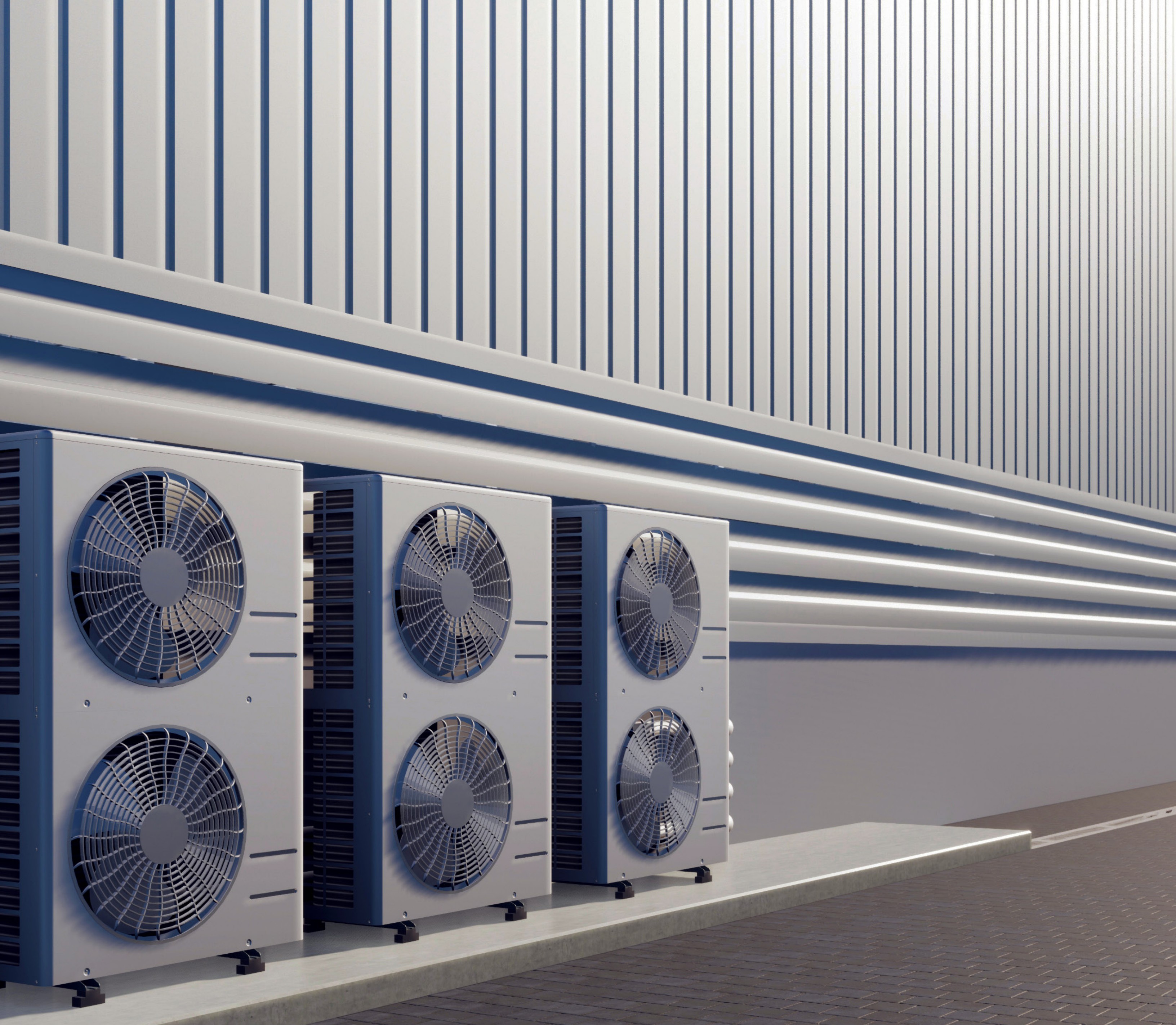

Ceres

Decarbonizing U.S. Gas Distribution
An Investor Guide

September 2023

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Executive Summary

The gas distribution industry, which owns pipes that deliver energy to homes and businesses throughout the U.S. for heating and other uses, is a key part of the transition to a decarbonized energy system. Decarbonizing the industry is essential for averting the worst impacts and economic risks of climate change since it delivers approximately 15% of the energy consumed in the U.S. and represents approximately 14% of total U.S. greenhouse gas emissions.[1]

In addition to helping address the systemic financial risks of climate change that investors are exposed to, decarbonization of the industry is also financially relevant to the $379 billion in investor-owned assets, along with continued capital expenditures planned in multi-decade assets. Perhaps even more financially significant than the risks to these existing and future assets is that decarbonization will unleash strong financial opportunities for the broader utilities sector and its investors, while continuing to provide consumers and businesses with energy that is reliable and cost competitive.

This report analyzes the viability of the different decarbonization pathways that the industry is currently adopting, considering, or facing competition from. To meet the goal of limiting warming by 1.5°C, the building sector — which we consider the most robust and relevant indicator of the emissions reductions needed in the gas distribution industry — needs to see a cut in global average end use carbon dioxide emissions by 46% by 2030 versus 2021, while global methane emissions need to drop 75% in the same timeframe, according to the International Energy Agency.

Given rapidly diminishing global carbon budgets, a policy shift already underway (reflected in the Inflation Reduction Act and state policies), major improvements in technology capabilities, and looming decisions on billion-dollar investments in multi-decade assets, now is the time for utilities to develop and implement strategies for decarbonization that are both ambitious and viable. Without grounding in viability, strategies may be merely greenwashing and lead to wasted shareholder capital, missed opportunities, and excessive costs to customers. This report highlights the advantages, disadvantages, and implications of the industry's decarbonization options, with a focus on the most viable approaches for utilities, customers, and shareholders. It is intended to help investors effectively influence and support utility companies in decarbonizing the industry.

Key findings within this report include:

1. **VIABILITY**
    a. **Electrification and efficiency-centric pathways are the most viable for decarbonization in line with a 1.5°C goal, are usually far more viable at scale than low-carbon fuels, and are already competitive against unabated gas distribution.** The excellent seasonal efficiency of heat pumps leads to very favorable economics for the customers in most of the U.S. that will be difficult for any fuel-based system to compete with, even before considering the major cost increases of switching to lower carbon fuels.
    b. **Evidence strongly suggests that renewable natural gas (RNG) and hydrogen-centric pathways are not economically viable at the scale** required for major contributions to 1.5°C alignment, even though minor contributions from these fuels may be viable and beneficial.

1 Based on EPA data on industry's own emissions and end-use combustion emissions, but before attributing upstream emissions (including fugitive methane).

c. **Deep hybrid electrification is a useful interim strategy** for decarbonization that is relevant to regions with moderate to severe winter climates. It can effectively manage electric grid congestion to avoid capacity upgrades and cost escalation. Deep hybrid electrification, which combines heat pumps with existing fuel heating systems and uses heat pumps for most of the heating season, can occasionally depend on the flexibility of existing fuel-based systems to manage capacity of the electric grid.

2. **BUSINESS CASES**
   a. **For electric-only service territories, electrification is a compelling growth opportunity** to deploy more capital while providing cost-effective decarbonization options **that benefit** customers.
   b. For dual-fuel service territories, the business case for electrification is much stronger than widely acknowledged since **electricity businesses are more capital intensive** and regulated utility earnings are directly linked to capital deployed via the rate base and cost recovery. Electrification represents an **earnings growth opportunity to deploy more capital up and down the energy supply chain** in generation, transmission, distribution, storage, and end appliances. Gas utilities are largely restricted to distribution infrastructure and have limited opportunity to capitalize fuel costs.
   c. **For gas-only service territories, the business case involves avoiding deploying capital into assets that may not be fully recovered** in their lifetime since electrification is largely outside of their control and appears inevitable. The gas distribution industry is making substantial investments into very long-lived infrastructure, which needs to be scrutinized by shareholders, regulators, and customers.

