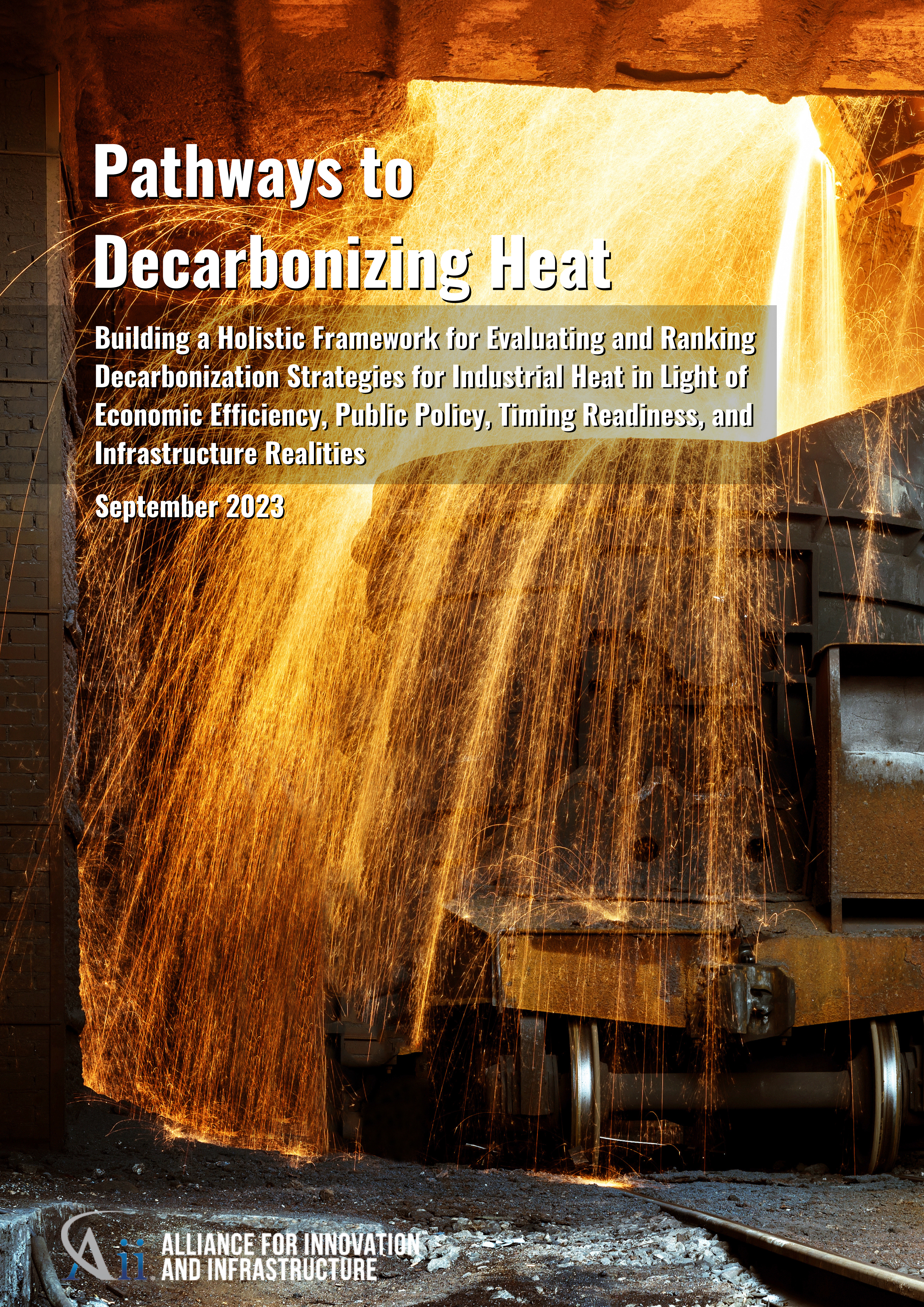


Pathways to Decarbonizing Heat

Building a Holistic Framework for Evaluating and Ranking Decarbonization Strategies for Industrial Heat in Light of Economic Efficiency, Public Policy, Timing Readiness, and Infrastructure Realities

September 2023

ALLIANCE FOR INNOVATION AND INFRASTRUCTURE

Pathways to Decarbonizing Heat

Building a Holistic Framework for Evaluating and Ranking Decarbonization Strategies for Industrial Heat in Light of Economic Efficiency, Public Policy, Timing Readiness, and Infrastructure Realities

Introduction

Heat is arguably the most important form of energy in the United States and the world. Without it, we could not forge steel to build our infrastructure, we could not process raw materials, we could not generate most utility-scale electricity, recycling would not be possible, and our food and water would be unsafe. In its various applications, commercial and industrial heat are central to the economy and our quality of life.[1] This also makes heat-generating sectors concentrated sources of greenhouse gas emissions, as process heat is primarily generated through combustion of hydrocarbons.

These hydrocarbons have built the modern world and continue to run it today. In pursuit of decarbonization, there are some wishing to see the entire economy electrified and to completely depart from hydrocarbons. When these goals are set forth, they often overlook or reject fundamental realities about the scale of our energy dependence, state of our infrastructure, and our true reliance on hydrocarbons. While many present arguments on the economic viability of hydrocarbon alternatives like renewables, very few advocates provide a holistic framework for evaluating an economy-wide decarbonization scheme. We do so here, with a limited approach to the sector producing commercial and industrial heat.

What is often presented is an idealized plan for electrifying the economy. Details like "only x square miles need to be covered in solar or wind farms" give the impression of eminent feasibility, often paired with high generating capacity that impresses policymakers. Usually unstated are the difficulties in bringing such a strategy to fruition, which would likely include: land purchase or use agreements that may require eminent domain; lengthy and protracted litigation over environmental impacts and cost-benefit analyses; substantial permitting and licensing to approve the project; supply chain risks for acquiring the materials necessary for the project; new infrastructure needed to facilitate the strategy, such as hundreds or thousands of miles of high voltage transmission lines; the lifecycle emissions accounting for each step; the timeline to accomplish each step and ultimately be placed into service; and other factors.

What is more, some of the issues further down the chain of events will face the same challenges. For instance, with a potential energy solution that will require transmission lines, not only will there be land acquisition, studies, permitting, and time to build the energy generating infrastructure, but those same factors will then apply to building the transmission lines, potentially adding years and millions in cost.

Before we can rebuild the economy and commit to an unprecedented energy transition, these factors must be written out, explained, understood, and internalized. This framework establishes the tools to do so.

Based on qualitative research and expert analysis, this paper puts forth a framework that will be utilized in future research. This framework factors in cost, environmental impact, and broader legal realities like permitting, construction timelines, and legal challenges. From the analysis conducted here, the most economically and politically feasible pathways demonstrating promise to decarbonize the industrial and commercial heat sector appear to be distributed "low-carbon intensity" production of hydrogen from natural gas and greater development and use of nuclear power. The remaining strategies appear substantially less feasible when evaluating them holistically, but engineering and public policy realities may vary or change over time.

There are at least six factors that must be assessed for each decarbonization strategy. If the strategy is to be implemented effectively, it must perform well in these metrics: (1) cost, (2) environmental impact, (3) regulatory/permitting compliance, (4) timing readiness, (5) logistical feasibility, and (6) power potential.

For the purposes of this paper, we do not evaluate traditional hydrocarbons. These represent the status quo and have a long and proven track record of reliability, power intensity, transportability, storability, accessible supply chains, and affordability. The entire world we now live in was built using hydrocarbons, and that infrastructure is already in place. This paper challenges those who wish to depart from the status quo – often on the basis of carbon emissions alone – to assess the viability and net effects of available alternatives.

Accordingly, because *decarbonization* is the focus, we omit high-emitting methods, such as steam methane reforming or coal gasification to produce hydrogen. Carbon capture was also not considered. These represent the status quo not in need of defense or criticism. As we depart from the status quo, we enter the ongoing dialogue and debate but offer analytical tools needed to holistically evaluate the pathways to decarbonizing. Any viable decarbonization strategy must not threaten a robust and thriving industrial process heat sector necessary for life, progress, and even future production of renewable technologies and electric vehicles.

Cumulative Assessment

The factors presented in this paper are critical to the viability and success of an energy strategy. While some factors are commonly discussed, others are lesser known, and some are entirely ignored in popular debate. Only by evaluating each of these factors and combining them can we accurately assess the feasibility of decarbonizing with each option.

They may cut different ways – the most energy dense may take the longest time to implement, or the least carbon intensive may require the most permitting to go into effect. These must be understood, balanced, and articulated so that policymakers can make better informed decisions. We cannot simply subsidize or penalize energy resources into viability or out of favor, and we must confront the existing and projected infrastructure needs inherent to each strategy. Moreover, a *cumulative cost-benefit analysis* means that, where necessary, the same analysis is conducted for necessary conditions that are not yet present.

This may mean analyzing external factors not directly related to process heat, such as analyzing the factors for new power generation facilities and the transmission infrastructure required to connect it to the grid, employing the six factors to each. This approach demonstrates the ballooning effect that many decarbonization strategies truly entail, but which are not often discussed and allows for a clear comprehensive cost and benefit analysis to be presented.

The framework includes the following six individual factors:

Cost
The strategy must be cost effective, or at least cost competitive. That means it must be economical on its own such that it can be scaled up and adopted voluntarily by the industry or with light regulatory and government involvement. A strategy that relies entirely on subsidies or penalizing competing strategies is not viable.

Environmental Impact
Perhaps counterintuitively, every decarbonization strategy comes with its own environmental impact. This can be viewed positively and negatively – meaning the affect this strategy has on the environment or the relief it provides to the environment. Factoring in lifecycle emissions, waste disposal, material-intensity, recycling, and ecological impact, these strategies must demonstrate that they are a net benefit. Moreover, the most implementable strategy should have the greatest net benefit relative to its competitors.

Regulatory and Permitting Compliance
No infrastructure project – even deployment of renewables – takes place in a vacuum. Long before any wind turbine is generating power or any solar array is installed, a series of regulatory hurdles and permitting tasks must be overcome. These may even include environmental impact studies, cost-benefit analyses, or paperwork filed with multiple redundant agencies at the local, state, and federal levels. Some decarbonization strategies involve complex bureaucratic procedures or rely upon technology that currently has changing or no regulatory guidelines.

Timing Readiness
How quickly can the strategy be implemented? When accounting for the previous factors, some projects may take years to move from conceptualization to generating heat. Not only do builders have to contend with government processes, but they may face landowner opposition, environmental activism (e.g., sit ins, lawsuits, permitting challenges), and cost overruns.

Logistical Feasibility
There are numerous factors to assess when it comes to logistics. Are the raw materials affordable and available for the project? Does this strategy rely, in whole or in part, on supply chains reaching into another part of the world? Does this strategy rely on other or new infrastructure to be built, and if so, what other contingent factors exist?

Power Potential
At the end of the day, the only way the strategy is viable is if it can meet or exceed existing power. Replacing coal with something that is intermittent, dilute, or unreliable for any reason means the strategy is not viable for generating sufficient and on-demand heat at an industrial and commercial scale.

> "Determining which heating process to use is one of the most challenging decisions for manufacturing and industrial managers to make. Variables to be considered include the intermittency of the resource, the cost of the heating application, storage options and process integration." [Processing Magazine]

Assessing the Energy Resources and Technology at Play

Under the umbrella of energy for process heat, there are multiple decarbonization options. These vary in their level and ability of decarbonization, especially when it comes to the different scopes of emissions. This means that some produce energy with zero carbon emission, but have varying carbon footprints to source, build, and deploy those energy options as well as to retire them – or their lifecycle impacts. Similarly, they require varying levels of new supporting infrastructure.

The purpose of this section is not to compare the resources directly to one another, but to walk through each energy resource that provides a pathway to generating industrial and commercial process heat. It will be necessary at points to make such direct comparisons for the sake of illustrating relative differences. In a future report, we will rank these with an objective methodology to offer policymakers the clearest view of the comprehensive costs and benefits of each decarbonization process.

We will primarily evaluate **hydrogen** (including numerous production techniques), **direct heat processes** (including nuclear and geothermal), and **electrification** (including numerous production techniques) as the leading candidates for low-carbon industrial heat potential. Each technique will face the six analytical factors outlined above.

Hydrogen

Here, we are only evaluating so-called clean hydrogen options. Because hydrogen is not naturally occurring at surface level, it must be produced by splitting hydrogen atoms from other molecules, namely methane (CH_4) and water (H_2O). The following hydrogen solutions have the same power potential, but they differ in each of the other five factors.

> "Unlike solar and wind energy, hydrogen is a more natural substitute for fossil fuels in sectors that are particularly difficult to decarbonize (i.e. transportation and industrial) and where the ability to quickly respond to sudden increases in energy demand or to maintain consistent energy supply is critical." [Baker Institute]

Hydrogen from natural gas

While sometimes referred to as "turquoise hydrogen", when combined with CO_2 capture, methane pyrolysis is a scalable technique to produce hydrogen that does not produce carbon dioxide emissions. This is accomplished using one of four methods: microwave, catalytic, plasma, or thermal. On average methane pyrolysis uses three times less electricity than electrolysis.[2]

As a decarbonization strategy, distributed methane pyrolysis at the point-of-use provides the most effective but also visually distinct version of decarbonizing. Logically, it is easier and more effective to capture carbon when and where it is more concentrated. Capturing carbon dioxide from the ambient air (Direct Air Capture) where it is the most diffuse is most energy intensive and most expensive. Carbon capture techniques near the source of combustion (Point Source Capture) where carbon is more concentrated requires less energy and is more cost effective. Yet it is possible to pre-capture carbon at its most concentrated point, by pulling it directly from the methane molecule itself rather than the ambient atmosphere or exhaust fumes. This "pre-combustion carbon capture" utilizing low CO_2 methane pyrolysis separates the atomic components of methane (CH_4) into separate hydrogen and carbon molecules, with the carbon being collected as a solid.

