional process changes and has not been demonstrated. By contrast, CO_2 capture is an integral part of the existing HYL/Energiron process and is in commercial operation at the Al Reyadah facility in the UAE, where captured CO_2 is used for offshore EOR. However, in general this process only reduces overall emissions per ton of steel

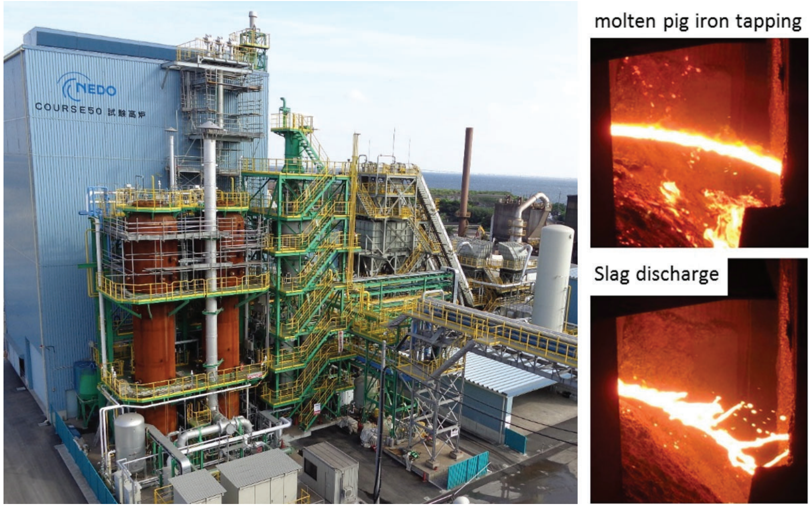


Figure 3B-5. *The COURSE50 program in Japan has focused on developing chemical and physical adsorption technologies for capturing CO_2 from blast furnace gas. Credit: NEDO.*

by 25-35%, assuming average grid emissions intensity for the associated EAF.[37,41] The FINEX smelting reduction process produces low-nitrogen tail gas that is compatible with CO_2 capture with no substantial process changes, although the overall emissions reductions per ton of steel are likely to be less than 50%.[37,42]

Conclusions: Addressing process heat in iron and steel making

- Both the BOF and EAF routes require substantial amounts of process heat, but that heat is generated in very different ways.
- EAF emissions are almost entirely due to electricity generation (because the process is essentially fully electrified), so the production of low-carbon process heat is directly linked to the supply of low-carbon electric power.
- The BOF route generates heat by combusting coke derived from metallurgical coal. The process is highly integrated, with the use of off-gases such as blast furnace gas (BFG) and coke oven gas (COG) for various heating operations, including hot blast stove heating and power generation. It is therefore not practical to replace any individual heating unit operation without a larger process redesign.
- There are a range of options to reduce emissions in the BOF route, including the use of biomass, plasma superheating of blast air, reducing sinter and hydrogen injection.
- Emerging iron-making processes such as smelting reduction and direct-reduced iron (DRI) offer more flexibility in options to provide low-carbon heat. However, they are incompatible with conventional blast furnace technology and represent a substantial process change.
- CCS offers a route to substantial emissions reduction from conventional (BOF) steelmaking. Capture can be applied to various flue gas streams at an integrated steel mill or BFG. Some smelting reduction and DRI processes are highly amenable to carbon capture, while others will require more research.

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CHEMICALS

Industry overview

The global chemical sector (including petrochemicals and refining) is enormous and varied. Total sales in 2017 were $4 trillion.[1] The chemical sector has grown rapidly over the past decade and is projected to continue growth for many years.[2] In 2017, the chemical sector vented ~1.6 Gt CO_2, roughly 3% of global CO_2 emissions. Energy demand was greater for chemicals than for either cement or steel, reflecting enormous heat consumption (**Figure 3C-1**).[3]

The chemical sector represents the largest fraction of US industrial production and GHG emissions. Chemical and refining industries respectively emit 177 and 184 million tons CO_2e annually—roughly 25% of total US industrial CO_2 emissions—with 28% concentrated in Texas and Louisiana[a]. To achieve key climate goals, practical approaches to decarbonizing chemical production is of vital importance.

Unlike cement or steel production, which produce a small number of commercial products, the chemical sector produces an enormous variety of different products using different processes. These include drop-in fuels (e.g., gasoline, diesel, jet fuel, bunker fuel), relatively simple feedstocks and compounds (e.g., ethylene, methanol) and complex products (e.g., lubricants, carbon fiber). The variety of production methods and products complicates strategies for decarbonization.

Similarly, most chemical facilities have a wide set of feedstocks and fuels. Refineries consume natural gas, natural gas liquids and heavy hydrocarbons (e.g., bitumen, asphalt) which serve as feedstocks as well as fuels. Hydrogen is also an important feedstock. In the US and EU, hydrogen production and dedicated pipelines tie directly to refining and chemical facilities. In OECD countries, natural gas is the predominant heat fuel and feedstock, while in China, India and Southeast Asia, coal provides a large fraction of both heat and hydrogen.

Complexities of Operation

The complexity of the chemical sector is matched by the complexities of facility operation. The range of chemical production processes is extremely varied, including the Haber-Bosch process (ammonia), methanation (methanol production), ethylene cracking (ethylene) and pyrolysis of heavy crude (carbon black production). Many of these reactions require fit-for-purpose reactors that cannot be readily replaced.

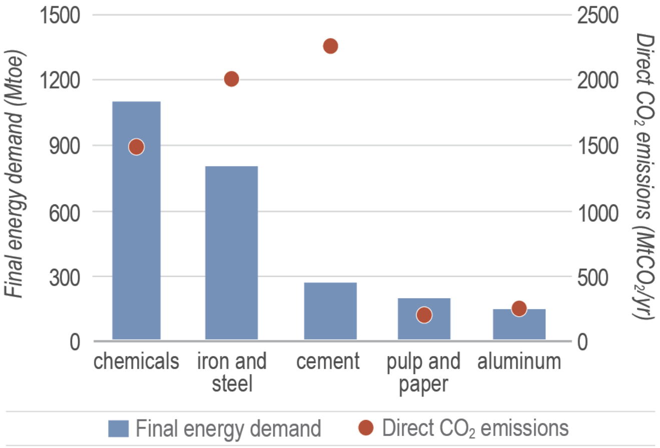

Figure 3C-1. *Global energy demand and direct (process) CO_2 emissions by sector, 2017. Source: IEA.*[3]

In general, many chemical applications require heat that is relatively low in temperature (300-600 °C) compared to other industries. This could open more potential sources of low-carbon heat to application, including advanced nuclear systems or advanced electrical heating (e.g., induction or radiative heating approaches). This is particularly true for systems that require steam as a primary feedstock (e.g., ethylene cracking), since boilers and steam generators today operate on a wide range of heat fuels and inputs. While the temperature range for chemical applications is lower than for cement, steel and glass, the temperatures are generally too high for conventional low-carbon heat systems (i.e. heat pumps).

A concern specific to the chemical industry is the broad distribution of heat sources. Unlike in cement and steel, where most of the emissions flow from one or two large reactors (e.g., a kiln or blast furnace), it is unusual to find a single large source in most chemical plants—there are exceptions, e.g. catalytic crackers for fuel refining and synthesis. Large chemical plants have dozens or even hundreds of small emissions sources tied to heat production, including burners, furnaces and boilers. Decarbonizing these small, distributed sources would likely add complexity and cost to plans for heat supply substitution. As such, potential substitutes for low-

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[a] See https://www.epa.gov/ghgreporting/ghg-reporting-program-data-sets

carbon heat may be limited by the breadth and diversity of heat consumption in a plant. Moreover, some large process units (e.g., catalytic crackers, carbon black synthesis units) generate heat by partial oxidation and combustion of feedstocks and fuels in the key reactions. This limits the kind of substitutions that are possible, since the core process reactions require carbonaceous fuels and feedstocks.

To limit our investigations and focus on representative sectors, we selected two pathways for discussion: ammonia, which chemically contains no carbon, and methanol, which does. Both are large sub-sectors of the chemical industry. Both are globally-traded commodities with mature supply chains and technologies. In this way, both pathways are representative of the chemical sector as a whole, and specific issues and processes within each provide some insight into both the challenges and potential solutions to decarbonizing heat and production across other chemical supply chains.

Ammonia

Ammonia is a huge global industry. It underlies almost all fertilizer production (450 million tons, $156 billion market) and is the largest single commodity within that market, roughly 170 Mt worth $50 billion in 2017.[6] Global CO_2 emissions from ammonia are roughly 1.5% of global emissions (~490 MT in 2012).[7] In the US, 12.5 million tons of ammonia worth $13.2 billion came from 34 facilities in 2018, mostly concentrated in Texas, Oklahoma and Louisiana (in large part due to low-cost natural gas and associated low-cost hydrogen production), resulting in 11.8 million tons CO_2 annual emissions.[6,8] Annual market growth in the US is about 2.5%, and global annual growth closer to 4%. Some recent analysis has proposed ammonia as either a hydrogen storage and transportation medium or as a potentially carbon-free fuel option.[9] If either option entered the market at scale, there would be dramatic increase in ammonia production.

Almost all ammonia production worldwide uses the Haber-Bosch process, invented and developed largely from 1900 to 1910.[10] The core process involves breaking the triple bond of nitrogen gas (N_2) and reducing it by adding hydrogen to form ammonia (NH_3). The triple bond is very strong, so much energy is required to undertake ammonia synthesis. The process operates at very high pressure (2200-3600 psi/15-25 MPa), which requires a lot of compression and mechanical work, expensive capital equipment, and a fairly high temperature (400-500 °C), which requires substantial heat[b].