3. **JUSTICE AND EQUITY**
   a. Utility companies' plans must comprehensively incorporate justice and equity, specifically **customer access and affordability, as these are fundamental requirements for building a viable system**. Energy equity creates multiple shared benefits between the customer, utility, and investor, helping optimize the overall system and facilitate the implementation of capital expenditure plans.

4. **ADDITIONAL FINDINGS**
   a. The policy response is already happening, and more is expected. Many states are implementing or considering a combination of electrification and "future of gas" scenarios. This policy shift and favorable customer economics must be anticipated by companies in designing forward looking plans.
   b. Integrated system planning and operation is beneficial while the electric and gas grids coexist to help manage capacity needs.
   c. Synchronized decarbonization is worth pursuing since there are capacity synergies between transport and heating electrification.

The industry faces unique challenges. The U.S. gas distribution system plays a key role in meeting the winter space heating demand across a variety of climate zones. In severe winter weather, when heating is needed most and demand can spike dramatically, the peak throughput of gas distribution systems can be multiples greater than the existing capacity of electric grids in many regions.

There are capacity challenges with complete electrification in some regions — when considering the scale of electrifying the entire building stock — that have the potential to cause electric rate escalation if not properly managed.

However, we see these capacity challenges as manageable through several strategies, with deep hybrid electrification a key transitional strategy in regions that have moderate or severe winters on the way to eventual complete decarbonization. Deep hybrid electrification can have favorable economics for customers and at a system level, while resulting in significant reductions in gas volumes and emissions. Figure 1 illustrates likely contributions to low-carbon heating. These are illustrative only, as actual levels will be determined by detailed system cost optimization performed by utilities in each region.

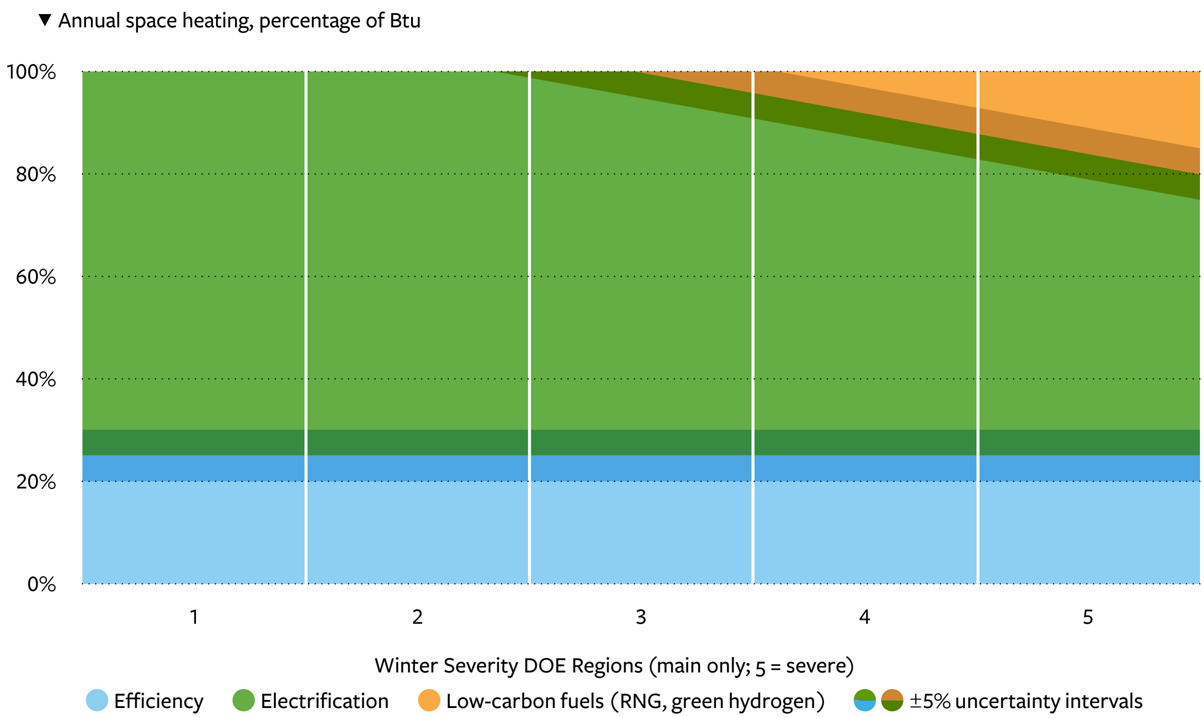
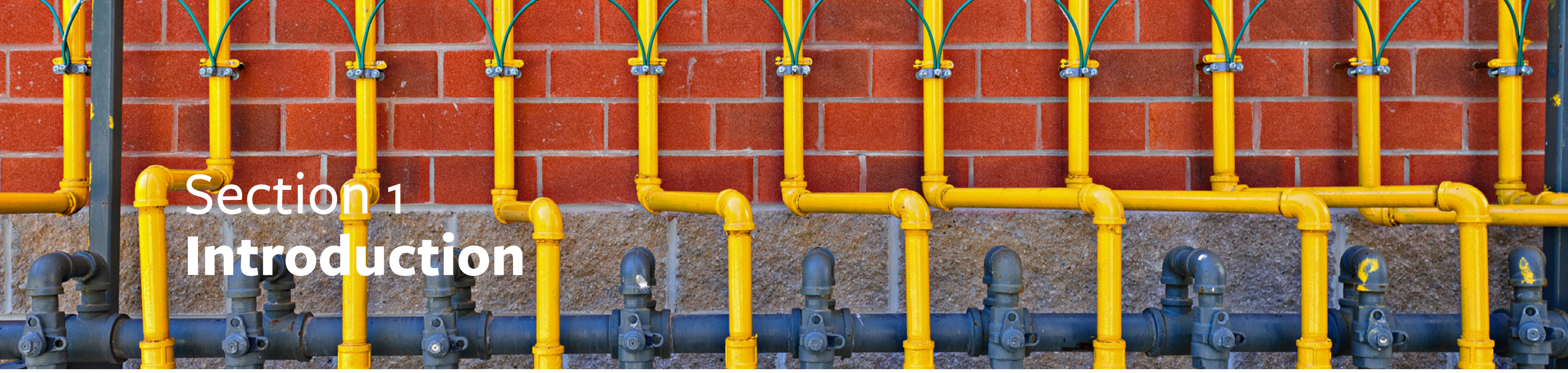


Figure 1: Electrification and efficiency are likely to feature prominently in low-carbon heating, with some contribution from low-carbon fuels in colder regions.

Based on these opportunities and challenges, our report lays out two sets of recommendations for investors and utility companies. We recommend that investors:

- Encourage multi-utility and electric utility companies to pursue decarbonization strategies in line with a 1.5°C goal, capital expenditure opportunities, and policy engagement centered on electrification and efficiency.
- Be skeptical of any utility decarbonization plans that rely on the availability of substantial volumes of RNG or blending of hydrogen without an analysis of prospective costs to consumers and availability of the fuels.
- Request detailed evidence from gas distribution and multi-utility companies of the prospective viability of their decarbonization plans at meaningful scale and its impact to customers, particularly low-income households, environmental justice households, and renters.
- Request disclosure of the underlying assumptions of gas distribution capital expenditures associated with system expansion and asset life extension, and analyses on whether these are recoverable with the prospects of significant electrification during asset lives.
- Consider directly engaging with federal and state policymakers and regulators to foster enabling economic conditions for viable decarbonization of the gas industry.

Additional recommendations for utility companies are included in Section 5.



Section 1
Introduction

Context

The U.S. has committed within its Nationally Determined Contribution in line with the Paris Agreement to addressing climate change and aims to reduce economy-wide greenhouse gas emissions by 50-52% by 2030 and to net zero by 2050. The utilities sector has a critical role to play in achieving those goals because of its scale and ability to cost effectively reduce its own emissions, the emissions of its customers and supply chains, and the emissions of other sectors via electrification. The sector overall is making progress in electricity dominated scope 1 emissions from its own operations (albeit slower than ideal in most cases). Leading multi-utility companies are also setting goals that cover the scope 3 emissions from their customers that consume gas. However, this is not yet standard practice across the entire gas distribution industry.