Cost

With this method of producing hydrogen, there are four key cost factors: fuel, energy, equipment, and transportation. The fuel is natural gas. That market price is determined by exploration and production rates and influenced by the broader energy market. Currently, natural gas costs under $3 per million BTU. Natural gas is already the most relied upon resource for process heat because of its availability, affordability, ease of transport, and relatively low emission rate compared with coal. This also means natural gas infrastructure is already in place.

The second is the cost of energy, which varies by process. With some thermal processes, the methane pyrolysis process can be initiated with natural gas, then sustained by its own clean hydrogen. Others require electricity or microwaves. While thermal requires the lowest energy input of the four processes (9 kWh/kg H_2), it requires temperatures between 1,000 and 1,500 degrees Celsius.[3] Plasma, Catalytic, and Microwave techniques each require between 10 and 20 kWh/kg H_2, but demand temperatures of over 2,000 degrees, between 600 and 1,100 degrees, and in the case of microwave, zero degrees.[4]

The third cost factor is equipment to convert the gas into hydrogen by decaying the methane molecule into solid carbon and gaseous hydrogen. The capital investment varies, but dozens of companies are pioneering these techniques. Hydrogen from methane pyrolysis has the potential to produce hydrogen for roughly the same costs as Steam Methane Reforming (SMR)[5] while emitting far less CO_2.[6] The costs and emissions vary by type of pyrolysis selected, but on average are competitive with existing SMR technologies and far lower cost and carbon footprint than electrolysis, given the reduced need for power from the grid and additional infrastructure.[7]

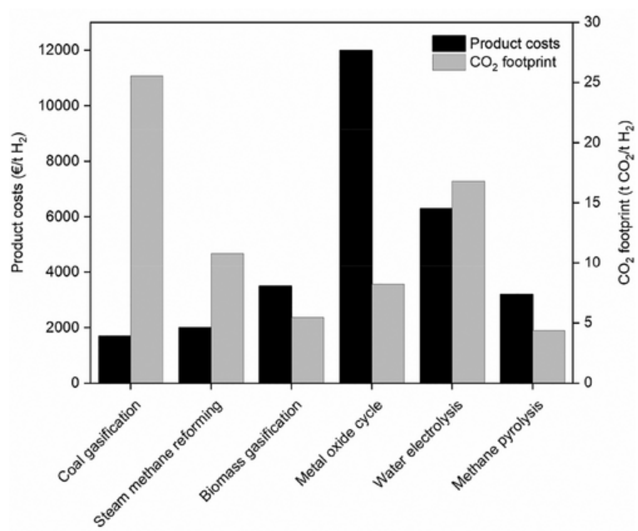


Figure 1: Relative Cost and Carbon Intensities (Industrial & Engineering Chemistry Research)

Whereas adopting carbon capture technology would increase costs for both natural gas users and hydrogen from SMR, methane pyrolysis is cost competitive with both and does not require carbon capture. "The cost of hydrogen produced by a combination of SMR and CCS is estimated to be $2/kgH_2$, while methane pyrolysis is noticeably lower – about $1.5/kgH_2$."[8] Overall, "It is estimated that hydrogen can be produced for $1.72/kg when natural gas is \$3/MMBTU"[9] and as low as \$1 to \$2/kg.[10] Including the other processes to decay methane, the average cost of hydrogen from methane pyrolysis is between \$2.74/kg H_2 and \$5.36/kg H_2.[11] Unlike most other decarbonization strategies, however, methane pyrolysis includes a built-in positive revenue stream. Solid carbon byproduct can be sold to manufacturing, agriculture, and construction sectors as a valuable resource.[12] This positive revenue can offset a portion of the cost and offers a unique environmental benefit by sequestering carbon from natural gas directly into roads, bridges, or other infrastructure.

The fourth cost factor is transportation and storage of hydrogen. If produced hydrogen has to be compressed, driven to the location of the heating load, and stored on site, the associated cost and emissions footprint can triple.[13] By decarbonizing natural gas behind the meter, near the point-of-use, hydrogen can be delivered without any added compression costs or transportation emissions. Where hydrogen is produced centrally, storage tanks, pipelines, and trucks must be factored into the costs.

Environmental Impact

The technique of distributed, behind the meter methane pyrolysis is unique already for its ability to not only produce hydrogen without creating carbon dioxide or other emissions, but by producing a solid carbon byproduct. This results in direct carbon capture and enables easy transport, storage, or use of the carbon. This even offers the potential to create *carbon-negative* heat or power by taking the carbon out of the equation when renewable natural gas is used. In such instances, this technique reverses emissions.

This strategy utilizes natural gas, and the existing natural gas pipeline network has some imperfections. While natural gas does arrive at its final destination with over a 99.999 percent rate, some may inevitably leak throughout the process from well head to final use. These are a function of the status quo and will happen regardless of the energy strategy wherever natural gas remains in use. This technique could counteract that by taking carbon out of the natural gas at its end use and also reversing net carbon emissions with greater utilization of renewable natural gas.

Importantly, a distributed production technique also avoids environmental impacts that other methods require, namely new infrastructure. When centrally producing hydrogen, new facilities must be built, storage tanks must be installed, and transportation methods must be built. The process to do so is material- and energy-intensive on its own and would require environmental disruptions like pipeline construction from the production facility to end users.

Once the hydrogen is ready to be used (whether produced on site or shipped in) it can have immediate effect but is unlikely to supplant all natural gas emissions in the short term. That is due to the need to transition to hydrogen through the use of blending.[14] While not all process heat equipment is calibrated for hydrogen, those using natural gas can begin to add hydrogen to the natural gas stream to begin decarbonizing right away.[15]

Reduction of CO_2 emissions as it relates to hydrogen content in a natural gas stream:	
Hydrogen Content (by Vol.)	Relative CO_2 Emission Reduction (by Vol.)
0%	0%
5%	1.62%
10%	3.36%
15%	5.24%

Figure 2: Blending Effect on Decarbonization (Gas Technology Magazine)

If hydrogen is produced in a centralized location and at scale, there will be building and material needs that are unnecessary with distributed production, such as a production facility, storage tanks, transportation options including pipelines, and more. These each require a substantial energy- and materially-intensive process that can have additional environmental considerations. In particular, by avoiding truck transportation, a distributed methane pyrolysis technique could deliver hydrogen with approximately one-fifth the carbon emissions as centrally produced green hydrogen from all renewable-powered electrolysis.[16] If entirely renewable natural gas were used with distributed methane pyrolysis, this would deliver a negative carbon balance.

Regulatory and Permitting Compliance

The primary permitting concern is a patchwork of local and state level air quality environmental rules that do not measure emissions but use natural gas as a proxy. In this case, even with distributed hydrogen production, a greater amount of methane is used by a facility, but some or all of the carbon is stripped out. However, due to rigid environmental rules that only calculate the one-way natural gas flow, they rate the facility as increasing its emissions (because they do not measure actual emissions). In certain locations, this is a barrier for methane pyrolysis because even though in reality this process lowers or even eliminates emissions, inflexible and inaccurate standards erroneously view it as increasing them.

Where there are no air quality standards regulations that closely track emissions, there are no regulatory barriers to installing and implementing a methane pyrolysis technique, because in many cases, it is simply a device or equipment installation added alongside existing facilities that does not require construction, retrofitting, or other overhauling. Where methane pyrolysis is used to centrally produce large quantities of hydrogen, the facility would be under additional regulatory and permitting burdens to build the production center, storage tanks, and transportation options.

Finally, there are few regulatory hurdles for the handling, storage, or transport of physical carbon. It is not classified as a hazardous material but may require additional trucking or other transport options to remove it from the site.

Timing Readiness

This process is additive to existing industrial heat processes, meaning it does not require entirely new processes. It can be deployed immediately alongside natural gas heat sources. In most cases, equipment is calibrated to burn natural gas only, so switching entirely to hydrogen is not practical. In this case, blending is used, where hydrogen is mixed into the fuel blend and burned alongside natural gas. While depending on the blend, this can offer immediate reduction in carbon intensity, the transition of blending to full hydrogen may take years.

With distributed hydrogen production, which can be done on-site, there is no waiting time to build out hydrogen pipelines or storage tanks. This also renders added electricity demand unneeded, which reduces the risk of energy scarcity or reliance on new transmission infrastructure to be built. To the extent that natural gas is used to produce hydrogen centrally and at scale, depending on the technique, there may be years before sufficient infrastructure is in place.

Logistical Feasibility

This strategy is dependent on access to affordable natural gas. While this can be impacted by domestic policy that opposes hydrocarbons, natural gas is nevertheless abundantly available in domestic geologic reserves and collection of renewable natural gas extends this in perpetuity. There is limited supply chain risk to acquiring gas and a multimillion-mile network of transmission and distribution pipelines is already in place. There is no need for new pipelines to be built – or retrofitted for hydrogen – because the distributed strategy utilizes the natural gas infrastructure already in place to generate hydrogen on-site, short cutting many of the issues above.[17] Where centralized production is preferred, considerable costs and challenges arise, as discussed more fully in the section on electrolysis, which has received more attention at larger scale.

One clear drawback to this strategy is that the industrial sector is unlikely to adopt clean hydrogen technologies at scale without economic or policy incentives.[18] Clean hydrogen must become competitive to be used. Only those choosing to lead in the decarbonization space or operating under decarbonization mandates are likely to begin using a method like methane pyrolysis. Because it could require twice as much natural gas, many may opt to continue the status quo.

Lastly, the solid carbon produced as a product of methane pyrolysis must be addressed. Carbon can be used in many applications but there currently is only a nascent market to make use of the huge amounts of carbon that would be generated from full-scale methane pyrolysis. There is potential to generate tens of millions of tons of carbon as a byproduct of hydrogen production at an industrial scale, but the current global market only consumes about 16.4 MMT.[19] This presents a unique opportunity for a new market to utilize carbon as an industrial or construction material, reducing demand for existing materials and lowering the carbon intensity of others. There is also an opportunity to sequester carbon directly into our roads, bridges, and other infrastructure.

Power Potential

Hydrogen has the energy density and thermal potential to compete with natural gas. Pure hydrogen burns at temperatures consistent with natural gas[20,21] and with greater energy potential per unit than other traditional fuels.[22] Hydrogen can be blended or burned alone and meet the needs of process heat across a range of temperatures, depending on the specifications on site.

As of 2022, over 40 percent of the U.S. industrial energy sector is served by natural gas.[23] That means that rather than rebuilding a new energy sector to decarbonize industry, we could decarbonize the energy as it is fed into their systems with minimal disruption and no additional infrastructure buildout needed to support the solution.

In sum, a distributed hydrogen production that leverages existing natural gas infrastructure avoids the costs, regulations, and technical issues inherent to many other strategies. There would be no new electricity infrastructure needed, no specialized hydrogen pipeline or storage tanks needed, and no new permitting to confront. This strategy is deployable now and capable of decarbonizing in the short run. The challenges to this model include recalibration or retrofitting of certain equipment to optimize the use of hydrogen where natural gas was the primary intended fuel. Additionally, this strategy would use more natural gas than currently needed to supply industrial heat, because the pyrolysis technique itself is energy-intensive. Finally, because of blending, this strategy would not immediately stop carbon dioxide emissions in the industrial heat sector but would lessen them to a small extent immediately and to a greater extent over time.

Hydrogen from water:
Classical green hydrogen is produced from water and electricity in a process known as electrolysis. Similar to methane pyrolysis, electrolysis does not produce carbon dioxide and instead splits water molecules ($2H_2O$) to result in hydrogen ($2H_2$) and oxygen (O_2).

This is accomplished using one of several methods: polymer electrolyte membrane (PEM), high temperature electrolysis (HTE), alkaline electrolysis cells (AEC), anion exchange membrane (AEM), or solid oxide electrolysis cells (SOEC). On average electrolysis uses three time more electricity than pyrolysis techniques.[24] To be designated as clean or green hydrogen, the source of the electricity must also be low-carbon, such as nuclear, wind, hydropower, or solar.

> "Electrolysis is a promising option for carbon-free hydrogen production from renewable and nuclear resources … can range in size from small, appliance-size equipment that is well-suited for small-scale distributed hydrogen production to large-scale, central production facilities." [US Dept of Energy]

Cost
A key benefit of electrolysis is the avoidance of natural gas or other fuels. The cost to produce hydrogen largely come down to water, equipment, and electricity. There are clear advantages and also drawbacks to this model, which also vary by location.