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[b] To learn more about the Haber-Bosch Process, see: https://www.sciencedirect.com/topics/engineering/haber-bosch-process (Science Direct, 2019, The Haber-Bosch Process)

BOX 3-3 Synthetic fuels and chemicals production in China and India

A very large share of today’s chemical market is in China, India and Southeast Asia.[2] In these regions, access to natural gas as a feedstock is often limited, especially in China, India, Vietnam and Indonesia. In contrast, coal and petcoke are often abundant and very cheap. This has led many chemical facilities in these countries to use solid carbon fuels for heat and also for hydrogen production. Many of these individual facilities are very large and clustered in key regions (e.g., Ningxia and Ahmedabad)[4,5] and would require very large supplies of low-carbon heat and feedstocks to decarbonize.

One feature of these facilities is that hydrogen production commonly occurs through coal or petcoke gasification combined with water-gas shift. This produces a very large byproduct (process) stream of concentrated CO_2, which could be captured and stored for relatively low cost. Unfortunately, none of the countries in question have announced or executed serious plans to capture and store CO_2. Also, in many of these regions, water is scarce and agriculture is limited. As such, solid biomass or biomethane substitution for heat is not a likely option today.

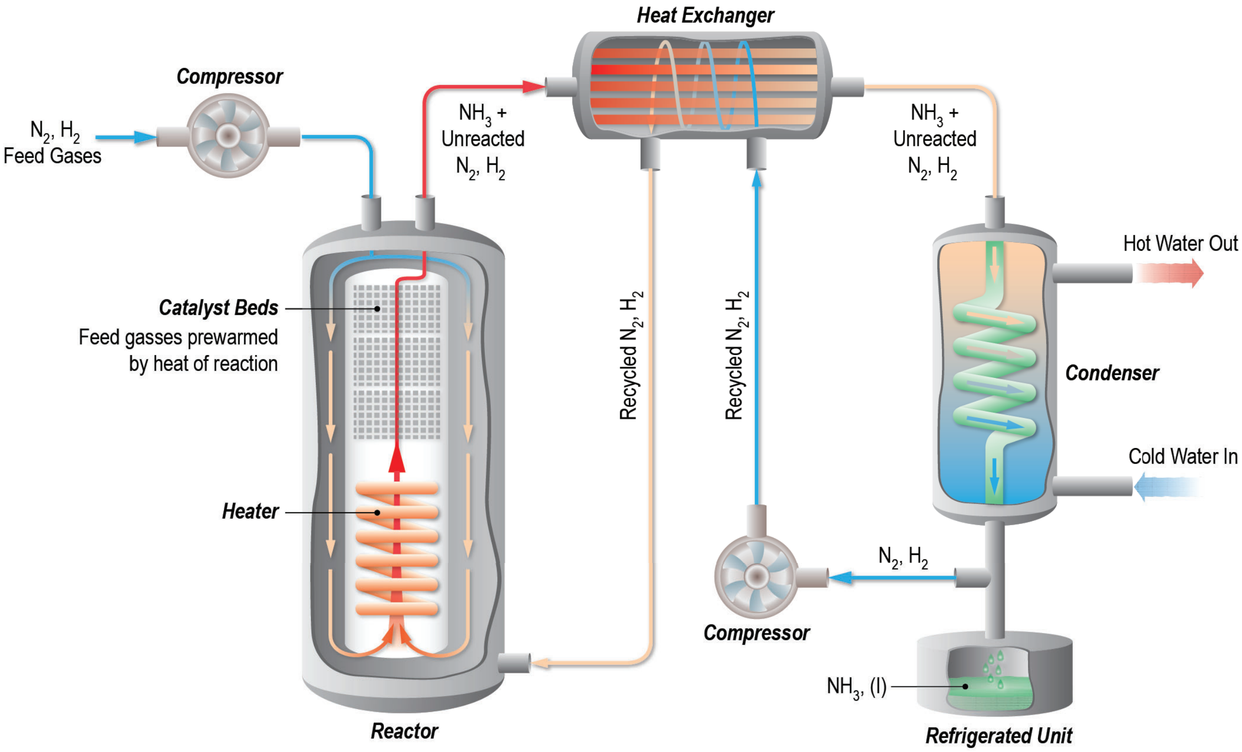

Figure 3C-3. *Simplified cartoon of Haber-Bosch process.*

The power and heat requirements have driven efficiency improvements industry wide, and the industry has reduced energy requirements 75% since 1930 and roughly 40% since 1970.[11] Global average footprint of ammonia production is estimated to be 1.9 tons CO_2/ton ammonia, with ammonia made from natural gas having a footprint of 1.1 tons CO_2/ton ammonia.[12] Over 50% is associated with hydrogen production and roughly 30-40% from process heat. Hydrogen is a critical feedstock to ammonia synthesis, and roughly 50% of global hydrogen production goes into ammonia production. Hydrogen is commonly made from natural gas or longer hydrocarbons at high temperature, which itself consumes much heat during production. (See Chapter 2A). The hydrogen and nitrogen gases run over multiple beds with iron-based catalysts followed by cooling (and heating) in between. Each catalyst executes one component of the chemical reaction, and the multiple beds are used to increase selectivity and yield.

The major consumers of heat are hydrogen synthesis (steam-methane reforming [SMRs]) and the ammonia synthesis reactor. Because heat is a major cost to ammonia production due to multiple heating and cooling steps, most facilities attempt to capture waste heat through a set of heat exchangers (**Figure 3C-3**). The multiple steps for ammonia synthesis require additional heat to provide energy to upgrade/reduce nitrogen during each run across catalytic beds (**Figure 3C-4**).

Methanol

Like ammonia, methanol is a huge global industry and internationally traded commodity. It is used both as a fuel and as a feedstock, usually for plastics, fuels or more complex chemicals (e.g., formaldehyde, gasoline and dimethyl ether). The global methanol market produced 110 million tons worth $24.7 billion[14] at over 90 plants worldwide[c]. Global CO_2 emissions from methanol are ~100 Mt in 2016.[15] About 12 million tons[16] of methanol worth ~$3.6 billion[17] came from US facilities, mostly in Texas and Louisiana. Global annual growth is closer to 7.7% and is projected to grow at an 11% rate, reaching $48 billion in 2024. This demand will be met in part from new production and export facilities in the US.[17]

Originally, methanol was derived from wood and was known as wood alcohol. Today, methanol is typically made by feeding syngas into a methanol synthesis unit followed by distillation (**Figure 3C-5**). Both CO and CO_2 can be converted to methanol, although CO_2

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[c] See https://www.methanol.org/the-methanol-industry/

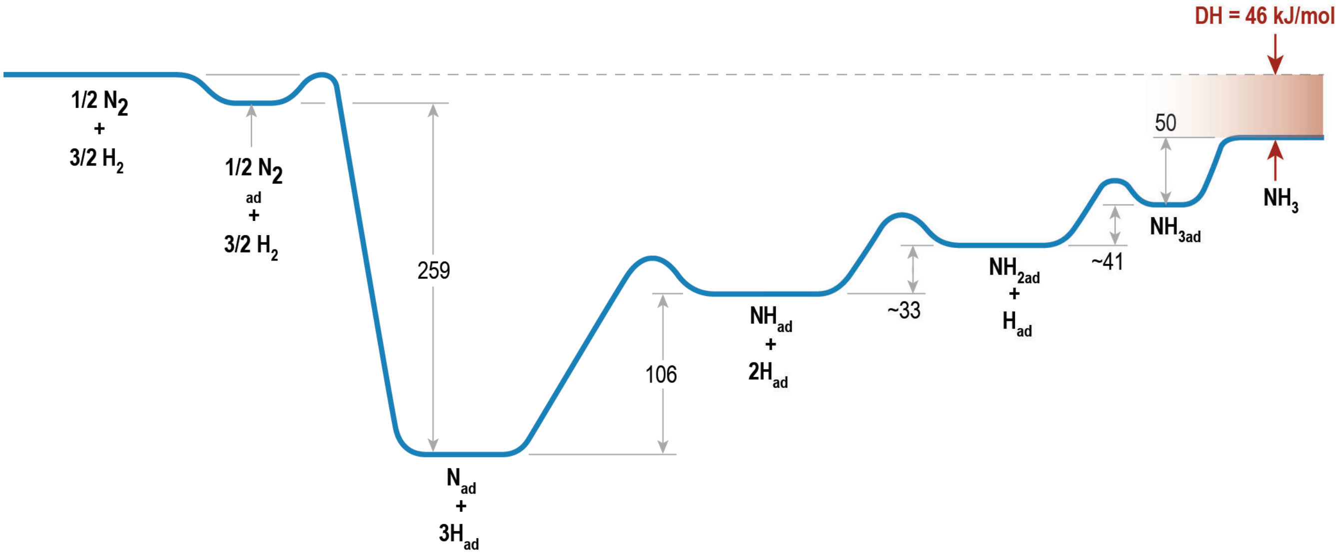

Figure 3C-4. *Schematic Gibbs free-energy chart showing all process steps in ammonia synthesis. Although the reaction is exothermic and theoretically yields energy, thermodynamic losses require additional energy input. Source:*[13]

conversion requires more hydrogen than CO. Commonly, the reaction produces additional hydrogen, which can be sold or used inside the facility for heat or power. Methanol synthesis is insensitive to the source of the primary chemicals, which could be derived from captured CO_2, biofuels, green hydrogen or others.

There are many alternative production methods for methanol synthesis,[18] including biomass-derived syngas and heat,[19] direct electrolytic production, waste conversion[20] and synthesis from recycled CO_2, and green hydrogen.[21] The George Olah plant in Iceland[d] uses this last methodology. In some cases, no process heat is required; although, for the electrical pathways, substantial amounts of additional energy are required.[22,23] Also, unlike ammonia, which burns without returning carbon to the atmosphere, methanol use ultimately returns the chemical-embodied carbon to the air and oceans. If recycled CO_2 is not provided by low-carbon biomass or CO_2 captured from the air, it will add CO_2 to the air and oceans.