Many gas distribution companies are only in the early stages of forming decarbonization strategies to achieve emissions reductions. Companies and the industry as a whole are investigating and, in some cases, pursuing blending or substituting fuels like RNG, hydrogen, and hydrogen-derived fuels like synthetic natural gas (SNG). For example, the American Gas Association highlights these and other options, such as electrification and efficiency, within potential pathways in its Net Zero Emissions Opportunities for Gas Utilities report. While it is encouraging that the industry is starting to acknowledge the challenges and opportunities ahead, many companies' decarbonization strategies are vague and lack evidence of viability at scale. This report aims to highlight the advantages, disadvantages, and implications of these options, with a focus on the most viable approaches for utilities, their customers, and their shareholders.

While there are many different emission reduction scenarios that could be considered for the industry, we find that the International Energy Agency's Net Zero Emissions by 2050 Scenario, which presents direct emissions for the buildings sector and energy-related methane pathways at global levels, offers a sufficiently robust approach to 1.5°C alignment that investors and companies should defer to. On the way to net zero in 2050, this involves a gross reduction in the building's sector's end use CO_2 emissions of 46% by 2030, in parallel with a reduction of 75% in energy-related methane emissions (both against 2021 base years). Further detail on this topic is provided in Appendix 1.

Industry Summary

The U.S. gas distribution industry, with its 2.3 million miles of pipes that service 71 million customers, is currently a critical part of the U.S. energy system. Under the EPA's GHG Reporting Program, gas distribution companies reported volumes of 14.3 trillion cubic feet (Tcf) in 2021, which is 15% of total U.S. energy consumption. The industry is also a significant source of carbon and methane emissions, accounting for 14% of total net greenhouse gas emissions, including end-use emissions of 793 million metric tons of carbon dioxide for 2021. Currently, the gas distribution industry delivers mainly fossil-derived natural gas, which is primarily methane. If fully combusted, and in the absence of leaks, natural gas has a medium carbon intensity of 55 kg of CO_2 per thousand cubic feet. Unfortunately, methane is a potent greenhouse gas, and research, including by Alvarez et al (2018), has uncovered under reporting methane leakage across the supply chain.

Gas distribution — also known as gas utilities or local distribution companies (LDCs) — is a specific stage in the gas supply chain. It is distinct from gas transmission, which involves higher pressure, larger diameter pipelines that tend to shift gas long distances. Gas distribution is also distinct from gas retailing, which centers around the customer relationship, that must be won in competitive markets and is a business model much lighter on physical assets. In contrast, gas distribution is capital intensive, since investor-owned utilities had total assets of $379 billion and construction expenses of $22.4 billion in 2021. Despite the major differences in distribution and retail business models, there is a significant overlap in practice. Depending on regulation, many gas utilities have distribution and retailing services bundled together, while some holding companies have subsidiaries in both distribution and retail areas.

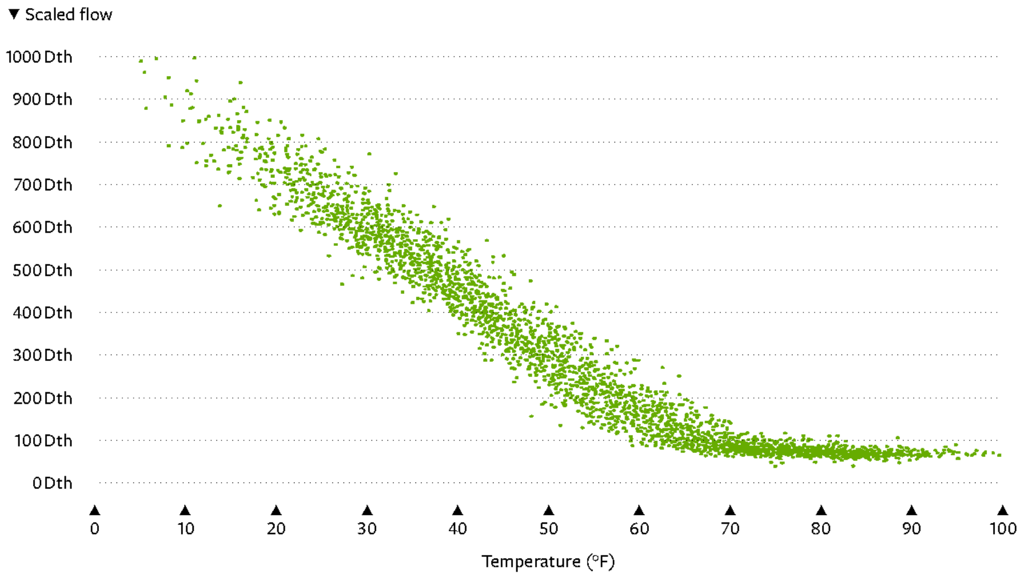
Gas utilities serve three main types of customers: residential, commercial, and industrial. While all three consume similar volumes of gas (4.6 Tcf, 3.2 Tcf, and 3.9 Tcf respectively), the residential sector is the industry's most important customer financially, accounting for around half of its revenue. Within this critical residential segment, space heating, followed by water heating, make up the biggest share of gas usage, with other uses accounting for much smaller levels of consumption, according to the Energy Information Administration's 2020 Residential Energy Consumption Survey.

Gas distribution is a natural monopoly and, as a result, is regulated, though the industry faces external competition from substitutes like electricity and other fuels. Nevertheless, with an average residential price of $12.18 per thousand cubic feet in the U.S. in 2021, and aside from the conflict-related price spikes of 2022, natural gas tends to be recognized as a low-cost fuel to the consumer.

One of the defining characteristics of the gas distribution industry — a direct result of the key role it plays in providing heating to homes and businesses — is its capacity and flexibility to respond to the spikes in demand caused by major winter events. On a national basis, the peak throughput of the gas system (excluding deliveries for electricity generation) vastly exceeds the peak capacity of the electric grid. But even this comparison understates the capacity of gas distribution due to smoothing effects. For example, during a 2019 polar vortex event in northern Illinois, the three gas utilities delivered 3.5 times the energy than the electric utility in an overlapping service territory has ever delivered in a day.

The significant peakiness of gas demand and its sensitivity to temperature due to heating load is demonstrated in Figures 2.1 and 2.2, which depict a utility's daily data anonymized by scaling.[2] For this example, heating-related flow on peak days was more than 10x the flow on non-heating days. Given the importance of heating, these severe winter events are critical for determining the required capacity needs of the gas distribution infrastructure.

2 Unfortunately, daily data for gas distribution is not readily available through the EIA or other standardized databases, although similar analysis may be found in public utility commission reports and filings.



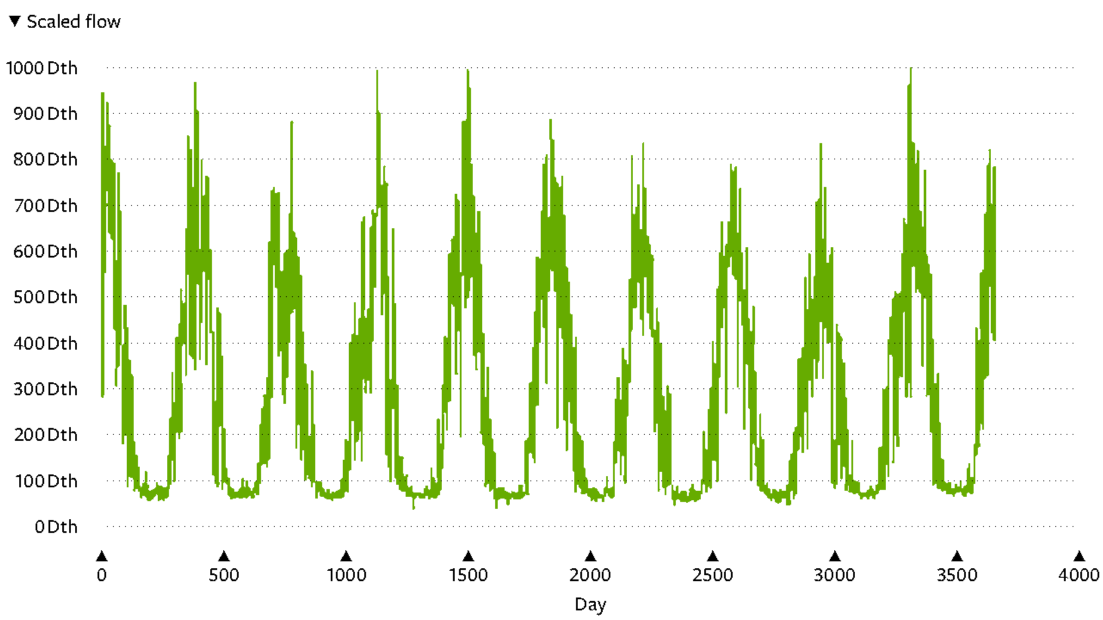


FIgure 2.1 and 2.2: Daily gas demand is very peaky and seasonal, and is strongly related to temperature. Source: Ishola (2009).