Access to water is a struggle in some places, while it is abundant and affordable in others. This may constrain the use of hydrogen production through electrolysis in locations like the Southwest – although ironically, that is the area with the most concentration of solar and geothermal energy, where it is more cost effective to supply clean power. That presents a second challenge. Because electrolysis is only *green* if facilitated through power from renewable sources, this puts a premium on electricity costs and requires a well-connected and resilient power grid.

Beginning with water, “9 liters (L) of water are required to produce 1 kilogram (kg) of hydrogen via electrolysis” but the entire production process necessitates an additional 10 to 20 L/kg.[25] While this amount of water adds up at scale, it is still half the water requirement for nuclear power.

When factoring in equipment and capital costs, once operating, electrolysis can produce hydrogen at a cost of between $4 and $6 per kg of H_2.[26] “Low-cost clean hydrogen via electrolysis will entirely depend on the availability of low-cost renewable [or nuclear] electricity of less than $20/MWh.”[27]
While current electricity costs and grid infrastructure mean a relatively higher cost of hydrogen with electrolysis, costs are projected to fall by 50% for producing hydrogen by PEM electrolysis by 2030.[28] Solar could cost as little as $22/MWh by 2035, while wind could cost as little as $24/MWh by 2025.[29]

The LCOE of nuclear power plants with a lifetime extension will be cheaper than that of wind or solar in 2040, but newer nuclear plants will likely have higher LCOE than solar or wind.[30] Barring the improvement and deployment of new nuclear reactors this decade, “the clean energy transition will become far more expensive, requiring $1.6 trillion in additional investment.”[31]

A final cost, which is contemplated below, is the need for other infrastructure and transportation options.

Environmental Impact

Because of its electricity demand, creation of hydrogen from electrolysis can actually have a higher carbon footprint than traditional SMR because of the impact on the electric grid.[32] This is why electricity must come from low-carbon or renewable sources to produce green hydrogen, but there are still grid impacts.

Deploying the new capacity needed to power electrolysis will mean wind, solar, and other energy farms disrupting natural ecosystems and also require extensive increases in mining around the world. The needed transmission infrastructure, which also has high energy and material demands, will then need to be constructed. clean energy technology, while producing no or low CO_2 emission during power generation, requires a considerable increase in mining and mineral extraction.[33] Wind energy infrastructure is more mineral intensive than any other form of electricity generation, despite its low emissions, owing to its scale and the raw materials needed, including steel, concrete, fiberglass, and more.[34]

Not only do these renewable technologies and infrastructure have upfront costs and impacts, but they must be retired and disposed of as well. This is far down the chain from the direct production of hydrogen through electrolysis, but it is the natural consequence of increasing the use and capacity of renewables to do so.

Then there are the material needs to facilitate electrolysis itself. For instance, PEM electrolysis (expected to be grow to around 40 – 45 percent of the U.S. hydrogen market) is highly mineral intensive. Estimates predict that within the decade, PEM electrolyzer demand could require up to 30 percent of the global iridium production.[35]

Beyond mining for raw materials, water can also be a scare resource. As hydrogen production would be a new source of demand, this would compete with existing industrial water use, municipal safe and wastewater demand, and other commercial needs. Notably, if electrolysis is facilitated by nuclear power, there is substantial water use in the system. By contrast, methane pyrolysis can be accomplished without water or renewable power (depending on the method) and still deliver low, no, or negative carbon hydrogen.

A final environmental impact to consider is the movement of the hydrogen. On-site production offers the most environmentally friendly option, but does not take advantage of scaling. When produced at a central facility, hydrogen will require energy- and material intensive storage tanks and compression equipment. The hydrogen will then be placed into new pipelines (which must be built) or on trucks (which will have their own emissions). Even if electric vehicles are used, the overall energy and material intensity must be factored in.

Regulatory and Permitting Compliance

There are at least three things to consider: permitting for the electrolysis hydrogen production facility, access to (and permitting for) renewable energy to supply power, and supporting infrastructure needed to bring the new hydrogen to market.

While state-level regulations and laws are likely to result in disparate treatment of hydrogen around the country, the federal agencies with some hand in the production or oversight of hydrogen include the Department of Energy (DOE), the Federal Energy Regulatory Commission (FERC), the Pipeline and Hazardous Materials Safety Administration (PHMSA), the Environmental Protection Agency (EPA), and the Occupational Health and Safety Administration (OSHA).[36]

Depending on the size and scale, there may be environmental studies and regulatory compliance simply to build a production facility. Given the need for pressurized storage tanks and other industrial components, these will likely be closely regulated.

To produce the clean power needed for green hydrogen, there are considerable regulatory hurdles (explored more fully in Electrification section below). Similar to water use, the arrival of a robust electrolysis sector represents new demand for power. That will have to be facilitated by new renewable infrastructure capacity yet to be installed. Whether those are wind farms, solar arrays, hydropower facilities, nuclear plants, or another low-carbon power source, their footprint and location will go a long way in determining the extent of permitting and regulatory compliance.

Nuclear energy in general is known to have some of the most stringent and comprehensive regulations and security of any industry in the world. This means that everything is done safely and well researched but can also take longer and involve more complicated regulations. While nuclear may receive heightened scrutiny, every energy project faces detailed review and approval processes. Even new wind and solar farms can take as long as a decade of environmental review in accordance with the National Environmental Policy Act (NEPA) and other laws.

Once the hydrogen has been produced, if done centrally, it must be stored on-site or transported through a network of new transmission and distribution pipelines. From a permitting and regulatory perspective, this will entail substantial time and paperwork. For existing natural gas pipelines, the process entails:

> Planning for new capacity must begin far in advance of transporting the first barrel of oil, refined petroleum product, or first cubic foot of natural gas. Pipeline companies must determine possible routes for the new pipelines; acquire the right-of-way (ROW) to build, operate and maintain the pipelines; engineer the actual system designs; and construct the pipelines. Each of these steps are subject to rigorous regulatory reviews and approvals. Construction can only begin after the route selection receives regulatory approval, the ROW is obtained, and the system design is completed.[37]

The "rigorous regulatory reviews and approvals" can sometimes entail redundant permits and approvals from local, state, and federal agencies and often involve environmental impact studies, public health analyses, and economic reviews. Primarily, the Federal Energy Regulatory Commission (FERC) would approve pipeline plans federally[38] while once in operation, its safety would be regulated by the Pipeline and Hazardous Materials Safety Administration (PHMSA).[39] Depending on the route, there may be additional environmental studies to complete for federal land or negotiations to settle with landowners.

Timing Readiness

While hydrogen production through electrolysis is taking place now, it is not scalable without considerable investment. Assuming industry is ready to receive the hydrogen, there are factors not yet in place restricting the mass production and distribution of this type of clean hydrogen. Those factors, discussed in part above, primarily include the renewable electricity generating capacity to meet increased clean power demand and the transportation network to move the hydrogen.

Whether tied to the grid or directly powered, facilities producing hydrogen will need clean power. That power will have to be new – not taking it from the existing economy – and thus adding to the total energy produced/consumed each year in the United States. According to researchers, "annual production of a million tonnes of green hydrogen requires 10 gigawatts of electrolyzers, 20 gigawatts of renewable power generation, and $30 billion in investment (also known as the '1-10-20-30 rule')."[40]

Utility-scale wind and solar projects take an average of around four years, although extensive regulatory and permitting delays often push this toward a full decade. Nuclear power also takes around 10 years. If not produced on or near the site, this clean power will have to be tied to the grid with transmission lines. These can also take up to a decade to be approved and built. Because the power source and transmission are not built by the same company, they may not be timed together. If completed consecutively, it could take as long as two decades, while if done concurrently, the required infrastructure could be in place within 10 years.

A caveat to this timeline is that if new demand for power is met with hydrocarbons, the portion of renewables on the grid could be dedicated to hydrogen production. It is also the case that many wind, solar, and other renewable projects are already in the works and will increase annual U.S. renewable capacity over time. These factors are needed to produce the hydrogen, but another factor could forestall the readiness of the strategy as well: transportation.

While electrolysis can be accomplished at varying scales, it is predominantly being pursued at centrally produced facilities in regional hydrogen hubs. This will require storage tanks – both on site and at customer locations – as well as transportation options like trucks and pipelines.

As discussed in the regulatory factor above, reviews and approvals can take years. In some cases, even when a project has received all relevant permits, it can have them revoked or be subject to continual litigation. The Mountain Valley Pipeline was reported in 2017 as a 300-mile, $3.5 billion natural gas pipeline. After seven years, it was most recently reported at more than twice the cost of $6.6 billion; and it is still not in service.[41] While every pipeline project has its own particular facts, the average pipeline construction can also take seven to nine years.

Logistical Feasibility

Many of the challenges for widescale green hydrogen production have been articulated above, but certain aspects of those contain additional points of analysis. The renewable energy required relies substantially on supply chains and materials extending into other countries as well as fluctuating commodity prices. This creates uncertainty on multiple fronts, including availability of materials, costs, and shifting regulator or even foreign policy.

> "This is because policy-makers have clearly understood that no energy transition is possible without transmission."
> [World Economic Forum]

The long-term viability of electrolysis relies upon the price of electricity. It is estimated that up to 200 GW of renewable energy sources would be needed by 2030 to support clean hydrogen production with water electrolysis.[42]

The need or more power can be explained with reference to nuclear capacity rather than wind, solar, and other renewables. To match current hydrogen production of 10 million metric tons (MMT), half of the 95.5 GW produced at nuclear power plants in the U.S. would have to be used.[43] In other words, half of all the nuclear reactors in the U.S. would be needed to match current hydrogen production using electrolysis. This is not to mention increased production needed for the future. New planned power is expected to grow the pie and enable more electricity to be available for hydrogen production and other purposes.

Other logistical concerns to transport hydrogen by pipeline include the potential to simply not have available land. The Summit Carbon Solutions pipeline in the northern plains presents a contemporary example of land acquisition challenges, most recently having siting and other permits rejected by state panels in both North and South Dakota.[44] It may end up requiring eminent domain, costly rerouting, or special federal approvals. This will also increase costs and delay the timeline. On average, the "estimated 2021-22 $/mile costs for new onshore [pipeline] projects as filed by operators with FERC were $8.7 million/mile."[45] The extraordinary cases that face additional landowner opposition, environmental activism, lawfare, and even supply chain disruptions may be far higher. For instance, at a reported $6.6 billion for 303 miles of pipeline, the Mountain Valley Pipeline is currently estimated at $22 million/mile.

Building a new pipeline requires: route selection, regulatory process, design, pipe fabrication, site preparation, pipe stringing, trenching, bending, welding and weld inspections, field coating, lowering and backfilling, pressure testing, and site restoration.[46] The U.S. pipeline network already includes nearly 3 million miles of infrastructure – which goes to establish that pipelines are a tried and true method of transport and we know how to build them. But in recent years, greater opposition has arisen for seemingly each and every pipeline. Lastly, while some of the existing pipeline may be able to facilitate hydrogen movement, it is likely to need its own dedicated infrastructure in the future.

Power Potential

Hydrogen has the energy density and thermal potential to compete with natural gas. Pure hydrogen burns at temperatures consistent with natural gas[47,48] and with greater energy potential per unit than other traditional fuels.[49] Hydrogen can be blended or burned alone and meet the needs of process heat across a range of temperatures, depending on the specifications on site.

As of 2022, all renewables together provided 21.5 percent of utility-scale electricity. Nuclear power provided an additional 18.2 percent on its own. A surplus[50] equivalent of 1.5 percent also came from small-scale or distributed photovoltaic solar, which could be the type to provide direct power rather than grid-tied power supporting certain hydrogen production facilities. Primarily, there must be growth in deployment of renewable technology that not only has a high capacity, but high electricity generation and storage.

In sum, producing hydrogen from electrolysis is a highly prioritized pathway for decarbonization that comes with a number of contingent factors. Presently, the costs are too high to compete with hydrocarbons or even hydrogen produced with methane or coal because green hydrogen is selective to only utilize renewable power. With all of the relevant infrastructure in place, potentially one to two decades on, this type of hydrogen can be a core source of power for process heat and other applications with ultra-low lifecycle emissions.

Direct Heat Processes

There are other ultra-low carbon methods of producing heat that can be used directly for process heat. Most electricity comes from generating heat (often through combustion) in order to produce steam that spins a turbine to generate electricity. But why build nuclear and geothermal plants just to turn that heat energy into electricity to send it through transmission infrastructure just to have it come back as electrified process heat? Instead of that inefficient process, we can use these sources directly. This may require scaling down certain infrastructure components and having on-site or near-site access for the heat needs.

Direct Heat from Nuclear

Nuclear fission is one of the most versatile energy production methods in existence. Not only does the atomic energy extraction process unleash vast amounts of heat, but it can operate with the same fuel for years with virtually uninterrupted capacity factor running day and night. Due to the considerable energy density within enriched uranium pellets assembled into fuel rods and placed into the reactor, there is more than enough potential energy to produce process heat, electricity, and even aid in desalination and other commercial and industrial tasks.[51]

Cost

While intensive to build and requiring rigorous engineering plans and regulatory approvals, nuclear delivers cost-competitive energy because of its high capacity factor and the multi-year life span of fuel rods used. Upfront costs and insurance are relevant for expanding nuclear and building new power plants, but the levelized cost per Btu or kWh is what is primarily relevant.