In contrast to many of the other sectors and approaches discussed in this report, methanol synthesis and distillation operate at fairly low temperatures (~300 °C). Small burners and furnaces commonly provide heat, which hypothetically could be replaced with hydrogen burners, electrical heating or steam produced by any carbon-free heat, including conventional nuclear reactors. Because of the wide range of potential pathways to generate heat, methanol facilities could serve as a potentially important testing ground for alternative heat supply substitution.

Decarbonization pathways for chemicals and related heat

Several potential pathways exist that could meaningfully contribute to deep reduction in chemical CO_2 emissions. These include demand destruction, material substitution, electrification, carbon capture and storage (CCS) and fuel switching. Estimates for potential size and pace of contribution to decarbonization are highly controversial and sometimes involve full facility

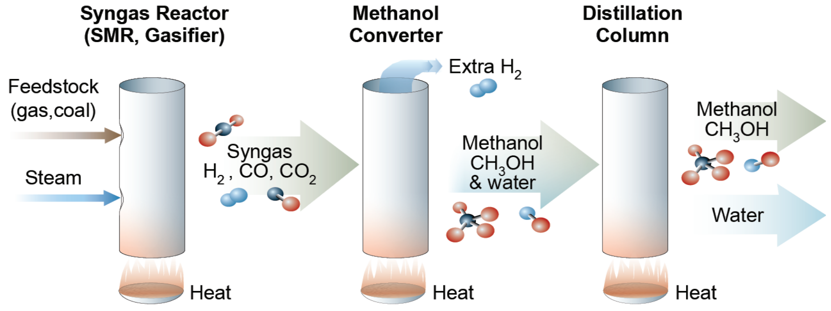

Figure 3C-5. *Schematic cartoon of a methanol synthesis plant.*

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[d] See https://www.carbonrecycling.is/george-olah

replacement or changes in commercial practices and consumer preferences. As before, this discussion focuses on low-carbon fuel substitution for heat and retrofits to existing facilities.

Short-term decarbonization options involve gaseous substitutes

The most common heat source for chemicals is natural gas. Most facilities are situated near major natural gas hubs (current or historical), and supply chains provide natural gas both as a feedstock and for heat. This means that the simplest pathways to substitute low-carbon heat systems are with low-carbon gas supplies.

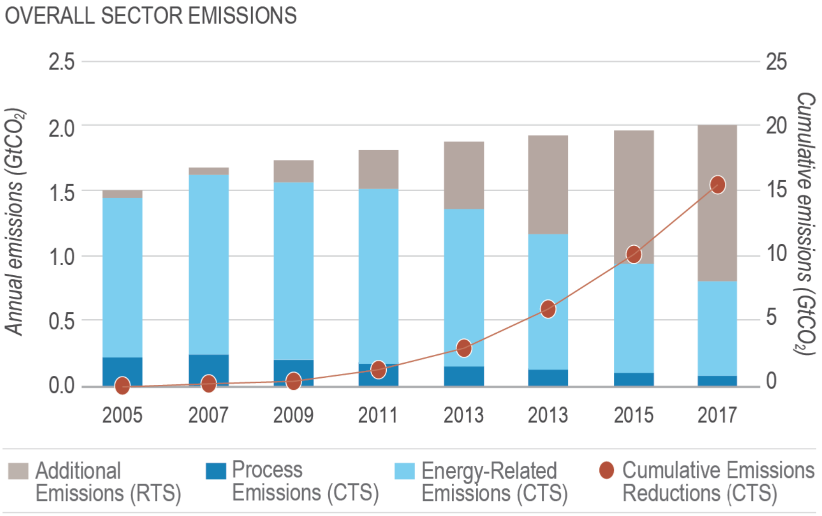

Figure 3C-6. *Scenario-based direct CO_2 emissions reductions in both process- and energy-related emissions for the chemical sector. Source: IEA.*[11]

For these reasons, biomethane is the simplest option, as it can immediately substitute into existing plants with near-zero modification of the system (e.g., [24],[25]). For this to yield low-carbon heat, the life-cycle footprint of the biomethane must be low, whether supplied by gasification, landfill or digester. It is not clear if this is likely to prove competitive in chemicals—the IEA Clean Transition scenario for chemicals found limited uptake of biofuels and biomass substation.[12]

Hydrogen, blue or green, is also a viable option and is the most straightforward to assess in terms of life-cycle analysis (LCA). The temperature of hydrogen burned in air is more than sufficient for all chemical and refining processes. Most systems can accommodate 7-20% hydrogen blends based on the specifics of facility engineering, and indeed some chemical plants already use byproduct hydrogen (e.g., from ethylene synthesis) to produce heat. All of the challenges discussed in the hydrogen section (e.g., embrittlement, corrosion, specific sensors and controls) would apply to such a system.

Medium- to long-term **decarbonization** options involving significant process change

Unlike blue hydrogen or biomethane, other pathways to decarbonizing refining and chemical production are not yet commercial and in many cases are not yet piloted. However, combinations of efficiency, heat substitution and CCS can provide substantial reductions in energy-related emissions—roughly 50% (**Figure 3C-6**). While this set of scenarios finds little decarbonization through commercial application of electrical or biofuel-provided heat, other outcomes are possible given different assumptions.

NOTE: Because many chemical products have embedded carbon (e.g., methanol) which re-enters the air and oceans after use, truly deep decarbonization may ultimately require radically different practice than is used in today's industry. Either all embedded carbon must come from recycled CO_2 (e.g., DAC-supplied or low-carbon-biomass-supplied CO_2; biopolymers) or alternative processes that do not emit their carbon content after use will be required.[26]

A number of alternative processes for ammonia, methanol and other chemicals have been developed or are under development. These involve substantial process changes and generally seek to reduce or eliminate the use of fossil-fuel feedstocks.

One approach is electrosynthesis of feedstocks, including hydrogen and syngas, which can be burned for heat and fuel. Both ammonia and methanol can be converted to electricity through a fuel cell to generate electricity and byproduct N_2 or CO_2. Using a reverse fuel cell, methanol can be generated by adding CO_2 and electricity to a fuel cell in an aqueous environment or the presence of hydrogen. Haldor-Topsoe[27] has designed and piloted this approach, which generates a syngas of hydrogen and nitrogen which enters a conventional Haber-Bosch reactor. This approach is similar to the JGP process piloted at Fukishima[28] and does not require heat for SMR production or energy for the air separation unit.

The process would still require heat for the ammonia synthesis reactions, which could be supplied through hydrogen or ammonia combustion.

Electrification of heat

Prior sections discussed the potential for electrical methods (e.g., resistance or dielectric heating) to provide thermal energy to industrial processes. In the case of chemicals, some electrification will likely prove straightforward and simple. For example, process steam used for chemical synthesis could be supplied by electrical water heaters with limited capital expenditure. The same is true for some small electrical furnaces. Such systems exist today at 0.5-4 MW ratings and could supply distributed steam and heat. However, there have been no published examples of facilities that have instituted such electrification nor has there been an industry census regarding the extent to which these replacements could occur in a straightforward manner.

For more complex chemical reactors (e.g., ammonia or ethylene synthesis), commercial electrical reactors are not commercially available. Given the dimensions and operational requirements of commercial facilities, it does not appear possible to retrofit existing reactors with electrical heating methods today. In addition, extremely low firm power costs are required to displace other low-carbon heat options like biomass or CCS (see below: costs), and displacement costs may vary as a function of facility age, design and the replacement costs compared to retrofit costs.

Integrating CCS into chemical processes

For many chemical manufacturing processes, CCS can significantly and cost-effectively reduce CO_2 emissions. According to IEA analysis,[3] CCS is the chief option of many expected to contribute to least-cost GHG reduction in the chemical sector, followed by efficiency and the switching of coal to gas. This result is both robust and unsurprising. Many production pathways (ethanol, methanol, ammonia) have large byproduct CO_2 streams. Successful introduction and deployment of CCS in chemicals will require investment and engineering that integrate CO_2 capture into conventional operations of chemical facilities. As elsewhere in this report, we focus on application to existing facilities, as opposed to new processes or integrated designs for new facilities.

Carbon capture, use and storage (CCUS) applied to pure streams of CO_2 already operate today. Four large hydrogen plants, one small ammonia plant, one refinery and one ethanol plant operate today with CCS.[29] All of these plants capture process emissions from pure byproduct streams. However, CCS can also contribute substantially to reducing heat-related emissions. In ammonia production, for example, the primary process emissions come from SMR hydrogen production. If a dedicated hydrogen SMR plant was sufficiently large to produce hydrogen for both ammonia synthesis and reactor heat, it could achieve 85-90% CO_2 emissions reduction by turning the plant "blue"—adding CCS to the SMR facility and using the additional hydrogen for heat. In essence, this could decarbonize both process and

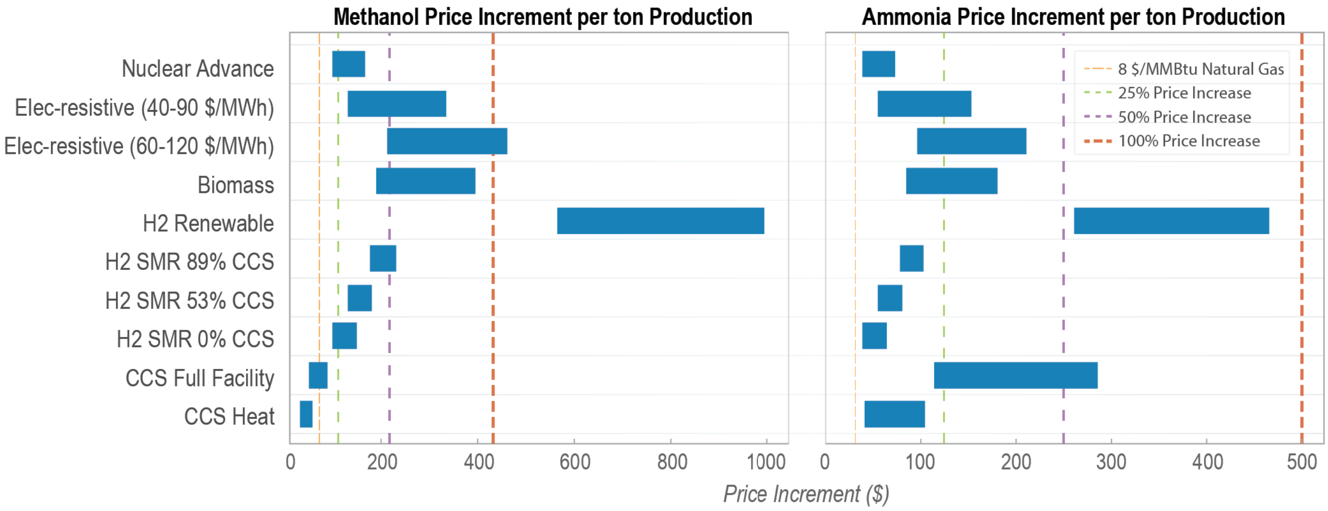

Figure 3C-8. *Cost estimates for different heat decarbonization pathways for ammonia and methanol.*

heat emissions through pre-combustion separation of CO_2 from fuels.