As a result of this peakiness and financial materiality, the focus of this report is space heating in the residential and commercial segments. Our conclusions are less applicable to the low-margin industrial segment, which may have more process-specific needs.

Recap of Utility Business Model Incentives

Gas (and electric) distribution companies are regulated as natural monopolies to prevent excessive pricing power. While specific definitions may vary, the basic regulatory model is demonstrated by the following simplified formula, which is often abbreviated into the phrase 'rate base':

Allowable profit = allowed rate of return on capital x allowed asset base

Under the basic rate base model, utilities are incentivized to maximize deployment of capital as long as the allowed rate of return on capital is equal to or exceeds its cost of capital. However, this is not a license to generate unlimited profits. Utilities must still prove to regulators that the capital projects are prudent, needed, or beneficial, which is a multi-factor decision that balances costs to consumers, flexibility, reliability, safety, and achieving climate objectives.

Importantly, this formula uses the term 'allowable profit' and not actual or guaranteed profit. Actual profits depend on many factors and, once a capital plan is approved by regulators, a utility must still:

- Execute on the capital projects (and its operations and finances generally)
- Obtain approvals on any changes to tariffs required for cost recovery
- Sell sufficient volumes and obtain sufficient connections at the approved tariff levels to produce the expected levels of revenue

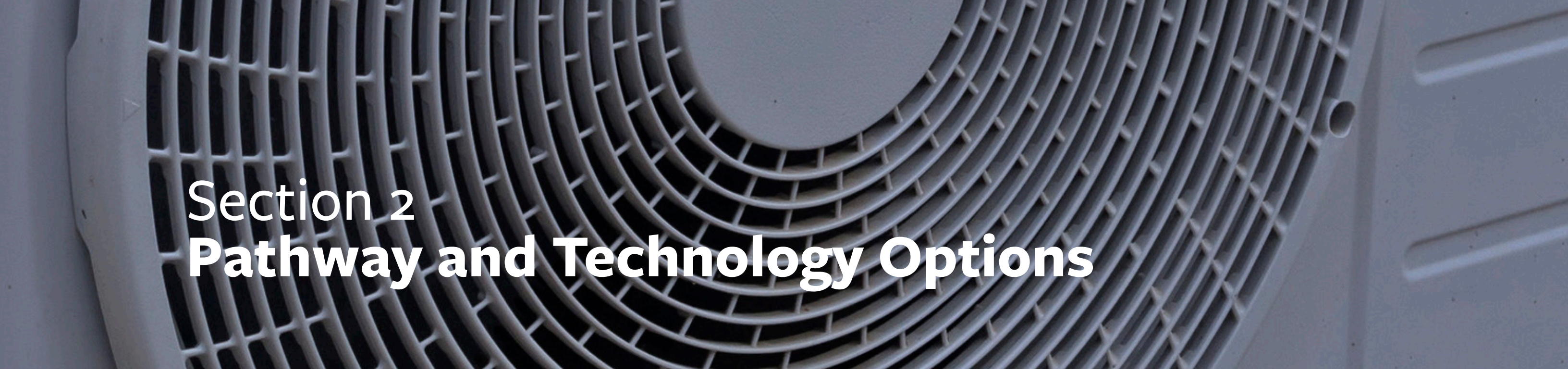
Given the prominence of space heating, the winter peak capacity needs of the distribution grid are the major determinant of investment requirements, while throughput volumes determine how those investment costs are recovered through tariffs. Since a gas distribution company's actual profits are dependent on volumes and connections, decarbonization presents an existential challenge for the gas distribution industry, even though they may be inaccurately perceived as 'protected' by the regulatory model. Utilities in states with "decoupling" may be insulated from relatively small decreases in volumes, but it remains to be seen whether this will hold true for reductions on the scale of widespread electrification.

While the above formula describes the basic regulatory model, a variation that is increasingly being adopted is performance-based regulation that aims to financially incentivize utilities to achieve specific objectives. Many U.S. states have developed specific performance incentives for gas and electric utilities, which are often related to efficiency, and new models are emerging that provide additional incentives for greenhouse gas reductions or other societal goals.

DEFINING VIABILITY

The core focus of this report is the viability of decarbonization pathways for gas distribution. To be considered viable, a decarbonization pathway must simultaneously address multiple issues and 'work' for multiple stakeholders. We believe a viable pathway or strategy must:

- Have sufficient political and social acceptance
- Be consistent with realistic expectations of future climate and energy policies at the local, state, and federal levels
- Be economic on the scale and timeframes required for meeting climate objectives
- Be affordable to customers (in aggregate and for specific groups such as low-income households, rural households, and renters)
- Reflect region-specific factors like climates, heating loads, resource availability, and grid constraints
- Be financially viable for providers of new capital (utilities, investors, or others)
- Reliably and safely meet energy needs throughout the year, especially during major winter events



Section 2
Pathway and Technology Options

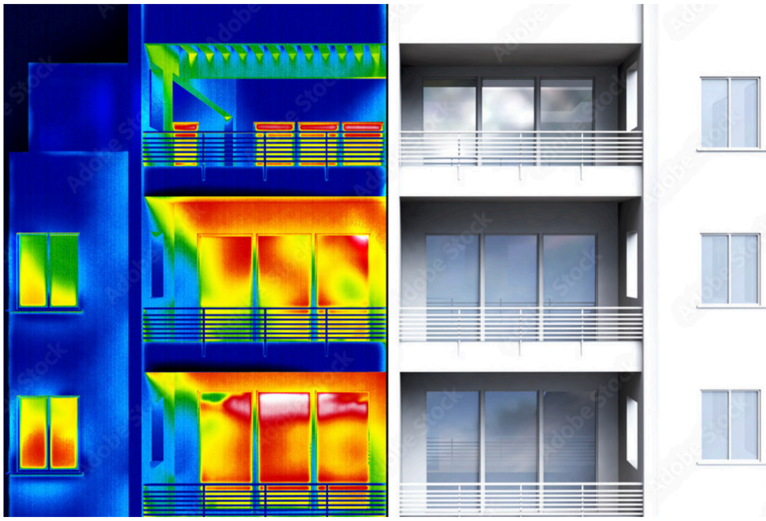
Companies are in the early stages of mapping out decarbonization strategies. But there are five main approaches and technologies that are the most relevant: Efficiency, Electrification, Renewable Natural Gas, Hydrogen, and Synthetic Natural Gas. Our research suggests that efficiency and electrification are the most viable at the required scale (see Appendix 1), while fuel-based options have cost and scalability issues but could still have a beneficial role to play at smaller scale.

1. Efficiency

Energy efficiency is the fundamental "first fuel" for achieving deep decarbonization in the utility system. Energy efficiency minimizes energy input in a system by requiring less to perform the same tasks, making it highly cost-effective and integral to building any comprehensive, low-emission energy mix. Just as critically, it is a zero-carbon resource that enhances grid reliability and effectively avoids the costs of expensive new capacity upgrades. Paired with demand response, which can be used to help avoid or redistribute high peak loads over greater time periods, efficiency offers significant potential to lower gas and electric utility rates by avoiding capacity upgrades and fuels costs through energy savings and peak demand optimization.