With a horizontal, compact high temperature gas reactor, "a survey of low-carbon industrial process heat technology showed the HC-HTGR can deliver a highly competitive levelized cost of heat in the range of $6.13–12.48/GJ."[52] Other sources indicate that "With a cost of electricity of 5.82 cents per kW_eh, the cost of heat would be equal to 7.15 $ per $MW_{th}h$ (0.715 cents per $kW_{th}h$)."[53]

With its long onramp and high startup costs, "nuclear power may be more expensive on an LCOE basis than either coal or natural gas but that there are plausible scenarios under which nuclear is competitive with, or outperforms both."[54] Moreover, nuclear is primarily used for electricity in the United States, which requires generating heat then using it to heat gas or water that spins a turbine. Using the heat directly for process heat, concurrently, or recycled after generating electricity may drive the cost down considerably or otherwise provide far higher value for the same cost.

Environmental Impact

As a carbon-free generating source, nuclear is on par with renewables while offering far higher capacity and stable access to heat and power. Nuclear power emits an average of 65g CO_2 per kWh for all stages of production (lifecycle), which mainly accounts for construction of power plants and acquiring, processing, and transporting the uranium used. This is slightly higher per kWh than than wind or solar, but a nuclear plant operates for twice as long as wind or solar infrastructure. Where decarbonization is concerned, utilizing nuclear is the most feasible way to ensure the same (or higher) heat and power at far lower lifecycle emissions than hydrocarbons, which typically emit 600 to 1200g CO_2/kWh.[55]

It may seem counterintuitive to use nuclear heat for hydrocarbon applications, but it can increase efficiency and prevent CO_2 emissions that will occur anyway due to demands to maintain the systems we already rely on. Using conventional processes, two tons of oil shale can be used to produce one ton of product with 2.5 tons of CO_2 emissions, but with nuclear process heating and 12MWh of electricity, that same two tons of oil shale can be made into 2 tons of product and zero CO2 emissions.[56]

Table 2. Decrements of Carbon Dioxide Emissions from Industrial Processes

Process		Carbon Oxide Emissions
Heavy Oil Recovery	Conventional	2 ton OIP→1 ton Product + 2.5 ton CO_2
	Nuclear	2 ton OIP + 12 MWh→2 ton Product + no CO_2
Methanol Production	Conventional	300 m^3 Gas→1 ton Product + 1.5 ton CO_2
	Nuclear	300 m^3 Gas + 3 MWh→2 ton Product + no CO_2
Oil Shale	Conventional	2 ton Shale→1 ton Product + 2.5 ton CO_2
	Nuclear	2 ton Shale + 12 MWh→2 ton Product + no CO_2
Biomass Conversion	Conventional	2 ton Biomass→1 ton Product (CH_3OH)
	Nuclear	2 ton Biomass + 10 MWh→2t Product

Figure 3: Decarbonization Effect of Nuclear (Nuclear Engineering and Technology)

Outside of carbon emissions, nuclear plants require mining for uranium and rely on energy-intensive supply chains. These can be disruptive to the environment, but due to its unique energy density and capacity factor, nuclear power has the smallest land use footprint of any energy source besides geothermal (including renewables and hydrocarbons).[57] This minimal footprint means less disruption to plant and animal life, limits the need to clear land, and allows for other land uses nearby.

A concern that arises with nuclear heat or power is radioactive waste. This is an issue that requires a policy solution. The engineering problem has been solved by storing the relatively small proportion of highly radioactive waste in concrete and steel canisters and held on site. As a policy matter, a centralized or federally designated disposal zone is needed. Nuclear waste is safe to handle and store and there are no deaths attributable to nuclear energy in United States over its entire history.

Regulatory and Permitting Compliance

The primary regulatory entity overseeing U.S. nuclear energy is the Nuclear Regulatory Commission (NRC), which reviews and issues licenses, oversees commercial nuclear materials, inspects nuclear facilities, and sets guidelines and safety codes. The NRC also oversees the decommissioning of reactors, tightly regulating the process from cradle to grave.

As a highly regulated industry, one could view nuclear as too rigidly policed. It can be the case that regulatory oversight leads to cost overruns, reengineering with higher standards, and project delays. But it is also possible that too little or unclear regulation is in part to blame. As the National Academies explains in a recent report:

> The NRC requires compliance with detailed regulations that are tailored to light water reactors (LWRs). The existing regulatory requirements may be inappropriate or inapplicable to non-LWR designs and some of the advanced designs present new regulatory issues.[58]

There is also the possibility that after receiving a construction permit and before or during the application for an operating license, that a challenge arises to the design requiring both appeals and the potential for retrofitting the reactor well after construction began.

Internationally, advocates for nuclear point to three sources of regulatory slowdowns holding back nuclear power as: an unlevel playing field among energy resources, an unpredictable and inconsistent licensing regime, and an ineffective safety paradigm.[59] Policies that unfairly advantage competing low-carbon strategies or disadvantage nuclear for its perceived safety risks and waste are not themselves regulatory barriers, but are policy-generated inefficiencies. Some contend that regulators overvalue safety relative to economic efficiency, not that safety is not critical, but that too many redundancies and over-protections hamstring the viability and growth of the industry.

Most of these regulatory considerations involve building new reactors in general or for electricity in particular. As it pertains specifically to process heat, there may be public policy changes that need to be written. Several places in the world already use nuclear reactors for district heating, oil production, and industrial heating. However, it is so far untested on a commercial scale in the U.S.[60] A regulating scheme for nuclear process heat has not yet been established. Locating a high-temperature gas-cooled reactor (HTGR) close to the industrial process will require special licensing and engineering considerations.[61]

Timing Readiness

The United States currently has 93 commercial nuclear reactors at 54 nuclear power plants. The most recent began operating this summer (2023), but took 10 years to open after construction started. The previous new reactor to enter operation was put into service in 2016, while its construction inception extends all the way back to 1973.

Nuclear reactors and power plants are more strictly regulated than other power generating infrastructure. Most nuclear power plants take around eight years to plan and build in the U.S., though around one-third take longer.[62] Despite no full meltdowns and zero deaths in U.S. nuclear history, it is not uncommon for nuclear projects to overrun both their proposed budget and timeline by as much as 100 percent each as regulators raise standards, insurers reassess risk, and activists challenge the project.

With a decade or more to wait for new reactors to come online, new nuclear power would ordinarily be dependent on electrical transmission lines to carry the power onto the grid to end users. For direct heat applications, this is avoided, but the reactor must be in proximity to the place process heat is needed. Traditional nuclear reactors are large-scale and high-capacity technologies designed for the grid. Process heat may be best served with small modular reactors, which can be deployed to industrial centers where heat is needed rather than require heat transfer that may depend on new infrastructure.

Small modular reactors (SMR) are expected to be on the market by 2030 at varying scales and capacities. This may push the timeline on precision nuclear process heat by 10 years, and more if additional regulatory scrutiny is required.

Because nuclear has historically been used almost exclusively for electricity, there may also be some readiness challenges on the industry side. Fortunately, many process heating applications are already adapted for a transition or opening for nuclear. District heating, seawater desalination, oil sands, chemical production, and soda ash production all require a "low level of engineering" to implement. Aluminum production, pulp and paper production, oil refining, ammonia production, and hydrogen production require "middle level of engineering" effort.[63]

Logistical Feasibility

Nuclear experts express that there are "myriad technical, regulatory, economic and societal hurdles must be overcome"[64] to expand nuclear in the United States and meet decarbonization goals. The aging fleet of nuclear reactors means that we will need to develop and deploy far more nuclear assets in the near future to replace and grow the nation's nuclear portfolio.

Meeting future energy demand and decarbonization goals (including hydrogen production, direct heat, and electrification) will require advanced nuclear and small modular reactors in addition to traditional light water reactors and others. The timeline for any new nuclear project is around a decade, and with the prospect of decommissioning older reactors in the coming years, this presents a considerable challenge to power readiness.

The U.S. imports approximately 88 percent of its uranium. Even with stable foreign relations, this presents a supply chain risk for needed materials that could be disrupted by inflation, energy crises, war, a pandemic, or other forces. The steady supply to date is not a guarantee for the future, so policymakers should ensure the long-term viability of access to uranium.

To build new plants require extensive and often evolving regulatory compliance and licensing. The lack of clarity, especially around new and emerging technologies, may lead to feasibility challenges and delays. This will drive up cost, which could also discourage insurers and investors, which could have a compounding effect.

Fortunately, using nuclear energy for direct process heating applications avoids the need to build new transmission infrastructure. It does require proximity to the industrial sector utilizing the heat, either with short, insulated pipes or by placing a new reactor on-site. These likely come with many unforeseen regulatory challenges and technical issues.

When it comes to the feasibility of using the nuclear heat, different types of nuclear reactors produce different amounts of heat, and therefore can be used for different heat processes. Pressurized water reactors, boiling water reactors, pressurized heavy water reactors, and light water reactors are all capable of heating water up to 300 degrees

Celsius (572°F), whereas other reactors such as the high-temperature, gas-cooled, graphite-moderated reactor (HTGR) can handle temperatures of up to 950 degrees Celsius (1,742°F).[65] Most heating processes could feasibly use nuclear heating, but the hottest processes such as glass and cement manufacturing require temperatures even higher (as high as 2,500 to 3,000°F).[66]

Even advanced HTGR nuclear reactors will be limited in the heat they can produce. The maximum tested reactors can only generate process heat temperatures of around 950 degrees Celsius (1,742°F). Some processes like forges and cement production will never be able to use exclusively nuclear energy for heating. For temperatures over 1,000 degrees Celsius (1,832°F), electrical resistance heating, hydrogen, and biofuel are better low-carbon alternatives.[67]

Power Potential

Nuclear power is capable of generating immense amounts of energy. Before it produces electricity, this energy exists in the form of clean heat. Nuclear reactors can reach temperatures of 1,700°F and higher. Whether utilizing gas or liquid, this heat can be transferred and used in a wide range of process heating and industrial applications. It may even be useful to use nuclear to preheat gas or water for other processes, simply by running it through or near nuclear operations.

Nuclear power is responsible for generating 18.2 percent of utility-scale electricity in the United States. Globally, nuclear provides a higher share of some country's mixes – as much as 63 percent of the energy mix in France – but the U.S. generates more than twice as much power as the next country. The 772 billion kWh of energy domestically is used for electricity; however, electricity is only one use of nuclear power. Heat from nuclear fission can also be used for "seawater desalination, hydrogen production, district heating and process heating for industry (glass and cement manufacturing, metal production), refining and synthesis gas production."[68]

In sum, nuclear offers substantial potential for decarbonization because it is a carbon-free power source with low lifecycle emissions. Nuclear is positioned to generate direct process heat for a wide array of industrial and commercial purposes as well as clean electricity to electrify the process heat sector or produce hydrogen. With greater reliance on nuclear, and the promise of small modular reactors, the ability to expand the economy without increasing emissions is achievable. The challenges inherent to nuclear are primarily policy and political/cultural, not engineering or technical challenges. Despite safe operation and safe waste disposal, the public and policymakers are hesitant towards nuclear technology. Other policy challenges are the long and costly permitting and approval process. Finally, with more nuclear power comes the need for more transmission lines, water use, and pipe to transfer heat, which will themselves face cost, regulatory, and logistical challenges to address.

Direct Heat from Geothermal
Natural heat from the earth is available to extract and has been utilized for small heat applications and electricity generation for decades. Use of geothermal for direct process heat may help expand decarbonization goals either by displacing the need for greater hydrocarbon use or supporting complementary renewable deployments to meet demand in this industrial sector.

> "Commonly, geothermal, biomass and solar sources of heat can be used for air heating or water heating.... Industrial processes have different requirements for industries and products...more than half of the industrial heating requirements can be accommodated to by heat levels less than 750°F." [Processing Magazine]

Cost
Because heat from geothermal is used in heat pumps, but not necessarily at scale for industrial processes, there is little comprehensive data on cost. While electricity from geothermal power plants has an average levelized cost of $0.07/kWh globally, the cost in the U.S. is likely slightly higher. This cost includes utilizing a working fluid to spin a turbine to generate electricity. In theory, the heat itself has a lower cost per Btu or kWh equivalent.

Another aspect of the cost of geothermal heat is the equipment and capital investment needed to harness it. A heat pump used in residential or commercial application has an average cost around $12,000 but can extend beyond $30,000. These are relatively small scale appliances, with geothermal plants requiring multi-million dollar investments.

For residential and commercial space heating applications, heat pumps have a significantly larger capital cost than electric baseboard and natural gas. A geothermal heat pump may cost as much as six times more than mid-efficiency natural gas furnaces. However, the heat pump has an average annual heating cost far lower than natural gas or electric.[69]

The process does not require fuel but utilizes drilling to access heat lower in the earth. This heavy equipment can have high capital costs comparable to certain drilling capital in the oil and gas sector.

Finally, geothermal heat can be considered from a cost savings perspective when used to preheat liquid or gas that will require other fuel-based or electric heat application. The heat still has a cost, and unless it can be used concurrently, would prevent the generation of electricity.