Post-combustion CO_2 separation may be another method capable of reducing emissions at refining and chemical plants. This may prove most attractive for facilities that have large point sources (e.g., catalytic crackers, steam boilers, central furnaces) within their fence lines. In general, post-combustion capture will be more complicated, chiefly due to the range and distribution of CO_2 sources associated with both process emissions and heat. While it may be theoretically possible to retrofit dozens of small sources for capture, it is likely to prove challenging and possibly infeasible.

In either pre- or post-combustion applications, CCS systems will require transportation and storage infrastructure. Many potential facilities for CCS retrofit (pre- or post-combustion) lack pipeline capacity to transport CO_2 and lack ready and available storage sites. Those operating today are largely bespoke contracts for EOR. Although projects have been proposed for CCS clusters and hubs in Europe (e.g., PORTHOS and Teeside),[30] the infrastructure has not yet materialized for lack of investment. For CCS to contribute substantially to decarbonization of the chemicals industry, investment in key infrastructure will prove essential.

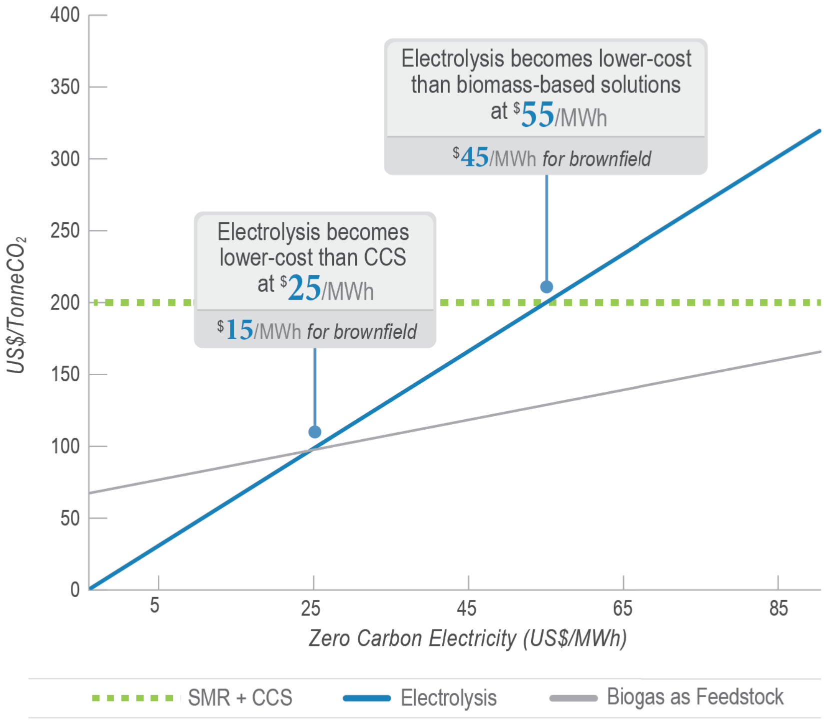

Figure 3C-9. *Estimated abatement costs for greenfield ammonia production as a function of electricity cost compared to biomethane and blue hydrogen (CCS on natural-gas SMR). Source: McKinsey (2018)*[31]

Cost estimates

Estimating costs of decarbonizing heat supplies in the chemicals sector remains difficult. In part, this is due to the range of options and the difficulties in estimating the true carbon footprints of viable options. It is also partly is due to factors that are simply difficult to assess or forecast in the present or future. The estimates discussed here have large ranges and substantial uncertainties. In all cases, however, alternative approaches to decarbonizing heat add substantial cost to unit production.

Using specific assumptions for power price and availability, natural gas price, and other factors, Friedmann et al. (2019) produced estimates for many industrial sectors, including for ammonia and methanol as proxies for the chemical sector (**Figure 3C-8**). For ammonia, they estimate a 5-40% increase in ammonia production costs for most low-carbon heat pathways, with green hydrogen substitution delivering substantially higher unit production costs (60-120% increase). For methanol, they estimate 5-80% increase (with green hydrogen increasing costs 125-190%). In the case of methanol, CCS to heat or to the whole facility appeared to be the lowest cost options.

These estimates are in line with other published estimates. For example, McKinsey (2018)[31] estimated that carbon-free ammonia would increase unit price ~5 to 35 percent depending on the future price of renewable electricity and that power costs would need to range from $25-45/MWh to be competitive with other low-carbon synthesis pathways (**Figure 3C-9**). They considered this economic hurdle to be substantial enough that "decarbonization would require technological breakthroughs, a further lowering of zero-carbon energy prices, changing customer preferences (willingness to pay) and/or a regulatory push." This is similar to the conclusion of Abanades et al.[22] or IEA's

(2013) estimates[32] of additional energy requirements for renewable chemical synthesis (**Figure 3C-10**).[e]

Finally, the Mission Possible report[33] explained the additional required energy to supply only methanol or ammonia as a shipping fuel through electrical synthesis:

> "Total electricity generation, whether for direct use, or for the production of hydrogen, ammonia or synthetic fuels, will need to grow from around 20,000 TWh today to 85-115,000 TWh by mid-century. This hugely increased electricity supply will have to be produced at 85-90% from direct zero-carbon electricity generation (i.e. renewables or nuclear) with only 10-15% coming from biomass or abated fossil fuel inputs."

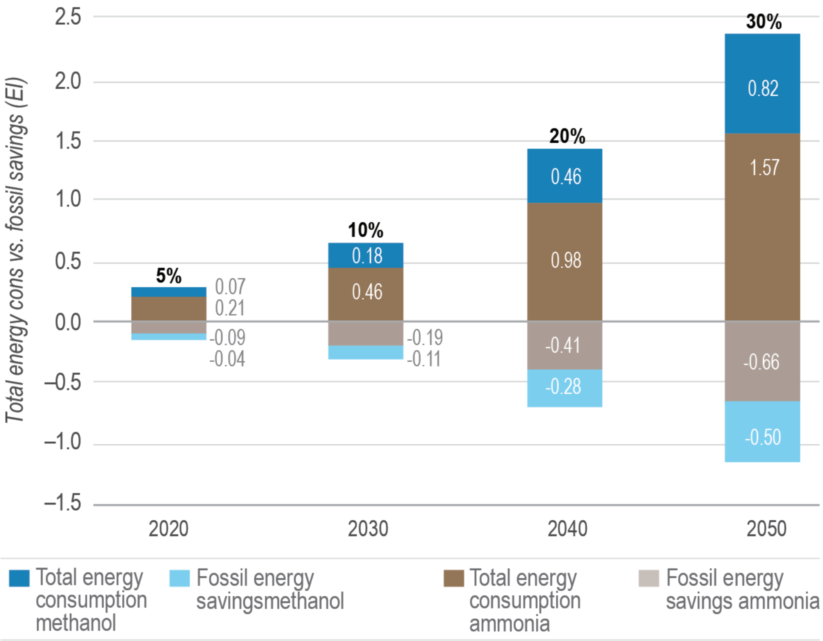

Figure 3C-10. *Additional energy requirements for substitution of renewable power for hydrogen-based chemical synthesis. Percentages represent fractions of total global market. Source: IEA (2013)*[32]

This framework requires system costs for firm zero-carbon power to be between $5-25/MWhr—an extremely low power price—for such fuels to be cost competitive absent policy support. Alternatively, it will be essential to find new and innovative pathways that require much less additional energy or electricity to produce commodity chemicals.

Conclusions: Addressing process heat in chemical manufacturing

- Chemical production, including refining, emits substantial CO_2 from heat—roughly 50% of the emissions from chemical production result from production of heat.
- Almost all heat used in chemical production is provided by natural gas. This suggests that the easiest (near-term) substitution options come from low-carbon gas fuels, including decarbonized hydrogen and biogas.
- Medium- and long-term approaches require much lower costs or more advanced technology to be competitive and scalable.
- Carbon capture and storage (CCS) will likely prove important to decarbonizing chemical production, either in the manufacture and use of "blue hydrogen" or to decarbonize flue gas post-combustion.

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[e] From Katelhon et al.'s analysis of full substitution of electrochemical routes: "If all additional electricity were provided by renewable energy, the amount of renewable energy required for the full-scale introduction of CCU would correspond to 126% and 222% of current targets [sustainable development scenario of IEA (31)] for the global renewable electricity production in 2030 for the low-TRL and the high-TRL scenario, respectively… the need for a further expansion of renewable electricity production capacities is likely to be a limiting factor for CCU in the chemical industry." (https://www.pnas.org/cgi/doi/10.1073/pnas.1821029116)[23]

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CHAPTER 4

INNOVATION PATHWAYS

Innovation in industrial heat is one of the more difficult topics in climate change mitigation, in part due to the large number of processes that must be improved. Industrial heat is deeply embedded in our economy and implemented in diverse processes. It is much less susceptible than electricity or transportation to major changes in the way energy is delivered, rather than how it is used. The use of hybrid approaches, such as carbon capture and storage (CCS) with partial biomass use to improve the overall carbon footprint, may be vital to successful decarbonization of industrial heat.