Efficiency also delivers other substantial social and economic benefits. Annually avoided air pollution from a 1% natural gas energy efficiency program could generate between $44.7 million and $100.6 million in public health benefits[3] by reducing the levels of fine particulate matter, which are linked to lung cancer, heart disease, work loss, and death.

For any efficiency program to be successful, adequate long-term planning will be required to ensure that programs are accessible to all residential, commercial, and industrial customers, apply to various end uses like retrofits, weatherization, and appliance switching, and serve underrepresented households, which include but are not limited to low-to-moderate income (LMI) customers, renters, and rural households. Energy efficiency is exceedingly important for utilities and should be deployed at scale, irrespective of whether buildings are electrified or use piped gas or another fuel.



3 Parameters set in the EPA COBRA Scenario Mapping Tool include all contiguous U.S. states with a discount rate of 3%. Sector selection used to generate public health estimates were Fuel Combustion: Other, Commercial/Institutional Gas; and Fuel Combustion: Other, Residential Other, Natural Gas.

A STUDY IN COST SAVINGS

An analysis by the Lawrence Berkeley National Laboratory (LBNL) offers a practical case study in how energy efficiency is an exceptionally cheap way to achieve cost savings. LBNL's study of natural gas efficiency programs in 12 states found that the **cost of saving natural gas was 40 cents per therm between 2012-2017**, compared to the national average retail price of natural gas of $1 per therm during that same period.

The analysis highlighted regional differences in costs, with the Midwest having the lowest levelized cost of saved energy, at 29 cents per therm, and the West the highest, at 59 cents per therm. These differences are likely attributed to higher allocated spending on efficiency programs in California, and the extreme climate conditions in the Midwest, which benefit substantially from efficiency improvements, such as furnace upgrades and weatherization.

The LBNL study also underscored opportunities by segment. The commercial and industrial (C&I) gas programs had the lowest weighted average cost per unit of energy saved across median and average values. This indicates that marginal spending on C&I gas efficiency programs may yield higher energy savings compared to residential and low-income groups. This finding is especially useful since C&I customers will likely have the most constrained energy need and depend to a larger extent on natural gas and low-carbon fuels in the coming decades.

However, the cost of natural gas supply is a determinant factor in the adoption of efficiency programs, so the perceived economic value of efficiency may vary. An earlier iteration of this study between 2009 and 2011, where **prices averaged $1.11 per therm**, showed that the average cost of energy saved was **38 cents per therm**. Despite falling prices, the savings from the energy efficiency programs still resulted in cost savings.

In addition to building efficiency upgrades, potential efficiency gains in the gas distribution network are meaningful. But it will be increasingly important that gas utilities balance investment with the heightened risk of stranded assets and the trade-off in efficiency that can potentially be gained by fuel switching.

Electrification fuel switching can drive large efficiency gains by saving total primary energy and reducing greenhouse gas emissions in a system. Savings attributed to efficiency and changes in the fuel mix, including the electrification of heating, has lowered global energy demand by 30 EJ between 2016-2021 compared to the business-as-usual scenario. The direct replacement of fossil fuels for low-emission electricity accounts for approximately 20% of total emission reductions by 2050 in the International Energy Agency Net Zero Scenario (NZE).

Since we do not extensively cover this topic in relation to its importance, we encourage exploring further guidance provided by resources such as the 2023 Energy Efficiency Impact Report collaboratively developed by the Alliance to Save Energy, American Council for an Energy-Efficient Economy (ACEEE), and the Business Council for Sustainable Energy and the International Energy Agency's (IEA) Energy Efficiency 2022 report.

2. Electrification

Electrification encapsulates a range of exciting technologies that have made significant advances in recent decades — in particular heat pumps and induction stoves. While heat pumps have multiple applications, including space heating, water heating, and clothes drying, our focus in this section is on heat pumps for space heating due to the importance of space heating in annual volumes and peak system capacity needs. We believe electrification is a low-hanging fruit for decarbonization across most of the U.S., although the extent of electrification may vary across regions.

Efficiency of Heat Pumps

What makes heat pumps such a gamechanger is their outsized efficiency advantage. In contrast to resistance heating, which uses electrical current to produce heat, electric heat pumps use electricity to drive an electric motor to shift heat from (or to) a source via compression and expansion of refrigerants. As a result, while the efficiency of resistance appliances cannot exceed 100%, the efficiency of heat pumps can go multiples beyond 100%.

Efficiency of heat pumps is described by the 'coefficient of performance,' (CoP) or energy output divided by energy input in the same units. Importantly, CoP varies by temperature of the source. This is represented by performance curves, which are especially relevant for air-source heat pumps, the most prevalent type of heat pump.

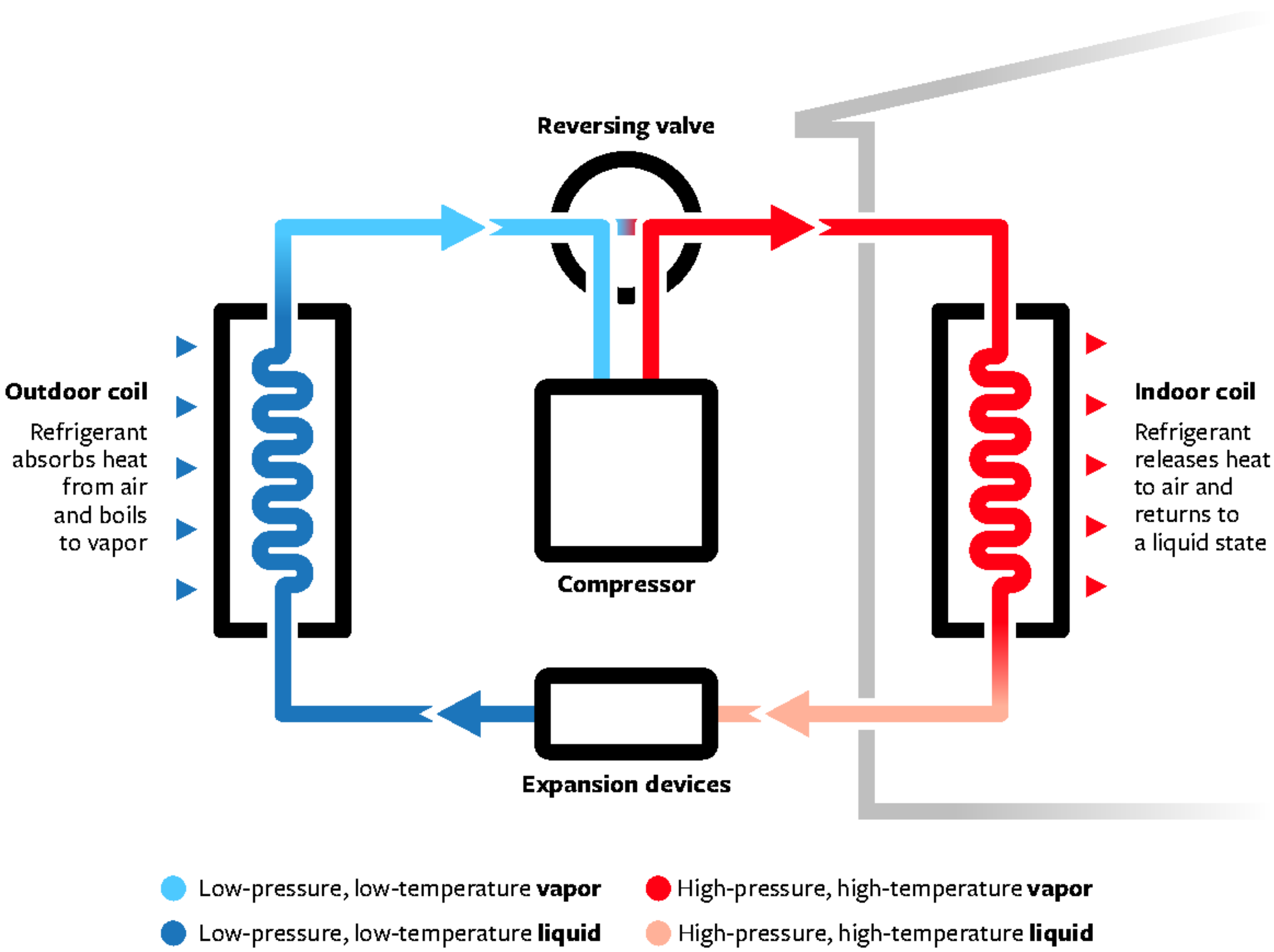


Figure 3: How heat pumps operate

Through major strides in innovation in recent years, air-source heat pumps perform much better in very cold conditions than widely recognized. In fact, their performance is considerably better than levels suggested by one gas utility's plan, which models 30°F as a critical threshold under which it assumes heat pumps won't be operated. Positive experiences with cold-climate heat pumps have been reported as far north as Maine, both as a standalone heating system and as a primary heating source with backup. Leading air-source heat pump models are able to achieve a CoP of 1.93 (almost 200% efficiency) at negative 13°F, based on our research using the Northeast Energy Efficiency Partnerships (NEEP) database and Mitsubishi's product specifications. Though this is leading performance right now, we expect this to become industry standard performance in the years ahead.