Environmental Impact
There are no emissions associated with geothermal energy. Still, there are lifecycle emissions associated with construction, operation, and transportation from the facilities. These range from 11 g CO2eq/kWh to as high as 47 g CO2eq/kWh, but these are dependent on the type of technology employed.[70] The median rate is 37g CO2eq/kWh, putting it roughly between the carbon intensity on a lifecycle basis of concentrated solar power and photovoltaic solar power.[71]

Geothermal energy requires the least land footprint of any energy source. While they are not high producing, they still use less land per MW than the others, including as small as one-fifth of a nuclear footprint. This is partially attributed to having no fuel or equipment to generate heat, with drilling used to access the planets own internal heat. The small footprint also minimizes environmental disruptions, leading industry experts to remark on the abundance of wildlife right outside the facilities.[72]

A unique feature of geothermal is that its waste product potentially results in inadvertent extraction of valuable minerals. During the drilling process, sludges often contain zinc, silica, sulfur, and lithium.[73] These can be extracted from the mud and sold to generate revenue, offset costs, and provide supply for critical industries.

Considering geothermal as a method of process heat rather than electricity may decrease the need for new transmission infrastructure. However, not every location is well suited for geothermal energy extraction, narrowing the eligible locations that must also be in close proximity to where process heat is needed. This may mean disrupting the local environment near a manufacturing center or could potentially cause seismic disruptions from the input and extraction of water, steam, and heat.

Regulatory and Permitting Compliance

As with all major infrastructure projects, there are regulatory barriers to overcome. With 90 percent of geothermal projects taking place on federal lands, this comes with additional scrutiny and more parties to engage with.

Leases and permits must be acquired from the Bureau of Land Management like drilling for oil and gas. However, unlike exploration and production for hydrocarbons, which was streamlined by Section 390 of the Energy Policy Act of 2005, geothermal energy projects and accompanying drilling must contend with the full bureaucracy.[74] Despite being carbon-free and generating efficient electricity with very few negative externalities, it has been described as facing “regulatory barriers more stringent than for oil and gas.”[75]

This means conducting all required environmental assessments and stakeholder engagements prescribed in NEPA and awaiting government approvals in the meantime. The average geothermal project is estimated to be subjected to six 10-month NEPA environmental reviews during before receiving final approval.[76]

Timing Readiness

Not every location is suited for geothermal energy extraction. Geologists survey to identify potential sites, which can take months or years. The primary timing issue is federal environmental regulation, and NEPA in particular. The average geothermal project takes eight years to complete this process before generating power.[77]

Because most geothermal activity takes place on federal lands, projects must work with the Bureau of Land Management and comply with numerous federal regulations. This long regulatory process means no new power or heat from geothermal for nearly a decade, and with the relatively small amount already in service, it is not enough to make an impact in decarbonizing without an uptick.

Moving away from the industrial-scale approach, geothermal technology is already well developed for building heat pumps and low temperature heating and cooling technology. Additionally, the deployment of heat pumps is increasing at a rapid pace in developed economies.[78] This distributed approach may end up making a larger decarbonization impact than higher capacity and centrally located geothermal projects. However, it may limit the use for heavy industry applications until innovation breakthroughs and public policy reforms occur.

Logistical Feasibility

Expansion of geothermal energy is a challenge. Despite being a low-carbon energy source that emits no CO_2 during power generation, it is such a small proportion of the energy mix that is remains small in the public awareness. This leads to a lack of investment as well as little public policy attention to streamline the process or incentivize expansion.

When geothermal is pursued, it faces multiple challenges,

> Exploring, discovering, developing, and managing geothermal resources is inherently complex and can have greater risks and upfront costs than other renewable energy technologies. Geothermal can also face barriers in land access, permitting, and project financing. In addition, all geothermal resources share a key non-technical barrier: lack of awareness and acceptance.[79]

An additional challenge is often proximity to transmission infrastructure. Every new energy project must be located on-site with its end user or connected to some transmission infrastructure and the wider grid. For geothermal, it is often difficult to identify areas well-suited for geothermal energy, that are available and appropriate land use, and that are near such infrastructure. However, for direct heat purposes, this may be avoided if the heat uses can be accomplished near the site. Avoiding the need for transmission infrastructure also avoids potential years and millions in regulatory compliance and environmental studies to build out the power lines.

As a potential solution for process heat, another challenge and opportunity is the small market share. Currently, commercial and residential heat pumps constitute the vast majority of utilization of geothermal heating, and even heating of baths and swimming pools represents over 10 times more heat than industrial uses. Industrial uses accounts for just 0.87 percent of the worldwide capacity for geothermal.[80]

Where geothermal heat is used for industrial processes, it provides for milk pasteurization, bottling of water and carbonated drinks, pulp and paper processing, chemical extraction, iodine and salt extraction, leather industry, and boric acid production.[81] Yet many of these take place globally and not domestically. There may be industry-side recalibration and investment needed before direct process heat from geothermal is more widely utilized in the United States.

Space heating, however is a commercial and industrial application geothermal is already well-suited for. The town manager of Lakeview, Oregon, estimated that recently installed geothermal district heating for local schools and hospitals could save the school district $150,000-$200,000 per year on heating costs.[82]

Power Potential

Geothermal heat pumps already represent 90 percent of building space heating in Iceland, and the United States has seven percent annual growth of heat pumps.[83] Heat pumps appear to be best used for space heating with a relatively low steady temperature. Greenhouse heating, agricultural crop drying, and aquaculture pond heating are also effective ways to utilize geothermal energy, but industrial applications of geothermal are nascent. Space heating in the industrial and commercial setting may be the most promising.

There is compelling potential to utilize direct heat from geothermal for more process heat applications, including heavy industry. With decarbonization as the goal, one way to diminish the level of hydrocarbons used is to lower the temperature differential they are needed to fill. In other words, by preheating water or gas through geothermal – even to relatively lower "high temperatures" <300 degrees°F – it is possible to lower the carbon intensity of industry even without replacing hydrocarbons.

Geothermal has great power potential due to the natural heat within the earth, but the power potential varies by depth, which may also implicate feasibility.[84]

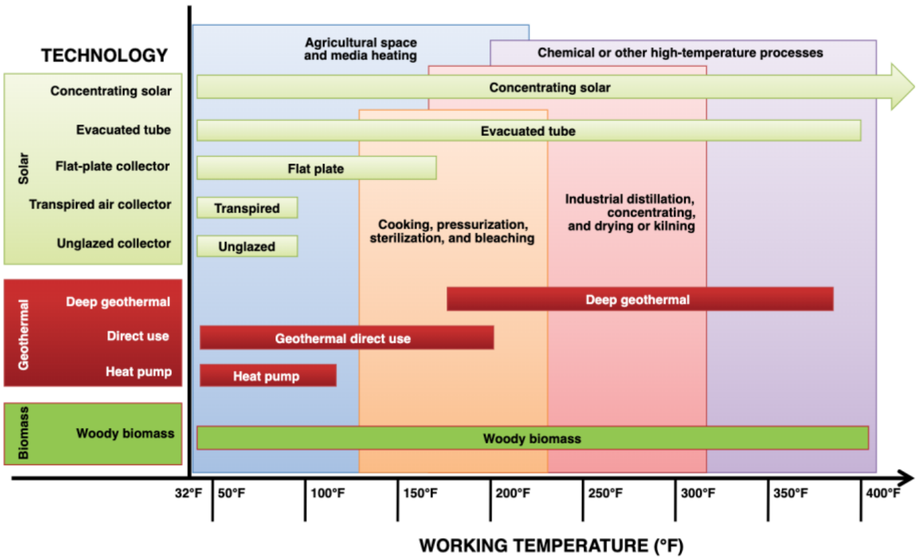


Figure 4: Temperatures and Technologies for Select Process Heat Applications (U.S. EPA)

Geothermal is a small portion of the energy sector but has great potential. While representing only 0.4 percent of utility-scale electricity in the United States, geothermal is widely relied upon for heat pumps around the country. As a renewable energy source, it can generate heat and electricity without emitting carbon dioxide but has some regional constraints.

In sum, utilizing geothermal energy directly for process heat may be a key component in a decarbonization mix. At current technology levels, geothermal heat may be best applied for preheating or liquids or gases used in heavy industry or for lower heat needed to cure or dry products. Geothermal is unlikely to take a leading role in process heat, but can aid in decarbonizing by displacing some marginal amount of hydrocarbon use or by lowering the demand for other renewables. The infrastructure needed to facilitate this solution is unclear, but may require new pipelines, although it is also possible that geothermal facilities may need to be built/drilled near to industrial centers if geologic conditions allow.

Direct heat from concentrated solar.
While this is a proven technique for generating heat, it has primarily been utilized for electricity generation, although it has only provided 0.1 percent of utility-scale electricity to the grid (3 billion kWh) in 2022. The technique has both limitations and promise in process heat applications.[85] Depending on the technology and fluids used, concentrated solar power can provide sustained heat at temperatures sufficient for virtually all process heat applications.[86] While research and analysis shows promise, more work is yet to be done to lower costs, improve designs, and present a feasible model for utilizing concentrated solar power at scale for process heat applications.[87]

Electrification

Renewables can provide heat in two ways, first by electrifying the heat sector. That would mean generating so much electricity that this power can be supercharged into forges and related equipment – not totally dissimilar to electric stove tops, water heaters, or ovens. At an industrial scale, the temperatures must be higher and reliability must be ensured. Renewables can also use their electricity in a second way, to facilitate the production of other energy resources, such as green hydrogen.

Electricity from geothermal, hydropower, nuclear, solar, and wind
This set of renewable technology and ultra-low carbon power sources harness natural and renewable forces to generate electricity. Even within this set are a diversity of technical approaches. For instance, geothermal, hydropower, nuclear, and wind all spin a turbine to generate power, while solar converts solar radiation into electricity directly.

Cost
Many factors go into the cost of a given energy resource, including the scale of production. Renewables have proven to be cost effective and competitive in certain markets. Hydrocarbons have a distinct advantage today in that they are commodity based, so generating energy is a function of transporting more fuel to power plants. By contrast, most renewables are technology based and collect or harness natural energy, but these require infrastructure investments and buildouts to do so (whereas the hydrocarbon economy already has robust supply chains, transportation networks, and infrastructure to continue supporting use of coal, oil, and natural gas). This will require considerable upfront investment to generate new energy through yet to be built renewable projects.

In rough order from least cost-effective to most, the average (global) levelized cost of electricity are: onshore wind ($0.03/kWh), hydropower ($0.05/kWh), photovoltaic solar ($0.05/kWh), geothermal ($0.07/kWh), offshore wind ($0.08/kWh), and concentrated solar power ($0.11/kWh).[88] In some cases, the price is higher by around one to four cents[89] per kWh in the U.S. due to environmental regulations, labor costs, and other factors. For comparison, the average levelized cost of natural gas is approximately $0.05/kWh.

Some of those prices are expected to fall based on new projects and innovation.[90] In addition, the advent of new small modular reactors may play a key role in expanding availability and cost-effectiveness of nuclear. These levelized costs can also be influenced by tax credits and other incentives or subsidies. The low cost of natural gas in the U.S. is the main barrier for much of the technology being adopted. It is simply more economical for companies to use natural gas. This also gives an advantage to decarbonization projects that leverage existing infrastructure rather than buildout new infrastructure.

Along the lines of infrastructure buildouts, a considerable mileage of new transmission lines will be needed in order to effectively decarbonize. Policymakers should consider these costs as well, which may not be captured when looking solely at the price point of proposed renewable energy. Likewise, more efficient power transmission may lower prices.

> Total transmission capacity (which is a mix of AC and HVDC depending on scenario) in 2035 is 1.3–2.9 times current capacity. Beyond already planned additions, these total transmission builds would require 1,400– 10,100 miles of new high-capacity lines per year, assuming new construction began in 2026.[91]

The capital cost of a new 500kV transmission line was found to be $3.898M/mile by one recent study.[92,93] Longer and more rigorous regulatory and permitting compliance can increase this as well.

Environmental Impact

Each type of renewable or low-carbon power source has its own environmental footprint. From lifecycle emissions to land use to waste disposal, none is without a mark on the environment.

Discussed elsewhere in this paper, renewables rely on mining. To build out an electrified economy – or even simply an electrified process heat sector – will take a significant increase in mining and processing of raw materials, transportation across international supply chains, and ultimately manufacturing and construction to install the infrastructure. Lifecycle emissions captures the greenhouse gas impact from these sources, including their development and retirement.

In rough order from least carbon-intensive to most, the median lifecycle emissions are: nuclear (13g CO2e/kWh), wind, (13g CO2e/kWh), hydropower (21g CO2e/kWh), concentrated solar power (28 g CO2e/kWh), geothermal (37 g CO2e/kWh), and photovoltaic solar power (43 g CO_2e/kWh).[94] For comparison, natural gas has a median lifecycle emission rate of 486g CO_2e/kWh without any carbon capture technology, and that is by far the lowest emission rate among hydrocarbons.

While that metric captures emissions, many other environmental impacts accrue alongside each step in the process. Mining can cause local ecological disruptions and disturb groundwater, there are public health effects due to safety and respiratory risks that go along with mining.

Part of the regulatory process discussed below is to evaluate the totality of the impact to the environment from start to installation of an infrastructure project. This includes determining the effect on the ecosystem, water resources, wildlife, and more. Some of the relevant impacts include: large land footprint taking up land and precluding any alternative use, high water usage, leaching chemicals or other substances into the ground, generating industrial waste that is difficult to recycle, disturbing wildlife habitat, increasing risk to animal safety, and disrupting migration patterns or animal behavior. While no single renewable infrastructure has each of these challenges, these exist across them all.