In addition to the specific options outlined in the previous chapters, four very different innovation pathways appear likely to be broadly useful for a variety of industries:

1. Revising the fuel mix to provide low-carbon- or zero-carbon-footprint fuels without major changes in the industrial process.
2. Improving the way heat is applied in processes, including heat storage.
3. Hybrid approaches, including CCS with process improvements and negative emissions technologies that remove the CO_2 at sites remote from the industrial facility.
4. Cross-cutting systematic changes in hydrogen and biomass supply that address multiple industry sectors.

Delivering zero-carbon fuels via existing infrastructure

Gas

Today's natural gas system powers much of the most efficient industries in the developed world. Most discussions of a completely decarbonized world assume that we stop using natural gas and accordingly abandon that infrastructure. However, in many areas the gas distribution grid is a massive distribution system already in place—for instance, in the Los Angeles area there are 100,000 miles of pipeline feeding residential, commercial and industrial clients.

Currently a small amount of renewable natural gas is being put into the gas systems in Europe and the US. Created mainly from anaerobic digestion of waste, like sewage and agricultural waste, using this gas creates a nearly carbon-free combustion opportunity. Denmark's gas grid has about 50% biomethane content and is projected to be 100% renewable by 2035. This is a very high percentage, reflecting an availability of manure and bioenergy crops that is unlikely to be met in other countries. Recent estimates of the renewable natural gas capacity of California, for instance, place the total at no more than 20% of today's total while using only waste resources (there is no current energy crop contribution to renewable natural gas in California).

As electrification proceeds in homes and commercial facilities, the total amount of natural gas used will drop, making it possible for a higher percentage of the total to be renewable. By adding power-to-gas systems that convert electricity into either hydrogen or methane, nations may be able to provide a large proportion of the industrial need for gas via renewable sources. Current estimates of the allowable percentage of hydrogen in a natural gas system vary widely, depending on issues of corrosion. In 2018, the GRHYD project in France (Gestion des Réseaux par l'injection d'Hydrogène pour Décarboner les énergies [grid management through the injection of hydrogen for energy decarbonization]) began blending 6% hydrogen into the natural gas grid and will test up to 20%.[1] Also, whether hydrogen can be stored in geologic natural gas sites is not known. An R&D effort to determine these limits is needed. A significant limitation on this option is the maintenance cost of the gas grid, which presumably must be shared among fewer users while not changing the more expensive aspects of the system. A transition plan for such a future must be developed.

If hydrogen at high levels is not permissible in existing gas systems, it could be converted into methane by reaction with CO_2. The Sabatier process is in use in a demonstration facility that Audi operates in Germany to make renewable natural gas.[2] An issue with this approach is that it creates heat from the exothermic reaction that must be used if the overall energy balance of the system is to be reduced. Several research groups are also pursuing biological systems to directly convert electricity into methane via microbial populations, led by Germany's Electrochea.[3] They are conducting a small-scale demonstration at the National Renewable Energy Laboratory in the US, with promise for direct conversion of renewable energy into methane. This technology uses hydrogen and CO_2 as the feed for microbes that convert the gases into methane. When using electrochemical generation of hydrogen, the process is about 50% energy efficient at converting electricity into methane. Obviously, this still requires an efficient carbon-free hydrogen source.

Like the Sabatier process, near-term methods of utilizing the existing gas grid involve hydrogen, either directly or as fuel to make other energy carriers, such as methane and ammonia. New means of creating hydrogen are also in development beyond the green and blue hydrogen mentioned earlier. Methane pyrolysis, where hydrogen is stripped from methane at temperatures of 800-1100 °C, is a promising technique that leaves solid carbon as a byproduct or waste to be landfilled.[4] Two methods are currently in consideration. In the older method, methane is bubbled through molten metal, with hydrogen gas and particulate carbon emitted from the top. A newer development by BASF uses a proprietary catalyst in a flow-through system in which hydrogen exits the top and carbon falls out of the bottom of the reactor.[5] Relatively high carbon efficiencies are reported for both systems (above 90%), but the energy demand is substantial, with an estimated efficiency of 55% by Wegen et al.[4] However, as compared to systematic changes in industrial processes, this energy cost could make sense at industrial scale. Detailed system analysis is required.

Hydrogen proponents point out that one of the significant drawbacks to natural gas usage—leakage from pipelines—could be significantly limited by transforming the natural gas to hydrogen near its source and transmitting hydrogen in the pipelines with a much smaller impact on climate if leakage occurs. Combinations with solar thermal—both as a high-temperature-process heat source for the methane pyrolysis and as a heat storage system for combining other renewable energy—are an attractive innovation pathway.

This innovation pathway envisions a mix of gases, renewable natural gas and hydrogen, playing the role that natural gas does today. Other promising technical approaches include low-cost electrolyzers and nuclear H_2 production (e.g., Sulfur-Iodine cycle discussed previously). Hydrogen production may become global as well, with both Australia[6] and the UAE considering large-scale export of hydrogen by refrigerated tanker. France announced its Hydrogen Deployment Plan for Energy Transition in June 2018, the targets of which include 20-40% low-carbon hydrogen use in industrial applications of hydrogen and a reduction in electrolysis cost €2-3/kg by 2028.[1] This innovation pathway will require consideration of the needs for infrastructure to accommodate that scale of import, but since many major industrial facilities are near ports, this could be a dramatic change in world energy markets.

An innovation pathway of major hydrogen production, from zero-carbon natural gas conversion or from renewable energy followed by liquified hydrogen transport over the high seas, could dramatically change the future of industrial heat sources but will require a massive new set of infrastructure for hydrogen generation and transport, while allowing existing industry to keep very similar processes and procedures. In a first-of-its-kind design, Kawasaki Heavy Industries (KHI) in collaboration with Shell, is developing a purpose-built liquefied hydrogen tanker capable of shipping 1250 m^3 (88,500kg) liquid hydrogen (LH_2) from Victoria to Japan in 16 days. According to the New Energy and Industrial Technology Development Organization (NEDO), the carrier is forecast to be ready to make its first shipment in 2020/2021. These sorts of options will significantly increase the costs of gas but may still be dramatically less costly than wholesale revision of industrial processes. An important innovation pathway is to make a detailed comparison of the transition costs to determine if large-scale efforts at rethinking the use of gas for industrial purposes is warranted in a low-carbon future.

Hydrogen requires another set of safety and use approaches if it is to be used in gas pipelines, including material compatibility, flame awareness (hydrogen is invisible when burning) and odorization. Gasket materials need to be evaluated, and geologic storage of hydrogen gas needs to be experimentally demonstrated.

Other biofuels

Biomass provides a commonly used approach to replace fossil fuels. Solid forms like torrefied biomass can be used directly in place of coal. Bio-char, while commonly considered as a soil amendment, could be used instead as a fuel. These options are particularly interesting for the calciner in cement plants, which are renowned for their ability to burn almost any fuel. Bio-oil is created by fast pyrolysis of biomass and can also be used as a liquid fuel in many systems that use heating oil today, although some hydrogenation is required to stabilize the bio-oil.

These options suffer from the same availability issues as renewable natural gas. In most integrated assessment model evaluations, there is insufficient biomass to meet all the competing needs in a decarbonized world. A major innovation pathway issue is evaluating the comparative costs of transition for using this resource in industry. Because these fuels can be used with only minor process changes, they are attractive for some industrial sectors as a means to decarbonize. The scale is realistic. It takes about 200 kg of coal to create one ton of cement. Replacing that coal with torrefied biomass—notwithstanding constraints on fuel heating value in the kiln—would require about 2-3 times as much original dry biomass. In California, that would require about 4-5 million tons of biomass to fuel the state's cement production. Recent estimates indicate that about 70 million tons of dried biomass could be obtained from waste sources in California.[7] Using torrefied biomass to eliminate the energy emissions (but not the calcining emissions) would reduce CO_2 emissions from cement production by about 50%. Thus, biomass for replacement of coal industrial heat, particularly in cement production, which is relatively tolerant of fuel quality, is an innovation pathway that can be considered along with the use of biomass to produce liquid fuels.

The major innovation needs in this area are to develop efficient means of converting biomass to transportable forms without more carbon emissions—for instance, torrefaction is often done today with external natural gas heating. Autopyrolysis systems that use the biomass itself to provide heat would avoid those emissions.

A major innovation issue is the extent to which nations may choose to become biomass exporters to provide industrial heat sources. The operations at the Drax power station in England have demonstrated that a large-scale, long-distance biomass supply chain can be created and sustained—although the carbon emissions from this supply chain may be substantial. As with hydrogen, new infrastructure pathways could make delivery of biomass as an industrial heat source a global commodity.

Of great interest in this area is the possibility of combining biomass heat sources with CCS, yielding a portion of negative emissions. In this scheme a cement kiln could relatively easily operate the calciner on biomass fuel, while capturing and sequestering some fraction of its total CO_2 emissions and thereby offsetting all of its emissions. For many industrial processes, partial capture on existing equipment is much more practical than 100% capture.

Innovation Agenda for Zero-Carbon Fuels

Innovation pathways for zero-carbon fuels focus on production of the fuels, systematic transport and distribution issues associated with large scale replacement of natural gas by renewable gases, and more focused replacement of coal by biomass.