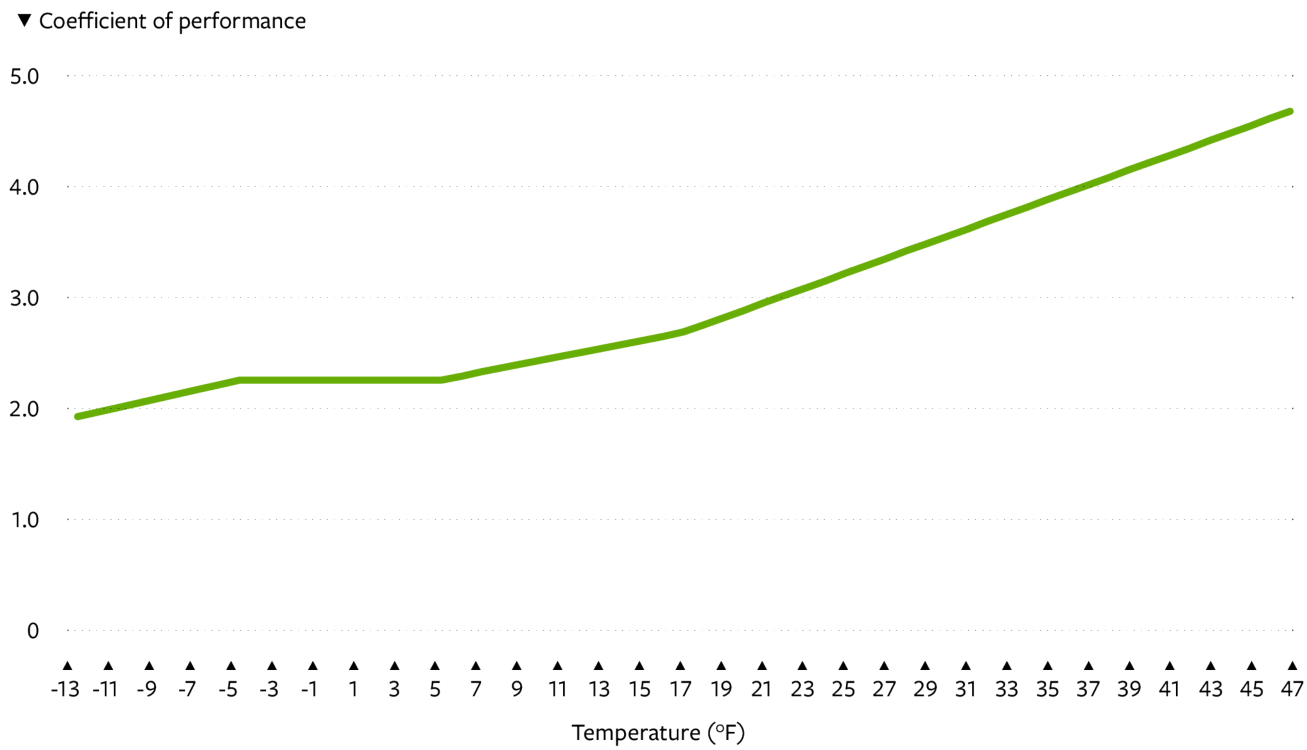


Figure 4: Impressive performance of a leading air-source heat pump, with performance determined by temperature.
Source: Mitsubishi product specification sheet.

CoP is measured at a point in time in which temperature is constant. But the strong performance of heat pumps is also clear when measured over an entire heating season using a metric called the heating seasonal performance factor (HSPF). Designed by the Department of Energy, the HSPF is based on a generic temperature distribution that is representative of the average climate for 'Region IV,' which is shown in Figure 5 (page 15) and includes key states and regions like much of Illinois, Indiana, Ohio, and the coastal Northeast. In regard to population and gas-demand-weighted measures, most of the contiguous U.S. has a climate comparable to or less severe than the generic distribution of Region IV.

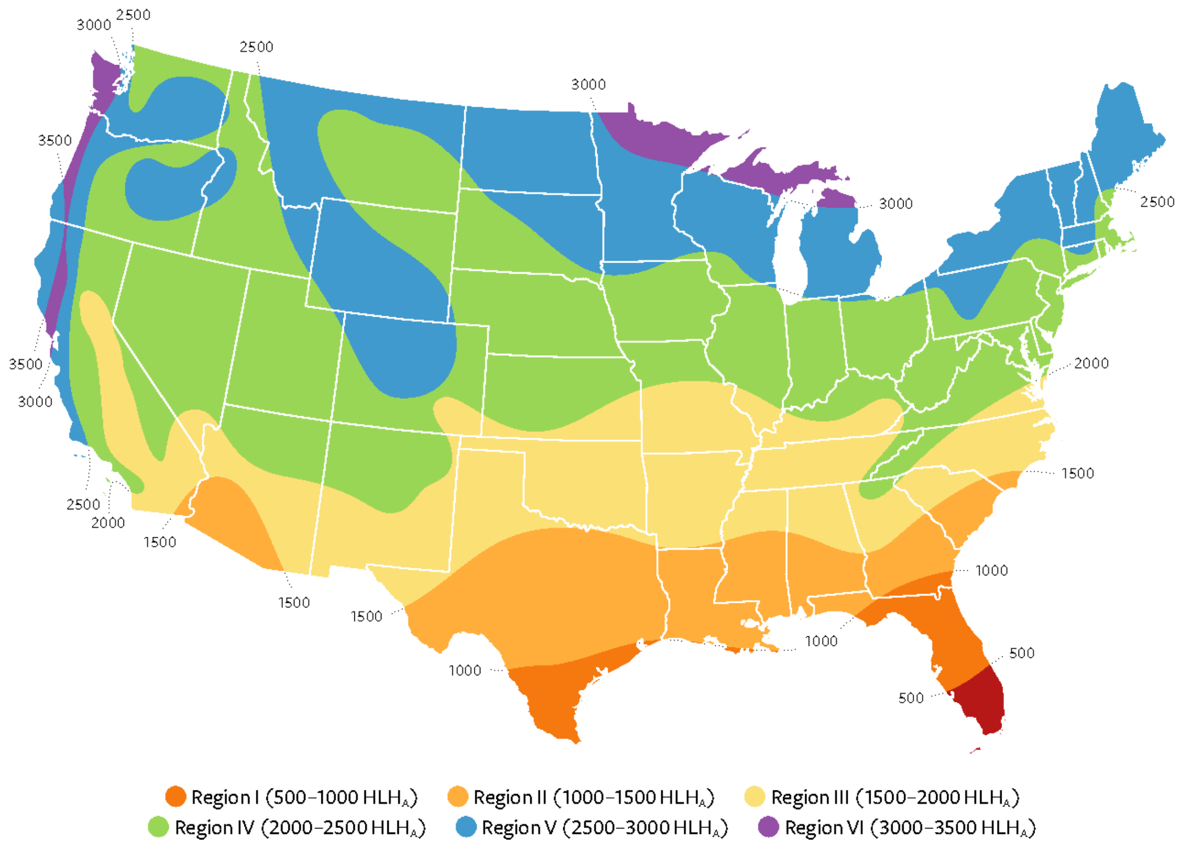


Figure 5: Heating hours shown to match DOE definitions of regions, but we recognize that heating-degree days and design day temperatures are more important for severity of heating season. Source: Department of Energy

The leading heat pumps have HSPFs that are equivalent to seasonal-average efficiency of almost 400% for Region IV. For regions with milder climates, seasonal-average efficiencies above 400% are achievable. Even in regions with the most severe climates, efficiencies above 400% are achievable for much of the longer heating season and above 200% for almost all the heating season.