In particular, wind and solar may require extensive acreage, which may require deforestation of a specific site. Nuclear currently requires considerable water resources and results in radioactive waste with no national strategy to store permanently. Hydropower and offshore wind can disrupt aquatic life. Geothermal drilling could be linked to small-scale seismic activity. Many of these same concerns are also relevant to power storage and to transmission infrastructure, which may mean compounding certain negative impacts by installing new renewable infrastructure, storage, and transmission lines in a specific region.

These technologies and infrastructure also come with positive environmental impacts, like displacing or preventing new emissions. This is linked to the greenhouse effect, but also to public health and respiratory health when accounting for particulate matter and other emissions. They also produce power more directly and do not require fuel or commodities to run (except for nuclear). This lessens the risk of leaks or spills of hazardous material like oil and gas, while also limiting the vehicle and transportation emissions to bring energy resources to consumers.

Regulatory and Permitting Compliance

There are a great number of permitting hurdles for nuclear, wind, solar, and hydropower in themselves. Added permitting and regulatory issues arises when factoring in the need to build new transmission infrastructure to facilitate them. Among the compliance regimes are NEPA, as well as directives and rules from local, state, federal, and tribal authorities, which may factor in both private and public perspectives.

Further up the supply chain are the raw materials needed even to build the renewable infrastructure in question. This includes mining for minerals and metals needed to wind technology, solar panels, batteries, and more. While this is partially a supply chain risk to be factored into logistical feasibility, there are regulatory barriers that implicate it:

> A new report from the Biden administration recommends overhauling an 1872 mining law. The report calls on Congress to update the General Mining Act of 1872, asks federal agencies to streamline regulations between departments and suggests mining companies need to meet with the federal government before filing for permits in order to speed up mining projects that are essential for the country's transition to cleaner energy.[95]

Two recent infrastructure projects illustrate the regulatory requirements to see new energy infrastructure approved and built. These each took many years to receive approval, due to back and forth with landowners, multiple levels of government, and rigorous requirements in regulation relating to the extent of environmental and economic studies.

The Gemini Solar Project in Nevada was initially proposed in 2008 by BrightSource Energy but certain application paperwork was not completed.[96] By 2017, the project was acquired by Solar Partners XI, which cut the acreage and generating capacity in half and submitted the full paperwork. The eventual approval took another two years and was only possible because of the Fixing America's Surface Transportation Act (FAST Act or FAST-41 after Title 41). Three years of construction brings the project to completion this year, 15 years after its ideation and six years after filing through an expedited permitting process.

In another instance, an offshore wind farm required 12 years of behind the scenes permitting and compliance before construction began.[97] The South Fork Wind project finally started construction in 2022, but the 12 preceding years were all used to gear up for it. From deconflicting ocean uses to assessing how a wind farm would affect local commerce and the environment, the governors of Rhode Island and Massachusetts collaborated to set the stage for this project. This illustrates how many overlapping and intersecting issues may appear that threaten the feasibility of a project or result in substantial delays or reworking of the plan.

Timing Readiness

Many renewable energy technologies have been producing power for decades. However, even today they are a small proportion of total energy. Taken together, renewables make up approximately the same share of the U.S. electricity mix as coal. To switch all process heat to electricity now would require that demand increase by an equivalent amount – far out pacing the capacity of renewables and hydrocarbons combined with our current power production and electrical grid capabilities. This solution would be two decades away at a bare minimum – and even then each solution would have its own timeline issues, compounded by the growth in the grid itself. Even if these took place concurrently, it is likely 20 years away.

Compliance with NEPA takes an average of around 6 years. Project delays, cost overruns, and activism can add years even past that point. Add to this that the generating infrastructure itself must be connected to new transmission infrastructure – with its own NEPA compliance – and the process can easily extend past a decade, even when elements are pursued concurrently.

In the case of one transmission line in recent years, the NEPA process alone took 15 years.[98] All that time, renewable power could not be transmitted from the point of origin to the destination by via that route. The SunZia Southwest Transmission Project did not start construction until September 2023, yet its first applications were submitted exactly 15 years before, in September 2008. The route was scrutinized for its potential to obstruct military test flights, leading to engagement by the Department of Defense, Department of the Interior, the Bureau of Land Management, and others. This process demonstrates that new infrastructure can be incredibly difficult to build and involve long timelines. These ultimately delay the connection of renewable electricity to end users and inhibit growth.

After 15 full years, there must still be a construction phase, delaying the transmission of power even further. While this is a unique set of circumstances, the state of permitting for large infrastructure can truly be a decades-long process. The same timing for regulatory approvals, land acquisition, and readiness for construction apply to both power generation and transmission, making concurrent expansion the only way to shorten the timeline.

When it comes to the equipment needed on the industrial end, dozens of electrification processes are in development or already commercialized across process heating, but industrial-scale and economy-wide electrification is many years of development out. There have been significant developments in electrification of cement kilns and the pulp and paper process, but more time is needed.[99] Ultimately, the timing readiness to electrify the process heat sector is less dependent on industry-side factors and more on the national regulatory process and state of infrastructure.

Logistical Feasibility

The deployment and expansion of renewable technology and nuclear alongside a more robust energy grid with new transmission lines is feasible. The logistics of doing so with the goal of decarbonization presents challenges due to the inherent material- and energy-intensity of each of those goals, and the current regulatory environment and international supply chains makes doing so quickly virtually impossible.

The most relevant factors have been discussed above and they include access to raw materials and mining, supply chain risk and price fluctuation, the scale of generating capacity needed to ramp up, and new infrastructure needed to facilitate the transmission of power.

Raw material access may be partially resolved through domestic mining, reforms for which may be on the horizon. However, the quantity of rare earth metals and other precious resources needed to satisfy domestic and global demand for renewable technologies, industrial scale batteries, and electric vehicles is not realistic. To meet all of these complementary (but competing for resources) goals would require more mining than global supply can satisfy. In some cases, there may simply be more demand than can be met.

> Global demand for neodymium is expected to grow 48 percent by 2050, exceeding the projected supply by 250 percent by 2030. The need for praseodymium could exceed supply by 175 percent. Terbium demand is also expected to exceed supply. And to meet the anticipated demand by 2035 for graphite, lithium, nickel, and cobalt, one analysis projected that 384 new mines would be needed.[100]

One solution is innovation to build systems less reliant on these particular minerals and metals. Another solution is more robust and efficient material recycling. In either case, there are legitimate feasibility challenges to overcome making simply the material acquisition a potentially decades-long project.

With materials on hand, there are inherent challenges to regulatory approval before construction can begin. Among these are land acquisition and engagement with local and state communities and authorities. Some solar experts have even explained that while land acquisition for utility-scale solar is a challenge, it is a greater challenge to receive permitting.[101] Another land-related challenge is location. Hydropower and geothermal are regionally constrained sources of energy, narrowing the potential locations to implement them and also increasing the likelihood of a land use or environmental challenge. These geographic limitations exist for wind and solar to a lesser degree.

All of the logistical factors have been overcome by those renewable plants and farms already in place. It is proven that renewables can be built and expanded, but the scale of expansion is a challenge.

Transitioning to electrification of process heating would require magnitudes more electricity. In 2018, process heating used 7,576 trillion BTUs of energy, only 297 TBtu of which came directly from electricity (3.9 percent).[102] To replace all of the remaining fuel and steam powered energy with electricity would require over 2,000 TWh, about half the total U.S. electricity production (of which only 21 percent is currently supplied by renewables[103]). Obviously, it is impractical to replace all processes with electrotechnology, but electrification will still require a massive increase in affordable, renewable energy. To facilitate this electrification with renewables would require a threefold increase in renewable output – over a 200 percent increase from what renewables currently produce. In other words, tripling the existing level of renewables across the entire country.

> "…new renewable energy capacities that are coming up across the world will serve little purpose without the power transmission grids to connect the green energy produced in renewable rich areas to the renewable deficit corners of the country." [World Economic Forum]

Along with the need to expand capacity and output from the low-carbon and renewable sector come accompanying challenges like the need for supporting infrastructure. It is projected that the U.S. needs to expand its electrical grid by as much as 60 percent, adding 400,000 miles or more of new transmission lines over the next decade. These are needed to bring the power from potentially remote, rural, or offshore power sources to the grid and to commercial and industrial sectors. These projects too must be reviewed through each of the six factors assessed here, including land use, cost, and regulatory approvals.

A transmission project started in 2015 took over 8 years to see its application approved due largely to compliance with NEPA and coordinating logistics, even though it was a FAST-41 project.[104] The Ten West link project also plans to connect renewable power to end users, but throughout the permitting process, had to conduct repeated analysis of stakeholder concerns and regional community perspectives. Construction began this year, so power is not yet flowing.

The unforeseen risks that can arise may best be demonstrated with the Vineyard Offshore Wind farm.[105] Evaluations began in 2009, over 14 years ago. It was not until 2017 that the site sale and assessment was completed. In the ensuing six years, there have been issues with environmental studies and permits. Most recently, activist lawsuits have halted construction of the offshore power generating infrastructure.

The main issue with logistical feasibility is permitting and the extent of supporting infrastructure needed to support the electrification of the process heat sector. Not only do electric components need to be installed – in some cases completely overhauling a process heat facility – but the power has to come from somewhere. That new renewable power would require land acquisition, permitting, environmental studies, and a host of other compliance hurdles.

As a final consideration, while considering the expansion of renewable power generation, policymakers cannot forget the need to maintain and replace existing generation when it ends its useful life. The relatively shorter lifespan of renewable technology[106] against hydrocarbon facilities, nuclear, and hydropower present a challenge of maintaining the stock of energy infrastructure while simultaneously expanding it.

Lifetimes

The EGC harmonised expected lifetimes for each technology across countries are as follows through consensus:

Battery storage:	10 years
Solar PV, onshore and offshore wind:	25 years
Gas-fired power plants:	30 years
Coal-fired power and geothermal plants:	40 years
Nuclear power plants:	60 years
Hydropower plants:	80 years
Additional lifetime after nuclear LTO:	10 or 20 years, depending on regulatory framework

Figure 5: Energy Infrastructure Lifespan (International Energy Agency, Nuclear Energy Agency)

The question is not whether the logistics can be managed, and the deployment of renewables is feasible, but whether more than doubling renewable generating capacity and nuclear power as well as transmission infrastructure to meet political goals on a compressed timeline is feasible. Because of how many contingent factors exist, the answer – unless or until changes are made to regulation and supply chain access – is that the largescale increase in renewables must take place at a deliberate pace over decades, not immediately. These are dictated by current realities and tradeoffs, not preference.

Power Potential

In many cases, electrical heating systems are more energy efficient than fuel-based ones.[107] Electricity can provide high and sustained temperatures so long as it is continuously supplied by reliable generation. It is already used for fluid heating, drying, metal heat treating, smelting, metal melting, non-metal melting, and cutting and forming, along with other applications.[108]

The only way electrification of process heating can be effective at decarbonization is if the energy it's using is coming from clean sources. This will mean not only a massive increase in electricity production, but also that the electricity must come from low-CO_2 emission sources, namely solar, wind, and nuclear. Because wind and solar can be intermittent, there needs to be constant baseload and dispatchable power to electrify process heat. If storage can solve this, it may add another component in need of running all six factors again to analyze it.

Electrification has already been used substantially in industrial and commercial uses, including process heat. To date, much of that electricity is ultimately derived from hydrocarbons on the grid. To pursue decarbonization through electrification requires both that the power come from renewables or low-carbon sources like hydrogen and nuclear, but also that this power be scaled up considerably to replace existing process heat from hydrocarbons.

In sum, electrification of process heat is the ultimate goal for many seeking to decarbonize the entire economy. Because it has received so much attention and has so many advocates, there is great need to assess the entire scale and scope of the task. While renewables can be scaled up, they will require considerable increases in raw materials and mining as well as supporting infrastructure to connect them to industrial facilities. Permitting reform is needed to streamline the timing (and implicitly the cost) of such an infrastructure buildout, not only for the generating capacity but for transmission lines and grid improvements.

Beginning the Transition

While this paper has explored decarbonizing for commercial and industrial process heat, this framework is also applicable to decarbonizing the electricity sector as well as transportation. It can be employed for other large-scale infrastructure projects as well. Public policy changes – including subsidies and penalties – must account for more than a simple cost-benefit analysis or cursory view of the impacts.

Ultimately, there must be comprehensive and *cumulative cost-benefit analyses* that not only evaluate a given strategy (e.g., new capacity from energy/heat installation) but also the new infrastructure needed to facilitate it (e.g., transmission lines, pipelines, storage) and the time, permitting, and net impact of that sub-project. Without these factors accounted for, there will be inefficiencies at best and outright harm at worst looming for individuals, communities, businesses, and the wider economy and nation.

In depth cost-benefit analyses and environmental studies within the current scheme already account for many of the factors presented here. But one party is often only responsible for one element – the builder for a solar farm is not often the builder for the transmission lines, the hydrogen producer is not the pipeline builder or operator. As a framework for understanding the cumulative impact, this approach gives policymakers the wider perspective to see that subsidizing or approving one project may necessitate approving another – or that potential positive results from one will not come to fruition until other improvements are made.