- Evaluation of the cost benefits and life cycle of the replacement strategies
- Evaluation of transportation and distribution methods and costs
- Development of safety and use schemes
- Improved production schemes and assured zero-carbon technologies
- Evaluation of materials for transport and storage of hydrogen, including odorants and flame visualization.
- Evaluation of the timing and staging of adding fractional amounts of zero-carbon fuels to industrial systems.

Improved heat application

Electrification

Use of electricity to provide heat in industrial processes requires massive changes in industrial equipment as discussed in Chapter 2C. Three major issues arise:

1. There has been little R&D on massive electrification options.
2. Transfer of heat in systems such as blast furnaces is a function of the physical dimension of the coke, which supplies support as well as heat.
3. Electrification can rarely be done in the context of existing equipment.

Dealing with the second issue is particularly difficult. The highly tuned nature of the chemical reactions and heat transfer in a system like a blast furnace makes it unlikely to be decarbonized by either electricity or biomass; the most likely approach is CCS (below) or change to completely different processes where the chemical-reducing potential of either hydrogen or biomass can be utilized.

The third issue in the list above is more amenable to an innovation pathway, as discussed in the electrification chapter. The application method for electricity to industrial processes can be changed dramatically by using direct microwave or inductive heating to deposit energy. Each industrial process requires R&D to identify the most efficient electrical energy deposition method, and there is relatively little room for generic development. Each industry must be considered and the choice of new electrical heating method evaluated. This requires very different approaches than for revisions to the gas grid, since every industrial process will require slightly different innovation pathways.

Improved electrification pathways have had extremely little research attention. Basic understanding of how heat is deposited in material, skin depths for dielectric heating, changes in resistance with chemical changes, and safety issues have been evaluated at small scale but rarely at the size of industrial processes. National-level programs addressing key industries are required to fill this gap.

Solar and stored heat

Many research teams are focused on solar thermal applications to industrial processes. With focusing mirror systems that can readily exceed 1,000 °C, this is academically attractive but requires appropriate heat transfer mechanisms to move the heat from the mirror system to the industrial process. Typically, industrial processes at this temperature use direct combustion heating, so there is no existing art around the movement of heat at these temperatures. However, the demonstrated ability to store heat in solar-thermal electricity generation makes that option interesting to industry.

Reducing or eliminating heat in processing

An obvious efficiency pathway is to develop catalysts that replace heat as a means of speeding chemical processes. Particularly in the chemical industry, heat has been the method of choice for speed. Innovation in catalysis will be valuable there. A major innovation would be the replacement of thermochemical production systems with electrochemical methods, particularly those that begin with CO_2. A growing literature (e.g.,[8,9]) indicates that this is possible, but currently will use an enormous amount of electricity. Innovation around more efficient electrochemical processes, particularly reduction in overvoltage and resistance losses, is needed.

Innovation agenda for improved heat application

Innovation pathways for electrification focus on the determination of the most cost-effective approaches.

- Evaluation of the most appropriate electric energy deposition methods by industry.
- Improving combustion systems, burners and combustors.
- Evaluation of the comparative capital costs of reconfiguring each industrial process, which will be very substantial and must be weighed against CCS or zero-carbon fuel options. Among the key industrial processes which will have significantly specialized electrification methods are:
    4. Calcining
    5. Refining
    6. Distillation
    7. Glass production
    8. Removing impurities from metals
    9. Ceramics production
    10. Drying
- Development of more efficient high-temperature heat storage.
- Development of new electrochemical methods that require much less electricity than today's incipient methods.
- The innovation need for solar and stored heat is around better heat transfer systems and fluids for moving heat at those high temperatures.
- The innovation agenda for reduced heat focuses on new electrochemical methods that require much less electricity than today's incipient methods.

Carbon capture and storage (CCS) and hybrid approaches

Carbon capture and storage

CCS has not been extensively applied to industry. In Chapter 2D we outlined the major opportunities, which are focused on R&D to demonstrated specific CCS methods for industry. The major challenges are multiple small emitters in single facilities like refineries and the need for specific process designs for each industry type. A substantial demonstration program is required to reduce the technology risk for each industry's CCS approach.

Application of CCS to industry will also require the collection and geologic storage systems that electric power systems need. This is an opportunity for national carbon management programs to consider infrastructure needs like pipelines, but these needs are not specific to industrial application of CCS.

Oxygen-fired systems are a likely component of decarbonized industrial heat. The production and transportation of oxygen for these systems is a significant challenge, also not unique to this report, but of a similar scale to the production of hydrogen in terms of impact and complexity.

Hybrid approaches

Throughout this report we have highlighted the difficulty of decarbonizing industrial heat due to the great variety of systems that must be decarbonized and the limited number of options for performing that task. Our discussion has focused on individual solutions—hydrogen, electrification, biofuels, etc.—but hybrid approaches may also be very useful. These include partial fuel decarbonization, partial changes and electrification of the production environment, and partial addition of CCS to particularly susceptible parts of the production scheme that continue to use fossil fuels because of their particular suitability. These solutions may start as partial decarbonization that is highly cost effective and evolve into full decarbonization as multiple approaches are applied. For instance, improved burner technology may be incorporated as partial hydrogen or renewable gas become available, or electrification of small-scale heat sources may occur inside refineries while larger units like steam methane reformers depend upon CCS.

Hybrid approaches may be particularly useful in combining CCS on existing equipment, with partial biofuel substitution on that existing equipment. Because of the carbon neutral nature of the biofuel, doing partial carbon capture can offset the emitted fossil-fuel component, resulting in net zero emissions. Such schemes with a biomass component have many flavors, including gasification of biomass to hydrogen, capturing and storing CO_2 before it reaches the industrial facility. Bioenergy with CCS (BECCS) is a likely component of hybrid systems.

Timing issues will be important for hybrid systems. For instance, 10% substitution of hydrogen is straightforward in most burner systems, but higher amounts eventually require new burners and new delivery materials. Similarly, the other uses of a gas grid need to be considered—will industry share transition costs with home and business gas use, or will those be electrified independently?

The final novel hybrid pathway is to use negative emissions—primarily direct air capture—to offset industrial emissions. At some level it is extremely likely that this will be needed, as it is clear that complete decarbonization of industrial heat is difficult. Today costs for direct air capture systems are approximately \$600/ton CO_2. It is widely expected[10] that these costs can be reduced to the vicinity of \$200/ton, and the developers believe that \$100 can be obtained. For an industrial facility operating on existing equipment with 90% capture, it may be cost-effective to capture the remaining 10% of the emissions at a large air-capture facility shared with other facilities.

Innovation agenda for CCS and hybrid approaches

CCS needs specific design studies for application to industrial streams. The opportunity for hybrid approaches in this area is large, requiring the development of robust cost and life-cycle models to estimate the costs of combined approaches, including those that use shared facilities. Another innovation pathway is to consider if there are options to combine direct air capture, which is very dependent on heat, with industrial waste heat sources.[11] While the first priority should always be to reduce waste heat to the greatest extent possible, where this waste heat is of a low quality and not economically feasible to recover, it could be used for solid-sorbent-based processes (e.g., in combination with heat pumps). This could be particularly useful to deal with emissions from the "use phase" of products that are not amenable to CCS. The innovation agenda is to consider the capital and operating cost cross-over point where direct air capture becomes the more effective way to achieve additional decarbonization and whether large-scale systems could be utilized to polish the emissions of entire industrial sectors.

	Near term		Mid term		Long term	
Zero Carbon Fuels	Evaluate cost benefits and transport costs	Research power-to-gas (H_2 and CH_4) technologies	Develop safety methods for H_2	Determine pipeline H_2 limits	Improve renewable natural gas & H_2 production methods	Improve H_2 materials for transport and safety
Improved Heat Application	Evaluate electricity deposition methods	Evaluate costs of reconfiguring processes	Improve existing combustion systems		Develop more efficient heat storage and transport	
Hybrid	Design CCS for specific industries	Evaluate cost and lifecycle for hybrid processes	Evaluate costs of off-site carbon management	Test hybrid biomass/capture systems		
Cross-Cutting	Evaluate costs and impacts of large-scale hydrogen transport	Evaluate costs and impacts of large-scale biomass transport	Determine where to commit existing biomass resources	Demonstrate large-scale hydrogen shipping	Develop biomass systems that are carbon-negative across the life-cycle	Develop large-scale hydrogen production and transport

Table 4-1. *Major Innovation Pathways*

Cross-cutting issues: system innovation and transportation pathways for biomass and hydrogen

As we move toward a decarbonized industrial system, society will have to make choices in two major areas: how to use available biomass, and whether to use renewable power to create gas that can be distributed in existing networks.

As we saw in the biomass chapter, it is possible to imagine powering a substantial portion of tomorrow's industry with biomass, but that use would be in competition with liquid fuels, pure negative emissions and, of course, the uses for biomass today, including cooking and heating. Most authors today prefer to consider only the amount of biomass that would be available from waste and supplies of biomass that do not place pressures on the availability of food or ecosystem services. That amount of biomass is therefore limited but extremely valuable from a climate perspective.

Today there is no clear metric to decide where to commit our biomass resources—creating such a metric is a major innovation pathway. International agreement will be important, since the Drax experiment in the UK has demonstrated that large-scale biomass shipping is feasible, even if it does not achieve the desired economic and climate impact.

Power-to-gas is a second pathway that requires cross-cutting development and agreement. Will we attempt to repower industry with a zero-carbon gas system? What methods would be used to create the hydrogen or renewable natural gas? Today there is no clear economic pathway to evaluate this option, mainly because attention has been focused on the electric power sector. As renewables become cheaper, use of hydrogen and renewable natural gas is less attractive for electricity generation but may still be of primary importance for industry. However, a reduced gas grid for industry use still needs to be maintained at a considerable cost. A clear understanding of what it would take to create a zero-carbon gas system is necessary to make it possible to consider this option.