The excellent seasonal efficiency of heat pumps is highly relevant to emission reductions. While it is possible to compare emissions using the average intensities of electric grids, the marginal supply of electricity is most relevant to the change in emissions. In an individual season (shorter than the planning cycle of building more renewables), much of the marginal supply of electricity stems from running gas plants more frequently. Even in this situation and considering that the existing U.S. gas-fired generation fleet has an average efficiency of 44%, the 400% efficiency that is possible with heat pumps still results in lower system-level emissions compared to direct combustion of gas for heat at 90-95% efficiency.[4]

A life cycle and multi-year planning perspective is even more relevant than single-year metrics since cumulative emissions determine climate outcomes and the U.S. electric grid is rapidly decarbonizing. Over a multi-year horizon, the marginal supply of electricity will be dominated by renewables, with additional gas-fired generation representing a much smaller role. This perspective shifts the emissions reduction advantage of electrification to being overwhelmingly favorable compared to direct combustion of gas, even while there is still some gas in the marginal supply of electricity.

4 A more precise analysis would consider slight transmission and distributions losses of both systems. This rough analysis shows that heat pumps can reduce emissions by around half in the first year, even when marginal electricity comes from gas.

Economics of Heat Pumps – User Perspective

Electricity is often considered to be more expensive than gas, which is true on a simple energy content basis and is relevant to resistance heating only. But once the efficiency advantage of heat pumps is taken into consideration, at **U.S. national averages**, electricity is 33% cheaper than gas per unit of heat delivered — the tangible result that matters most to consumers.

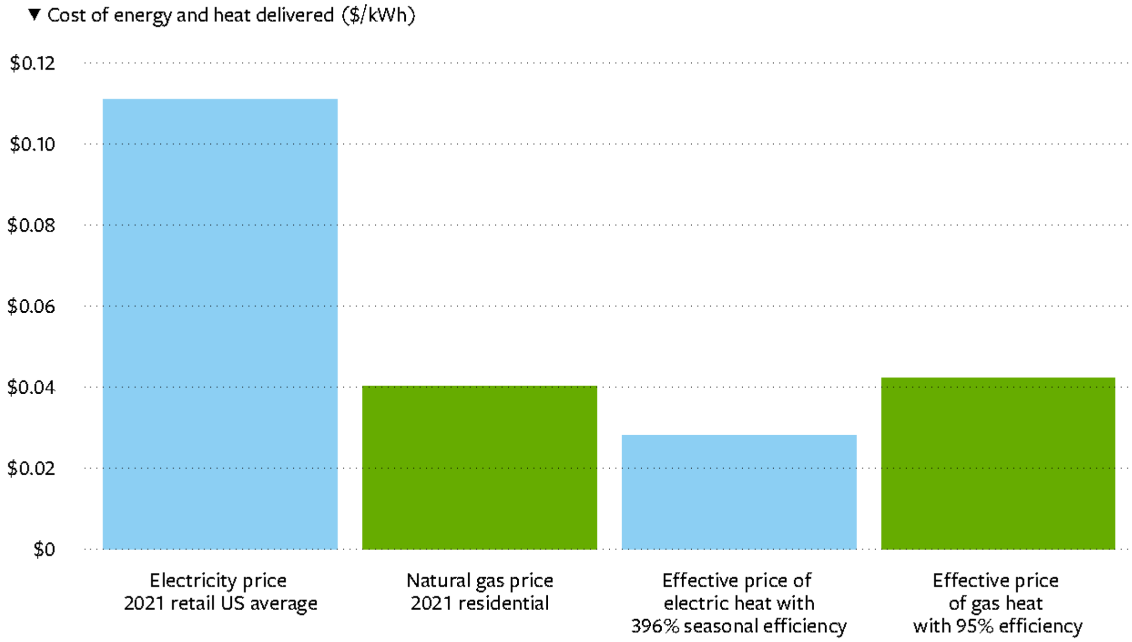


Figure 6: After considering efficiency, electric heating (with heat pumps) is cheaper than natural gas at national average prices. 2021 prices are used to avoid extrapolating peak prices from 2022. Source: EIA (electricity and gas prices), Ceres analysis.

Heat pumps can be cheaper than dual gas furnace and air conditioning systems (which is the relevant comparison since heat pumps also function as air conditioners in summer). RMI's analysis of Wisconsin Public Service Commission (PSC) contracted research shows that upfront costs of air-source heat pumps range from $2,300 to $9,000, depending on size, with ductless models being cheaper than ducted models. These equipment costs are prior to installation costs and incentives such as offered under the Inflation Reduction Act. After state rebates, combined equipment and installation costs average about $14,000, according to analysis conducted by Carbon Switch, and further incentives provided by the Inflation Reduction Act can achieve savings of up to $2,000 per household and between $8,000-$12,000 for qualifying low- and moderate-income households

IEA analysis for the U.S., which considers both capital costs and ongoing operating costs, shows that heat pumps have lower levelized costs than combined gas and air conditioning systems — even without policy incentives. With policy incentives, the economic advantage for the user shifts even further in favor of heat pumps. For example, in buildings with an existing fuel-based heating system that are not due for replacement, additions of small ductless heat pumps in combination with the existing system can be particularly useful for managing upfront costs (including electric panel upgrades), while still gaining most of the benefits from the efficiency advantages and cost savings of electric heat pumps across the season.

Primarily because of the efficiency advantage of heat pumps that results in very low operating costs and major emissions reductions, we anticipate that any fuel-based system, decarbonized or not, will struggle to compete with electrification. Reinforcing this trend, it is likely that policymakers will support the most cost-effective decarbonization options and technologies, further reducing electrification costs to the consumer.

Economics of Heat Pumps – A System Perspective

The economics of heat pumps are more complex at the system level when considering scenarios with widespread retrofits for much of the existing building stock. Yet, while electrification can involve a complete switch of a building's entire heating system and other appliances, it can also take a hybrid approach that combines electric heat pumps with existing fuel-based heating.

We consider deep hybrid electrification to be when most of a building's annual heating needs are met with electric heat pumps, while the flexibility of the fuel-based heating is still used for infrequent severe weather events. This is distinct from shallow hybrid electrification, where fuel heating would be used more frequently.

Complete electrification involves a reliance on the electric grid and heat pumps for all of the season's heating needs, even during the most severe winter events like polar vortex conditions. Complete electrification implies removing the gas distribution infrastructure and appliances in the existing building stock (and oil and propane heaters too).

Deep hybrid electrification, on the other hand, retains the gas distribution infrastructure and the existing heating appliances so that those systems can be used infrequently when needed in severe winter events. Rather than completely replacing the legacy system, deep hybrid electrification requires deployment of electric appliances so that most of the annual heating and other needs are displaced, and annual fuel volumes and emissions decline significantly.

Deep hybrid electrification, since it relies on two systems, often raises concerns about duplicative costs. At the aggregate level, these duplicative costs are likely to be manageable, since this is most relevant to certain capacity-constrained and colder winter regions. National citygate and end-user prices indicate that variable costs are a major contributor to total costs for gas utilities. Further, given the average age of pipes exceeds 30 years, much of the fixed cost structure of gas utilities is capital costs on assets that can include construction costs from decades ago less many years of depreciation. In contrast, complete electrification in severe winter regions with major electric capacity upgrades would involve substantial capital costs on an asset base at current or future construction costs that initially wouldn't have been depreciated. We acknowledge that electrification will have impacts on if and how utilities recover unavoidable fixed costs and allocate these between connection and volumetric charges for remaining customers and volumes. This potential for cost escalation on the stranded gas users raises affordability concerns that we address in Section 4.