Strategies that leverage existing infrastructure are not preferrable simply because they require less investment and save money. They are preferred because they have long ago internalized many of the costs likely to be accrued before any new solution becomes feasible. They do not produce significant new emissions to build out the necessary (new) infrastructure, they do not require extensive permitting and delays, and they can offer results immediately rather than a decade away.

Before any significant transition away from the status quo is warranted or advisable, all reasonable efforts should be made to utilize existing infrastructure and to conduct both comprehensive and cumulative analyses of any new strategy. Policymakers should also be wary of strategies that seek to turn negative aspects into positives. One such point would be high costs and new infrastructure needed being hailed as job creation. This is a difficult web to untangle, but clear analysis of the issue may reveal that preferable alternatives exist that leverage existing infrastructure or do not require new buildouts.

The highly-sought-after goal of “net zero” and a decarbonized economy can begin now, with a transition that looks more like reform than rebuilding.

Conclusion

The U.S. transmission infrastructure needs to expand by 60 percent by 2030 and adding over 400,000 miles of new infrastructure to meet ultimate net zero goals. The average timeline for such a project is 10 to 12 years, while new pipelines often take as many as seven to nine years. The cost and delays of regulatory compliance and permitting are extensive. Per mile, new transmission lines may cost over $2 million, while a mile of pipeline can run an average of over $8 million.

Even with reforms, the comprehensive nature of a full-scale decarbonization effort will mean legal challenges at every level, logistical challenges, cost overruns, land use issues, environmental impacts, and more. The most effective strategy is the one that leverages existing infrastructure to the greatest extent possible, then has the most net beneficial path through the remaining hurdles.

The framework presented here is intended to equip industry leaders and policymakers with a better understanding of the merits and challenges of certain proposed decarbonization goals. A strategy that can avoid new buildouts, is insulated from price volatility and supply chain risk, does not add demand to the grid, and has little or no environmental impact – besides a proven ability to decarbonize – should be prioritized. Instead, we often see or hear that a narrow set of renewable power sources are the priority technologies. While they do have competitive benefits, they are substantial infrastructure projects that are energy- and material-intensive in their own right.

In thinking through this framework, policymakers should also note the considerable difference in centralized and distributed processes. These will require different levels of infrastructure and entirely different economies of scale.

Citations and Notes

[1] Toledano, I. (2016). *Process Heating for Manufacturing 101*. Processing Magazine. https://www.processingmagazine.com/process-control-automation/heating-cooling/article/15586674/process-heating-for-manufacturing-101.

[2] IEA. (2023). *Towards hydrogen definitions based on their emissions intensity.* IEA. https://energycentral.com/system/files/ece/nodes/603831/towardshydrogendefinitionsbasedontheiremissionsintensity.pdf.

[3] Industry call.

[4] *Id*.

[5] This is dependent on the method, but also the market for carbon. Certain methods of methane pyrolysis are cost competitive with SMR on their own, while the sale of carbon black can also bring the net cost into closer parity.

[6] Patlolla, S. R., Katsu, K., Sharafian, A., Wei, K., Herrera, O. E., & Mérida, W. (2023). *A review of Methane Pyrolysis technologies for hydrogen production*, Renewable and Sustainable Energy Reviews. https://www.sciencedirect.com/science/article/abs/pii/S136403212300179X.

[7] Sánchez-Bastardo, N., Schlögl, R., & Ruland, H. (2021). *Methane pyrolysis for zero-emission hydrogen production: A potential bridge technology from fossil fuels to a renewable and sustainable hydrogen economy*. Industrial & Engineering Chemistry Research, *60*(32), 11855–11881. https://doi.org/10.1021/acs.iecr.1c01679.

[8] Advanced Energy Technologies. (2022). *Direct Conversion of Methane to Hydrogen by Pyrolysis: Status and Prospects*. Advanced Energy Technologies. https://aenert.com/news-events/energy-news-monitoring/n/direct-conversion-of-methane-to-hydrogen-by-pyrolysis-status-and-prospects/.

[9] Parkinson, Brett, Matthews, Joshua W., McConnaughy, Thomas B., Upham, D. Chester, & McFarland, Eric W. (2017). *Techno-Economic Analysis of Methane Pyrolysis in Molten Metals: Decarbonizing Natural Gas*. Chem. Eng. Technol., 40: 1022-1030. https://doi.org/10.1002/ceat.201600414.

[10] Thunder Said Energy. (2019). *Hydrogen: Overview and Conclusions*. Thunder Said Energy. https://thundersaidenergy.com/downloads/hydrogen-overview-and-conclusions/.

[11] *Supra* note 8.

[12] DOE. (2023). *U.S. National Clean Hydrogen Strategy and Roadmap*, Department of Energy. https://www.hydrogen.energy.gov/pdfs/us-national-clean-hydrogen-strategy-roadmap.pdf.

[13] IEA. (2019). *The Future of Hydrogen*. IEA. https://www.iea.org/reports/the-future-of-hydrogen.

[14] Dierker, B. (2023). *How Soon Can Hydrogen Help Decarbonize*. Alliance for Innovation and Infrastructure. https://www.aii.org/how-soon-can-hydrogen-help-decarbonize/.

[15] McMurray, T. (2023). *Decarbonizing Natural Gas*. Gas Technology Magazine. Energysolutioncenter.org.

[16] Assuming U.S. average gas and a truck mileage of 400 miles. Sources including *Tavarani et al. Diab et al. Modern Hydrogen*.

[17] Myers, M. (2018). *On-Site Hydrogen Production via Distributed Methane Pyrolysis*. Massachusetts Institute of Technology. https://dspace.mit.edu/bitstream/handle/1721.1/151490/myers-madisonm-mba-mgt-2023-thesis%5b76%5d.pdf?sequence=1&isAllowed=y.

[18] *Supra* note 12.

[19] *Supra* note 9.

[20] Koestner, J. (2021). *6 Things to Remember about Hydrogen vs Natural Gas*. Power Engineers. https://www.powereng.com/library/6-things-to-remember-about-hydrogen-vs-natural-gas.

[21] Helmenstine, Anne Marie, Ph.D. (2020, August 27). Flame Temperatures Table for Different Fuels. Retrieved from https://www.thoughtco.com/flame-temperatures-table-607307.

[22] Thermal Fluids Central. (2011). *Heat of Combustion*. Thermal Fluids Central. https://www.thermalfluidscentral.org/encyclopedia/index.php/Heat_of_Combustion.

[23] EIA. (2023). *Use of Energy Explained*. U.S. Energy Information Administration. https://www.eia.gov/energyexplained/use-of-energy/industry.php.

[24] *Supra* note 2.
[25] Ramirez, K., Weiss, T., Kirk, T. (2023). *Hydrogen Reality Check: Distilling Green Hydrogen's Water Consumption*. RMI. https://rmi.org/hydrogen-reality-check-distilling-green-hydrogens-water-consumption/.
[26] Vickers, J., Peterson, D., Randolph, K. (2020) *DOE Hydrogen and Fuel Cells Program Record*. DOE. https://www.hydrogen.energy.gov/pdfs/20004-cost-electrolytic-hydrogen-production.pdf.
[27] DOE. (2023). *Pathways to Commercial Liftoff: Clean Hydrogen*. U.S. Department of Energy. https://liftoff.energy.gov/wp-content/uploads/2023/05/20230320-Liftoff-Clean-H2-vPUB-0329-update.pdf.
[28] *Id*.
[29] Bolinger, M., Wiser, R., & O'Shaughnessy, E. (2022). *Levelized cost-based learning analysis of utility-scale wind and solar in the United States*. iScience, *25*(6), 104378. https://doi.org/10.1016/j.isci.2022.10437.
[30] IEA. (2019). *Nuclear Power in a Clean Energy System*. IEA. https://www.iea.org/reports/nuclear-power-in-a-clean-energy-system.
[31] *Id*.
[32] *Supra* note 7.
[33] IEA. (2021). *Share of clean energy technologies in total demand for selected minerals by scenario, 2010-2040*. IEA. https://www.iea.org/data-and-statistics/charts/share-of-clean-energy-technologies-in-total-demand-for-selected-minerals-by-scenario-2010-2040.
[34] IEA. (2021). *The Role of Critical Minerals in Clean Energy Transitions*. IEA. https://www.iea.org/reports/the-role-of-critical-minerals-in-clean-energy-transitions.
[35] DOE. (2022). *Water Electrolyzers and Fuel Cells Supply Chain*. U.S. Department of Energy. https://www.energy.gov/sites/default/files/2022-02/Fuel%20Cells%20%26%20Electrolyzers%20Supply%20Chain%20Report%20-%20Final.pdf.
[36] Goligorsky, S., Lin, E., Mues, A., Rooke, H., Walker, N., Alhassan, K., Cheung, N., Hussain, T., Sabur, Z., Burkhart, I.(2022). *Hydrogen Regulations by Jurisdiction and Changing Transmission Systems*. ReedSmith. https://www.reedsmith.com/en/perspectives/energy-transition/2022/06/hydrogen-regulations-by-jurisdiction-and-changing-transmission-systems.
[37] PHMSA. (2022). *Phases of Pipeline Construction: An Overview*. U.S. Department of Transportation. https://www.phmsa.dot.gov/pipeline/pipeline-construction/phases-pipeline-construction-overview.
[38] Although there is potential debate over which agency has primary authority and greater legal and regulatory clarity is called for.
[39] Diamond, M. (2022*) Jurisdiction Over Hydrogen Pipelines and Pathways to an Effective Regulatory Regime*. Van Ness Feldman LLP. https://www.vnf.com/Hydrogen-Pipelines.
[40] Gielen, D., Lathwal, P., Rocha, S.C. (2023), *Unleashing the Power of Hydrogen for the Clean Energy Transition*. World Bank. https://blogs.worldbank.org/energy/unleashing-power-hydrogen-clean-energy-transition.
[41] Dierker, B. (2023) *One Reason for Rising Energy Costs*. Alliance for Innovation and Infrastructure. https://www.aii.org/one-reason-for-rising-energy-costs/.
[42] DOE. (2023). *Pathways to Commercial Liftoff: Clean Hydrogen*. U.S. Department of Energy. https://liftoff.energy.gov/wp-content/uploads/2023/05/20230320-Liftoff-Clean-H2-vPUB-0329-update.pdf.
[43] EIA. (2023). *Nuclear Explained*. U.S. Energy Information Administration. https://www.eia.gov/energyexplained/nuclear/nuclear-power-plants.php.
[44] Dura, J. (2023). *South Dakota panel denies application for CO2 pipeline*; Summit to refile for permit. AP News. https://apnews.com/article/south-dakota-north-dakota-co2-pipeline-summit-827c7418edba5a4ecbd7501be02d84f9?utm_source=briefing&utm_medium=email&utm_campaign=energy_am&utm_content=091223.
[45] Smith, C. (2022). *Pipelines materials' costs increases lift overall construction price*. Oil and Gas Journal. https://www.ogj.com/pipelines-transportation/pipelines/article/14283934/pipeline-materials-cost-increases-lift-overall-construction-price.
[46] PHMSA. (2022). *Phases of Pipeline Construction: An Overview*. U.S. Department of Transportation. https://www.phmsa.dot.gov/pipeline/pipeline-construction/phases-pipeline-construction-overview.