And just as ocean-shipping of liquid natural gas (LNG) rapidly changed the energy world, worldwide shipping of biomass and hydrogen could have a similar effect for industry. Nations and regions could choose to commit resources to large-scale production of these heat sources and send them by ship to industrialized regions. The offsetting effects of investing in new infrastructure to ship these products and of maintaining expensive industrial facilities with minimal changes could make that an economic- and climate-appropriate solution for many forms of industrial heat. The time to evaluate the possible impacts of such choices is now, before massive investments are made.

These innovation pathways are combinations of applied and basic research, reflecting the deep need for new processes and approaches in industry. Past roadmaps have called out separate innovation agendas for these topics, but the need for broad changes suggests a great number of basic and applied topics. We must move further down the innovation pathways before there are clearly defined needs in specific areas.

Analysis and modeling are key elements of all these innovation pathways and are more important in the hybrid and new-fuel scenarios such as shipping large amounts of biofuel long distances. Indices of success are needed, and tools to compare options across broad swaths of industry must be developed. This need for comparative and planning tools is the foundational element of all the innovation pathways described here, as is the need for broadly applicable data about heat use in industry. Without these, innovation cannot proceed in the most efficient and diverse ways.

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CHAPTER 5

POLICY

Policy tools are essential for decarbonizing industrial heat, both in the short- and long-term. This chapter discusses the rationale for policy support and range of policy tools available.

Rationale

The concentration of carbon dioxide (CO_2) in the atmosphere is higher than at any time in human history. Human activities, including fossil fuel combustion and deforestation, continue to increase that concentration. The impacts include heat waves, more severe and frequent storms, sea-level rise, forest loss, and ocean acidification.[1]

These problems are classic "externalities." Market forces alone will not control CO_2 emissions adequately, since emitters of CO_2 do not bear the full costs of their emissions. Government policies are essential.[2,3]

Reflecting this, more than 175 countries have ratified the Paris Agreement, which requires each of them to regularly report on their policies for controlling emissions of CO_2 and other heat-trapping gases. The Paris Agreement calls for "holding the increase in the global average temperature to well below 2 °C (3.6 °F) above pre-industrial levels," "pursuing efforts to limit the temperature increase to 1.5 °C (2.7 °F) above pre-industrial levels" and achieving net zero emissions in the second half of this century.[4]

Decarbonizing industrial heat is an important part of any strategy for meeting those goals. As noted in previous chapters, roughly 10% of global CO_2 emissions come from production of industrial heat—more than emissions from cars and planes.[5,6,7] Achieving the goals set forth in the Paris Agreement would be difficult if not impossible without cutting emissions from industrial heat production.

This will present significant challenges. Several industries with high CO_2 emissions from heat production (including iron, steel and some chemicals) are strategically important to host governments and exposed to competition from foreign trade. Some of these industries provide considerable employment. For these reasons and others, many governments will be reluctant to impose policies that disadvantage domestic companies in these industries in international trade or might lead companies to shift production abroad. This will constrain the set of politically acceptable policy responses in many cases.

Many policy tools are available to help with decarbonizing industrial heat. These are discussed below.

Policy tools

Government support for R&D

National governments spend roughly $15 billion annually on R&D for clean energy technologies. These programs have played important roles in the development of countless technologies in recent decades.[8]

Several recent government R&D programs have targeted innovations in industrial heat. These include:

1. A US Department of Energy (DOE) ARPA-E program on novel heat-exchanger technologies.[9,10]
2. A French National Center for Scientific Research program on high-temperature solar-heated reactors for industrial production of reactive particulates.[11]
3. A European Commission program on integration of solar heat in industrial processes of the agro-food industry.[12] Increased funding for R&D on decarbonizing industrial heat could speed deployment and yield important benefits. This roadmap identifies a number of priority areas for R&D investment. (See Chapter 4 above.)

In December 2015, heads of state from more than 20 countries announced Mission Innovation, a coalition dedicated to accelerating clean energy innovation. Member governments (including Japan, China, the United Kingdom, Germany and Saudi Arabia) pledged to double R&D on clean energy within five years. The increase in R&D budgets from these countries in the years ahead offers an opportunity to increase government R&D funding for decarbonization of industrial heat, including in the areas above.

The US helped launch Mission Innovation and remains a member. Although the US is unlikely to fulfill its overall doubling pledge under the Trump administration, the US Congress has increased funding for energy efficiency and renewable energy programs at the US DOE in each of the past several years.[13]

Government Procurement

In many countries, government procurement makes up more than 10% of GDP.[14] Government purchases can play an important role in starting and building new product markets. First, government purchase contracts can provide developers and manufacturers of new products with an assured market, which can be especially important in securing debt capital. Second, government purchases can help establish standard technical specifications for new products, which can help catalyze efficient supply chains.

Governments are major purchasers of steel, cement, chemicals and other products that require heat in the manufacturing process. Procurement standards that give preferences to products with the lowest embedded carbon content could drive significant changes in industrial behavior. Procurement standards that authorize purchasing officials to base decisions on lifecycle carbon emissions of products could do the same. California's Buy Clean statute is a leading example of legislation that directs authorities to pay attention to climate impacts in the procurement process. Similarly, procurement regulations could give preferences to products manufactured without the use of fossil fuels to generate heat.

Fiscal subsidies

Decarbonizing industrial heat will impose costs on affected businesses. Capital expenditures may be required to retrofit facilities or build new facilities. The cost of physical assets may need to be written off if those assets are retired before the end of their useful lives. Operating expenses may increase if inputs are more expensive than current fossil fuel inputs.

Government policies can help to reduce those costs with fiscal subsidies. These can take several forms. Leading options are discussed below.

A. **Tax Incentives.** Tax incentives can play an important role in spurring deployment of clean energy products. In Norway, for example, generous tax incentives helped plug-in electric vehicles capture 50% of new car sales in 2018.15 In the US, federal tax incentives have played an important role in promoting deployment of solar and wind power. Such incentives could play a similar role in promoting alternatives to the use of fossil fuels in industrial heat production. There are many possible structures for such tax incentives. They include:
   - **Investment tax credits:** Governments could provide businesses a tax credit for a percentage of the capital costs incurred in transitioning to low-carbon industrial heat. (This would be similar to the US federal government's investment tax credit for solar power, which has historically provided a tax credit of 30% of the cost of any solar installation in the US.)
   - **Production tax credits:** Governments could provide a tax credit for any products manufactured using low-carbon industrial heat. (This would be somewhat similar the US federal government's production credit for wind power, which provides a tax credit based on the kWh of wind power sold at a facility.)
   - **Waiver of sales, value-added taxes or import taxes:** Governments could waive taxes that would otherwise be imposed on any products manufactured using low-carbon heat. (This would be similar to Norway's incentives for electric vehicles, which include waivers of import and sales taxes that apply to conventional vehicles.)

B. **Grants.** Grants are among the most direct ways to provide financial support for the low-carbon transition. Grant programs are widespread in many countries, often to assist in deployment of first-of-a-kind or early-stage technologies. Governments could provide grants to help defray the capital costs associated with the transition to decarbonizing industrial heat processes.

C. **Loan guarantees.** Cutting the cost of debt capital can help make a project financially viable. Government loan-guarantee programs seek to do that by reducing risk to lenders, resulting in lower borrowing costs. The US DOE's loan-guarantee programs helped launch the utility-scale solar industry in the US, among other successes. Loan guarantees for the capital expenditures required for decarbonizing industrial heat could significantly speed deployment.

D. **Feed-in tariff for renewable natural gas.** A feed-in-tariff provides a guaranteed price for an energy product for a set number of years. This can dramatically improve bankability of projects and help to scale up production. Feed-in-tariffs have been used to help launch markets for solar power and other renewables around the world. Germany and the Netherlands have implemented feed-in tariffs for biogas. This is an important tool for helping promote production and use of renewable natural gas.

E. **Contracts for Differences.** Contracts for Differences are used in the United Kingdom to support low-carbon electricity generation. In a Contract for Differences, the government guarantees a power supplier will receive a stated amount, covering the difference between that amount and the amount the power supplier actually receives. This policy could be used to help support deployment of low-carbon heat technologies as well.[16]

Low-carbon product standards

A low-carbon product standard sets a limit on the product's life cycle emissions. Low-carbon fuel standards—the leading example of such an approach—have been adopted in California, Oregon, British Columbia and the European Union. California's low-carbon fuel standard requires producers of petroleum-based fuels to reduce the carbon intensity of their fuels 10% from 2010 levels by 2020. The EU's Fuel Quality Directive requires reductions of 6% in the carbon intensity of fuels from 2010 levels by 2020.

Such standards could be applied to a range of products currently manufactured using fossil fuels to generate heat. The administrative complexities associated with such a program could be considerable, in part because many of the most relevant products are inputs into other products. However low-carbon product standards could provide considerable incentive for manufacturers to find alternative ways of generating such heat.

Infrastructure development

The transition to low-carbon industrial heat may require new infrastructure (such as electric transmission lines or hydrogen pipelines). Governments can play a central role facilitating the development of such infrastructure through permitting, financing and other measures. Governments can also take a direct role through development and ownership of such infrastructure where it serves a common good—as is often the case for road, rail, district heating and water infrastructure.

Carbon prices

A price on carbon dioxide emissions, whether through an emissions trading program or tax mechanism, provides emitters with an important incentive to cut emissions. Carbon pricing enjoys overwhelming support among academic economists as the most cost-effective approach for addressing climate change.[17]

Carbon pricing continues to grow steadily around the world. Fifty-seven jurisdictions covering 20% of global greenhouse gas (GHG) emissions now have carbon pricing initiatives that have been implemented or are scheduled for implementation.[18,19]

Unfortunately the results of those programs are not encouraging in several respects. First, very few carbon-pricing programs have resulted in carbon prices sufficient to significantly reduce emissions. Governments have generally been unwilling to impose such prices, often due to strong opposition from the businesses and individuals most exposed to energy price increases. Second, programs in several jurisdictions (including those in Australia and several US states) have been suspended or terminated due to changes in political leadership.