[47] Koestner, J. (2021). *6 Things to Remember about Hydrogen vs Natural Gas*. Power Engineers. https://www.powereng.com/library/6-things-to-remember-about-hydrogen-vs-natural-gas.
[48] Helmenstine, Anne Marie, Ph.D. (2020, August 27). Flame Temperatures Table for Different Fuels. Retrieved from https://www.thoughtco.com/flame-temperatures-table-607307.
[49] Thermal Fluids Central. (2011). *Heat of Combustion*. Thermal Fluids Central. https://www.thermalfluidscentral.org/encyclopedia/index.php/Heat_of_Combustion.
[50] This is not calculated in "utility-scale electricity generation" and therefore it is surplus to it. The percentage is based on utility-scale generation. Distributed solar, generated around 58 billion kWh.
[51] Barnert, H., Krett, V., Kupitz J. (1991) *Nuclear Energy for Heat Applications*. International Atomic Energy Agency. https://www.iaea.org/sites/default/files/publications/magazines/bulletin/bull33-1/33104782124.pdf.
[52] W.R. Stewart, E. Velez-Lopez, R. Wiser, K. Shirvan, Economic solution for low carbon process heat: A horizontal, compact high temperature gas reactor, Applied Energy, Volume 304, 2021, 117650, ISSN 0306-2619, https://doi.org/10.1016/j.apenergy.2021.117650. (https://www.sciencedirect.com/science/article/pii/S0306261921010175).
[53] Saied Dardour, Henri Safa. (2017). *Energetic and economic cost of nuclear heat − impact on the cost of desalination*, EPJ Nuclear Sci. Technol. 3, 1. https://doi.org/10.1051/epjn/2016037.
[54] Hogue, M. (2012). *A Review of the Costs of Nuclear Power Generation*. Utah Economics and Business Review. https://gardner.utah.edu/Documents/uebr/UEBR2012/UEBR2012no1.pdf.
[55] Lenzen, M. (2008). *Life Cycle Energy and greenhouse gas emissions of nuclear energy: A Review*. Energy Conversion and Management, *49*(8), 2178–2199. https://doi.org/10.1016/j.enconman.2008.01.033.
[56] Lee, W.-J., Kim, Y.-W., & Chang, J.-H. (2009). *Perspectives of nuclear heat and hydrogen*. Nuclear Engineering and Technology, *41*(4), 413–426. https://doi.org/10.5516/net.2009.41.4.413.
[57] Ritchie, H. (2022). *How does the land use of different energy sources compare*. Our World in Data. https://ourworldindata.org/land-use-per-energy-source.
[58] National Academies Press. (2023). Nuclear Regulations in the United States. In *Laying the foundation for new and advanced nuclear reactors in the United States* (pp. 137–154). National Academies of Sciences, Engineering, and Medicine. https://doi.org/10.17226/26630.
[59] Rising, A. (2017). *Barriers to nuclear generation must be removed to take action on climate change*. World Nuclear Association. https://www.world-nuclear.org/press/press-statements/barriers-to-nuclear-generation-must-be-removed.aspx.
[60] World Nuclear Association. (2021). *Nuclear Process Heat for Industry*. World Nuclear Association. https://world-nuclear.org/information-library/non-power-nuclear-applications/industry/nuclear-process-heat-for-industry.aspx.
[61] NEA. (2022). *High-temperature Gas-cooled Reactors and Industrial Heat Applications*. Nuclear Energy Agency. https://www.oecd-nea.org/upload/docs/application/pdf/2022-06/7629_htgr.pdf.
[62] Ritchie, H. (2023). *How long does it take to build a nuclear reactor?* Sustainability by Numbers. https://www.sustainabilitybynumbers.com/p/nuclear-construction-time.
[63] NEA. (2022). *High-temperature Gas-cooled Reactors and Industrial Heat Applications*. Nuclear Energy Agency. https://www.oecd-nea.org/upload/docs/application/pdf/2022-06/7629_htgr.pdf.
[64] Powers, M., Rubin, D. (2023). *US Must Tackle Barriers Now to Advanced Nuclear Construction*. Engineering News-Record. https://www.enr.com/articles/56374-us-must-tackle-barriers-now-to-advanced-nuclear-construction.
[65] Barnert, H., Krett, V., Kupitz J. (1991) *Nuclear Energy for Heat Applications*. International Atomic Energy Agency. https://www.iaea.org/sites/default/files/publications/magazines/bulletin/bull33-1/33104782124.pdf.
[66] World Nuclear Association. (2021). *Nuclear Process Heat for Industry*. World Nuclear Association. https://world-nuclear.org/information-library/non-power-nuclear-applications/industry/nuclear-process-heat-for-industry.aspx.
[67] *Supra* note 63.
[68] Fisher, M., Constantin, A., Liou, J. (2021). *The Use of Nuclear Power Beyond Generating Electricity: Non-Electric Applications*. International Atomic Energy Agency. https://www.iaea.org/newscenter/news/the-use-of-nuclear-power-beyond-generating-electricity-non-electric-applications.

[69] Self, S. J., Reddy, B. V., & Rosen, M. A. (2013). *Geothermal Heat Pump Systems: Status Review and comparison with other heating options*. *Applied Energy*, *101*, 341–348. https://doi.org/10.1016/j.apenergy.2012.01.048.
[70] Eberle, A., Heath, G., Nicholson S., Carpenter, A. (2017). *Systematic Review of Life Cycle Greenhouse Gas Emissions from Geothermal Electricity*. U.S. National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy17osti/68474.pdf.
[71] NREL (2021). *Life Cycle Greenhouse Gas Emissions from Electricity Generation: Update*. U.S. National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy21osti/80580.pdf.
[72] Aii. (2023). *What is Geothermal Energy? | Aii Energy Month*. Youtube. Alliance for Innovation and Infrastructure. https://www.youtube.com/watch?v=O5j7nzgr2xM.
[73] Geothermal Technologies Office. (2023). *Geothermal FAQs*. U.S. Department of Energy. https://www.energy.gov/eere/geothermal/geothermal-faqs.
[74] Downy, H. (2022). *Regulatory Barriers to Geothermal Energy*. Property and Environment Research Center. https://www.perc.org/2022/01/25/regulatory-barriers-to-geothermal-energy/.
[75] Nelson, S. (2019). *Regulatory Reform Could Unlock Gigawatts of Zero-Emission Geothermal*. Clear Path. https://clearpath.org/tech-101/regulatory-reform-could-unlock-gigawatts-of-zero-emission-geothermal/.
[76] Young, K., Levine, A., Cook, J., Heimiller, D., Ho, J. (2019). *GeoVision Analysis Supporting Task Force Report: Barriers*. U.S. National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy19osti/71641.pdf.
[77] *Supra* note 74.
[78] *Supra* note 61.
[79] Geothermal Technologies Office. (2023). *Geothermal FAQs*. U.S. Department of Energy. https://www.energy.gov/eere/geothermal/geothermal-faqs.
[80] Lund, J. W., & Boyd, T. L. (2016*). Direct utilization of Geothermal Energy 2015 Worldwide Review*. Geothermic**s**, *60*, 66–93. https://doi.org/10.1016/j.geothermics.2015.11.004.
[81] *Id*.
[82] Rees, J. (2015) *Clean Geothermal Heating in Lakeview, Oregon, Community Buildings is Keeping Energy Costs Low as the Temperature Drops*. U.S. Department of Agriculture Rural Development. https://www.rd.usda.gov/newsroom/news-release/clean-geothermal-heating-lakeview-oregon-community-buildings-keeping-energy.
[83] *Supra* note 80.
[84] EPA. (2023). *Renewable Industrial Process Heat*. U.S. Environmental Protection Agency. https://www.epa.gov/rhc/renewable-industrial-process-heat.
[85] ‘Gus’ Nathan, G., Lee, L., Ingenhoven, P., Tian, Z., Sun, Z., Chinnici, A., Jafarian, M., Ashman, P., Potter, D., & Saw, W. (2023). Pathways to the use of concentrated solar heat for high temperature industrial processes. Solar Compass, 5, 100036. https://doi.org/10.1016/j.solcom.2023.100036.
[86] *Supra* note 84.
[87] NREL. (2023) *Concentrated Solar Heat*. National Renewable Energy Laboratory. https://www.nrel.gov/csp/concentrated-solar-heat.html.
[88] Our World in Data. (2021). *Levelized cost of energy by Technology, World*. Our World in Data. https://ourworldindata.org/grapher/levelized-cost-of-energy?facet=none.
[89] NEA. (2020) *Levelized Cost of Electricity Calculator*. Nuclear Energy Agency. https://www.oecd-nea.org/lcoe/.
[90] EIA, (2022). *Levelized Costs of New Generation Resources in the Annual Energy Outlook 2022*. U.S. Energy Information Administration. https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf.
[91] Denholm, P., Brown, P., Cole, W., Mai, T., Sergi, B. (2022). *Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035*. National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy22osti/81644.pdf.
[92] DeSantis, D., James, B. D., Houchins, C., Saur, G., & Lyubovsky, M. (2021). *Cost of long-distance energy transmission by different carriers*. iScience, *24*(12), 103495. https://doi.org/10.1016/j.isci.2021.103495.
[93] Saadi, F. H., Lewis, N. S., & McFarland, E. W. (2018). *Relative costs of transporting electrical and Chemical Energy*. Energy & Environmental Science, *11*(3), 469–475. https://doi.org/10.1039/c7ee01987d.

[94] NREL (2021). *Life Cycle Greenhouse Gas Emissions from Electricity Generation: Update*. U.S. National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy21osti/80580.pdf.
[95] Puko, T. (2023). *Update needed for 1872 mining law to boost clean energy, report says*. The Washington Post. https://www.washingtonpost.com/climate-solutions/2023/09/12/mining-law-reform-critical-minerals.
[96] Boling, E., Gimre, K. (2023). *NEPA Permitting Process Crucial to Renewable Infrastructure Project Success*. Center for American Progress. https://www.americanprogress.org/article/nepa-permitting-process-crucial-to-renewable-infrastructure-project-success/.
[97] *Id*.
[98] *Id*.
[99] Office of Energy Efficiency & Renewable Energy. (2022). *Thermal Process Intensification: Transforming the Way Industry Uses Thermal Process Energy.* U.S. Department of Energy. https://www.energy.gov/sites/default/files/2022-05/TPI%20Workshop%20Report_AMO.pdf.
[100] Cho, R. (2023). *The Energy Transition Will Need More Rare Earth Elements. Can We Secure Them Sustainably?* Columbia Climate School. https://news.climate.columbia.edu/2023/04/05/the-energy-transition-will-need-more-rare-earth-elements-can-we-secure-them-sustainably/.
[101] Aii. (2023). *What is Solar Energy? | Aii Energy Month*. Youtube. Alliance for Innovation and Infrastructure. https://www.youtube.com/watch?v=gISbZeIbqRw&list=PLZ1RkcshQL_781x2slz1HTyTUzuQuHgM0&index=30
[102] Energetics. (2021). *Manufacturing Energy and Carbon Footprint*. U.S. Department of Energy, Advanced Manufacturing Office. (https://www.energy.gov/sites/default/files/2022-01/2018_mecs_all_manufacturing_energy_carbon_footprint.pdf.
[103] EIA. (2023). *What is U.S. electricity Generation by energy source?* U.S. Energy Information Administration. https://www.eia.gov/tools/faqs/faq.php?id=427&t=3.
[104] Boling, E., Gimre, K. (2023). *NEPA Permitting Process Crucial to Renewable Infrastructure Project Success*. Center for American Progress. https://www.americanprogress.org/article/nepa-permitting-process-crucial-to-renewable-infrastructure-project-success/.
[105] *Id*.
[106] IEA. (2020). *Projected Costs of Generating Electricity 2020*. IEA. https://www.iea.org/reports/projected-costs-of-generating-electricity-2020.
[107] Office of Energy Efficiency & Renewable Energy. (2022). *Thermal Process Intensification: Transforming the Way Industry Uses Thermal Process Energy.* U.S. Department of Energy. https://www.energy.gov/sites/default/files/2022-05/TPI%20Workshop%20Report_AMO.pdf.
[108] Office of Energy Efficiency & Renewable Energy. *The Big Picture on Process Heating.* U.S. Department of Energy. https://www.energy.gov/eere/amo/articles/big-picture-process-heating.

Author

Benjamin Dierker, JD, MPA
Executive Director, Alliance for Innovation and Infrastructure

For more information or inquiries on this report, please contact the Aii Media Coordinator at info@aii.org

Recommended Citation for this report

Dierker, B. (September, 2023). *Pathways to Decarbonizing Heat: Building a Holistic Framework for Evaluating and Ranking Decarbonization Strategies for Industrial Heat in Light of Economic Efficiency, Public Policy, Timing Readiness, and Infrastructure Realities*. Alliance for Innovation and Infrastructure.

About Aii

The Alliance for Innovation and Infrastructure (Aii) is an independent, national research and educational organization that explores the intersection of economics, law, and public policy in the areas of climate, damage prevention, energy, infrastructure, innovation, technology, and transportation.

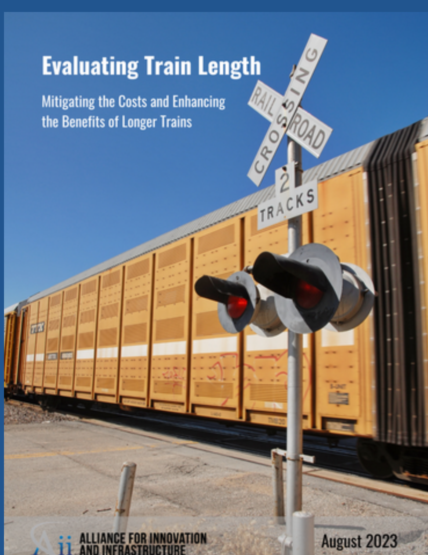
The Alliance is a think tank consisting of two non-profits: the National Infrastructure Safety Foundation (NISF), a 501(c)(4) social welfare organization, and the Public Institute for Facility Safety (PIFS), a 501(c)(3) educational organization. Both non-profits are legally governed by volunteer boards of directors. These work in conjunction with the Alliance's own volunteer Advisory Council.

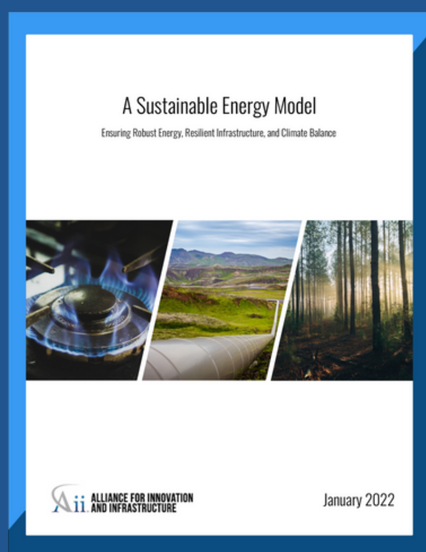
Board of Directors

ALLIANCE FOR INNOVATION AND INFRASTRUCTURE

3033 Wilson Blvd, Suite 700
Arlington, Virginia 22201

Recent Works





@AiiNonProfit

info@Aii.org | (703) 574-7376