The carbon prices that might be needed to induce a transition from fossil fuels for industrial heat production are unclear. These levels likely vary considerably from industry to industry and even facility to facility. In the absence of readily available substitute processes for generating heat, the carbon prices required to induce a transition from fossil fuels would likely be quite high. Few if any countries have demonstrated a willingness to set carbon prices at these levels.

Nevertheless, a growing number of businesses use "shadow carbon prices" when making long-term capital investment decisions. (That is, the businesses apply a carbon price in calculating returns on capital, even if no carbon price or a lower carbon price is imposed in the jurisdiction in which they operate.) These shadow carbon prices may play an important role in affecting capital investment decisions on the margin. The adoption of mandatory carbon pricing programs in jurisdictions around the world, even with carbon prices at modest levels, may encourage business use of shadow carbon prices.

Carbon tariffs

In 2017, 440 million tons of steel was traded internationally. This was more than a quarter of global production.[20] Other products that require heat in the manufacturing process—including some chemicals—are traded internationally in high volumes as well. Many governments may be reluctant to impose costs related to decarbonizing industrial heat on the manufacture of such products, due to concerns about disadvantaging such products in international trade.

Carbon tariffs (sometimes called “carbon border tax adjustments”) are a tool for addressing that concern. A country that requires its manufacturers to transition to low-carbon industrial heat could tax imports of relevant products from countries that fail to do so. This could level the playing field, eliminating the disadvantage domestic manufacturers face from higher costs associated with decarbonizing their heating processes.

No carbon tariffs have ever been adopted. There at least three practical concerns with carbon tariffs:

- Such tariffs may not be legal under the rules of the World Trade Organization (WTO). As a general rule, the WTO prohibits restrictions on the import of goods based on anything other than attributes of goods at the border. (Countries are not allowed to discriminate between goods based on characteristics of upstream manufacturing processes.) There are exceptions, including some that might apply to carbon tariffs (such as an exception related to environmental protection). In recent years the permissibility of carbon tariffs under the WTO has been debated extensively by leading trade experts. The issue has not been resolved by a WTO tribunal.[21-24]
- Challenging design and administrative questions must be addressed to implement a carbon tariff program. Decisions must be made about which products are subject to the tariffs. (For example: Would steel from a zero-emissions steel plant located in a country without carbon emissions limits be subject to the tariff?) Decisions must also be made about how to set carbon tariff levels. Depending on those decisions, extensive data collection and processing could be required to effectively administer the tariffs.
- Although carbon tariffs could in theory level the playing field for manufacturers in their home markets, they do nothing to help manufacturers selling abroad. A manufacturer that incurred additional costs to decarbonize industrial heat processes would still be at a cost disadvantage in foreign markets. Other tools, such as cost rebates for exports, would be required to ensure level playing fields abroad.

Mandates

Governments mandates can be effective in helping build markets for clean energy products. In the US, many state governments require utilities to purchase a minimum percentage of their power from renewable sources. In India, a similar requirement is imposed by the Ministry of New and Renewable Energy. These requirements have been important to the early growth of wind and solar power in both countries.[25]

Other experiences suggest caution, however. The US federal government mandate has required the use of cellulosic ethanol in fuel supplies for almost a decade. Nevertheless, the cellulosic ethanol industry remains in its infancy and waivers to that requirement have been granted on a regular basis. Technology-forcing requirements—in which governments require private actors to meet standards that are not yet technically achievable—have been successful in some instances but not in others.[26]

Government mandates could help spur the transition to low-carbon industrial heat. Governments could prohibit the use of fossil fuels in generating heat in certain industrial sectors after a certain date, for example. Or governments could require the use of low-carbon industrial heat technologies after a certain date. Business investment in compliance strategies with such mandates could help to spur innovation.

Voluntary industry associations

Industry associations such as World Steel Association, World Petroleum Council, World Cement Association and World Business Council on Sustainable Development can help develop methods and standards for decarbonizing industries. They can play an important role in information-sharing on such topics as well. Governments can encourage such activities by hosting meetings, providing recognition and offering financial support.

Clean Energy Ministerial

The Clean Energy Ministerial is a global forum where major economies work together to share best practices and promote policies and programs that encourage and facilitate the transition to a global clean energy economy. A Clean Energy Ministerial initiative on industrial heat decarbonization could help to share best practices and accelerate their adoption. Any country that participates in the Clean Energy Ministerial could launch such an initiative.

Decarbonization of industrial heat is unlikely to happen at scale as a result of voluntary measures. Policy supports will be required for this transition. The diversity of industries in which supports are needed complicates policy design and implementation. More research, analysis and consultation with key stakeholders are needed to shape the best policies to help meet this challenge.

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CHAPTER 6

FINDINGS AND RECOMMENDATIONS

Decarbonizing industrial heat production will require innovating in multiple sectors. Progress will require a set of actions grounded in improved knowledge, strong analytical foundations and support from key stakeholders. In this chapter, we summarize our key findings and recommendations.

Findings

Finding 1: *Emissions from industrial heat production limit progress on climate goals.* Roughly 22% of greenhouse gas (GHG) emissions come from industry, and roughly 40% of those emissions are the result of burning fuel to generate heat. This places heat-related industrial emissions close to 10% of total global GHG emissions—more than cars and planes combined. Deep decarbonization will be difficult or impossible without progress in decarbonizing industrial heat sources.

Finding 2: *The operational requirements and commercial realities of many industries limit opportunities for decarbonization.* The industrial sector is actually many different sectors with distinct products, markets, technologies and operational requirements. Many industrial processes require temperatures above 300 °C and some above 1,000 °C. The narrow margins of the business and high-capital expense of industrial facilities frequently require high-capacity factors for profitability. Many industrial products are globally traded commodities that are extremely sensitive to price. Many are strategic industries whose economic viability is of considerable importance to host nations.

Finding 3: *There are few options today for low-carbon heat generation for industry.* High-temperature requirements and high-capacity factors limit the options for substitution of fossil fuel heat with low-carbon alternatives. For new facilities and especially for existing facilities, commercially available options today face enormous challenges based on both cost and performance. Many industrial processes are highly integrated, making it difficult to pursue simple fuel substitution without a larger system redesign. Biofuel and hydrogen combustion may be the most promising options for the highest temperature applications. (Although electrical heating pathways can generate high temperatures, they would require very large capital investments in many industries.) CCUS applied to hydrogen production or combustion facilities remains an option and has the benefit of also managing byproduct process emissions, but sector-specific analyses to date are limited. More broadly, there is a lack of analysis on the costs, benefits and tradeoffs between alternative options.

Finding 4: *Existing options face challenges based on price, performance and viability.* Fossil fuels provide the overwhelming majority of industrial heat today. Preliminary analysis suggests that all possible alternatives carry substantially higher costs, typically 50-500% more, and may have even higher system costs (e.g., due to additional infrastructure requirements). In some cases, the carbon reductions associated with an alternative are unclear (i.e., grid-based electricity or biofuels). Questions remain about the ability of some options to scale. Many of those options do not provide sufficiently high temperatures for some applications. In many cases, it is unclear if a particular approach represents a viable alternative at all, as it is unclear how it might be used to deposit heat where needed in specific applications.

Finding 5: *There appear to be many pathways to improving cost, performance and viability of low-carbon industrial heat options.* Despite the challenges alternatives face today, most approaches could be dramatically improved. Although the precise magnitude of potential cost, performance and life-cycle improvements are unclear, substantial improvements in system engineering, performance, process intensification, heat recovery, capital cost and capacity are possible in most systems. Novel approaches to some industrial processes appear to be able to provide large improvements in cost and life-cycle decarbonization, although most require further exploration and testing before scale-up

Finding 6: *Many potential policy options exist that could improve the speed and magnitude of industrial decarbonization and deployment of low-carbon alternative heat systems.* Government procurement may be an especially potent policy tool. Governments are major purchasers of cement, iron and steel, and other industrial products. Procurement rules that give priority to products produced in low-carbon processes could spur innovation and deployment. Investments in R&D through tax incentives or grants could also have a significant payoff. In contrast, economy-wide carbon taxes may have limited impact on GHG emissions from industrial heat production. In part, this is due to the exposure of many industries to competition from global trade. All options would benefit from additional analysis.

Recommendations

- **Recommendation 1:** *Key stakeholders should prioritize industrial heat production as a key element of any climate mitigation strategy*. Governments, companies and researchers should prioritize characterization and analysis of their industrial sectors. Core data and information, such as capacity factors, fuel purchased and facility-based efficiency, should be gathered and made publicly available.
- **Recommendation 2:** *Industry-specific analytical frameworks and innovation agendas are essential.* Governments and companies together should develop new initiatives and R&D programs to focus on industrial-sector decarbonization with a focus on heat supplies. Governments, academic researchers and industrial leaders should cooperate to develop new publicly available data, analytical tools and training programs. These programs should be created within appropriate ministries and should be commensurate in scale to R&D programs in electric power and transportation decarbonization. Basic, use-inspired and applied research should receive support, as should pilot tests and commercial demonstrations (ideally in partnership with industry and at operating facilities). Industrial heat decarbonization should be added as priorities to Mission Innovation and the Clean Energy Ministerial.
- **Recommendation 3:** *Governments should identify and implement a set of policy actions to accelerate decarbonization of industrial heat, starting with "buy clean" procurement standards.* Such standards are among the most promising and immediately actionable policy tools. Because multiple approaches will be necessary to successfully deliver deep and rapid decarbonization of industrial heat production, governments should assess which policy options best suit their economic, political and natural resource base.

Final thoughts

This Roadmap is an initial foray into an important and complex topic. A core finding of this Roadmap is that more work is needed on this topic. The urgency of climate change requires rapid action. More data, input and technology options for decarbonizing industrial heat are urgently needed.

DISCLAIMER:

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