Many regions and states of the U.S. — especially California, the Gulf Coast, and the South Atlantic — may already be suitable for complete electrification. Complete electrification at scale is an easier prospect where a milder climate coincides with spare winter capacity on the electric grid. For colder regions, incomplete but deep electrification may be a better approach for the next decade or two.

Heat pumps are highly capable of meeting heating needs when looking at individual buildings. But the challenge ahead is not just deploying a million heat pumps (i.e., the average annual rate of deployment from 2015-2020), it's in installing heat pumps in all 56 million U.S. homes that currently use natural gas, five million homes using heating oil, and five million homes using propane as their primary heating, even before considering the commercial and industrial sectors. Rolling out heat pumps (and other appliances) into tens of millions of homes will affect the capacity needs of the electric grid.

The extent of this impact depends largely on how electrification is pursued. With complete electrification — where oversized heat pumps are designed to meet 100% of a building's needs in all hours, including polar vortex conditions — the increase in the required electric grid capacity would be especially significant. In regions where temperatures occasionally fall well below –13°F, lowering the efficiency of even the best air-source heat pumps, supplementing with resistance heating becomes a possibility and the increase in capacity of the electric grid could be comparable to the size of the current gas grid. With deep hybrid electrification, heat pumps can be more conservatively sized, with capacity needs in the worst winter events supplemented with fuel heating. The required capacity upgrades for the electric grid could be much more modest — possibly a small fraction of complete electrification, depending on region and how hybrid systems are operated.

Since investment into the electric grid is closely linked to its capacity needs but the annual energy draw of heat pumps is modest given their excellent efficiency, the capacity implications of complete electrification are not simply a technical issue. They have significant economic implications in some climate regions.

Despite the long-term challenges associated with decarbonizing the entire building stock, electrification can still occur at very meaningful scales in the interim. For example, RMI's analysis highlights these kinds of opportunities even in areas with very harsh winters like Wisconsin, where 800,000 heat pumps could be deployed without reaching capacity limits (before considering other non-residential sources of load). For context, there are 2.7 million housing units in Wisconsin, with 65% relying on gas heating.

There are also opportunities to alleviate capacity constraints by creating space on the existing electric grid by making efficiency upgrades to building envelopes and modernizing the heating systems of the 65 million homes already reliant on electric heating.

Complete electrification is not the only electrification option for achieving deep emissions reductions in the next few decades. Deep hybrid electrification can avoid most of these capacity problems and resulting tariff escalation. We consider it reasonable for electric and gas utilities to base their decarbonization strategies around assumptions that policymakers will pursue the type of electrification that makes sense in their climate region and given their grid constraints. In regions with milder climates and spare winter capacity on the electric grid, it is more reasonable for companies to assume that policymakers will pursue full electrification. In harsher climates, deep hybrid electrification may make more sense for policymakers and companies to pursue as an interim strategy. Determining what approach is optimal and most probable for a specific region will need to be based on detailed system modeling.

DIFFERENCES IN CAPACITY CHALLENGES

Ceres has analyzed the capacity implications of complete electrification of the design day heating loads of Peoples Gas (in Chicago) and Southern California Gas to demonstrate how climate, capacity planning, and heating electrification interact at the system level. For Peoples Gas, the design day midpoint forecast heating load is **1.8 trillion Btu** on an assumed average temperature of -16°F for that day. For SoCalGas, the 1 in 10-year forecast is similar in scale at **2.1 trillion Btu** on an assumed average temperature of 42°F for that day. While gas networks have some flexibility to adjust pressure to account for intra-day variations in demand and plan for peak day needs, electric grids must be continually in balance, and planning for hourly and finer intervals is critical.

We modelled hourly demand for the electric grid based on a peak-day daily demand profile for gas interacting with the intraday-variability of temperatures, and the performance curve of leading heat pumps. Beyond -13°F, we have assumed heat pump CoP falls linearly to 1.6 at -20°F, and then to 1.0 at -30°F. This second assumption is conservative to allow for the possibility that consumers may supplement heating needs with resistance heating when temperatures fall below operating ranges, and this is not the standalone performance of heat pumps.

Our analysis indicates that, in the absence of efficiency or demand response, fully electrifying the heating load of Peoples Gas would add electric load of around 16 GW and 11 GW respectively on a peak 1-hour and peak 24-hour basis. These are significant values considering this is just one utility in the region, and PJM and MISO are already facing winter constraints as more of their large coal fleets are retiring. These additional capacity requirements are a challenge for maintaining low electricity rates because the additional electric load from electrifying all of Peoples Gas' 2024 forecast heating load would be only around 5 TWh after considering heat pump seasonal efficiency. Even if we assume that demand response meets the 1-hour need, the 24-hour capacity need is equivalent to a capacity factor of only 5% before considering load changes from cooling. This is not much incremental electric volume to spread additional capital costs across. In this case, complete electrification of the entire building stock's heating load could add significantly to the capacity requirement of the existing electric grid and risks cost escalation if not managed wisely.

In contrast, the capacity implications for electrification of heating in Southern California are much milder because the performance of heat pumps is considerably more favorable even in the most extreme temperatures that this region will likely experience. We model complete electrification of SoCalGas' peak heating load to equate to 1-hour and 24-hour capacity needs of around 7 GW and 5 GW respectively. Since the California Independent System Operator (CAISO) has existing spare winter capacity, much of this heating-related winter capacity may not be additive to the needs of the existing electric grid in aggregate, although electric utilities would still need to plan for capacity at the circuit level.

Capacity challenges are not a reason to delay electrification. Instead, electrification should be pursued wisely with awareness of its challenges at scale and across different regions.

Ground-Source Heat Pumps

Ground-source heat pumps are another potentially viable option. A detailed 2009 study prepared for the Department of Energy estimated that the payback period for installing ground-source heat pumps is less than 10 years in many U.S. regions, compared to gas furnaces and air conditioning. While there are some disadvantages compared to air-source heat pumps due to complexity and greater upfront installation costs, these systems benefit from more constant ground temperatures and maintain exceptional performance in any conditions. From a system perspective, the capacity implications of widespread adoption would be significantly lower, especially for more severe climates.

Networked geothermal systems are another variation of electrification and ground-source heat pumps. Pilot projects are underway with National Grid and Eversource in the Northeast. We consider these systems to be potentially beneficial in certain applications, particularly in dense areas, but it is unclear at this stage if the economics for widespread adoption are sufficiently compelling versus standalone heat pump systems.

3. Renewable Natural Gas

Renewable natural gas (RNG) is produced from converting biomass into methane and can either be a drop-in substitute for or blended with fossil gas. As a result, it benefits from the cost advantage of compatibility with the existing gas storage and transportation infrastructure and end-use appliances.

While individual projects may be viable and beneficial in some cases, the viability of using RNG at scale to decarbonize the gas distribution industry faces major challenges.

There are significant issues with the availability of the amount of feedstock required to produce RNG at scale, which would raise costs significantly to the end consumer if RNG is relied on extensively for decarbonization strategies. Biogas fuel costs are estimated to be six times higher than projected wholesale gas prices in 2040 and a scenario with a high reliance on biogas leads to a 315% increase in average customer utility costs, according to a recent study by ACEEE. Issues around scalability of RNG are further discussed in Grubert (2020).

A 2019 study by consultant ICF for the American Gas Foundation found the U.S. RNG resource potential in 2040 to be 1,660 to 3,780 trillion Btu, excluding the non-biogenic fraction of municipal solid waste. While this is significant in absolute terms, it is modest compared to total U.S. gas consumption of 31,800 trillion Btu in 2021. The production potential at less than $10 per mmBtu — which is still very elevated compared to fossil gas and electrification — is less than 1% of total U.S. gas consumption in 2021. With a scarce RNG supply, gas utility companies will be competing with many other end users, including those in hard-to-decarbonize industries, which may have the ability to outbid gas utilities since the economics of their end-use products may be less sensitive to energy costs.

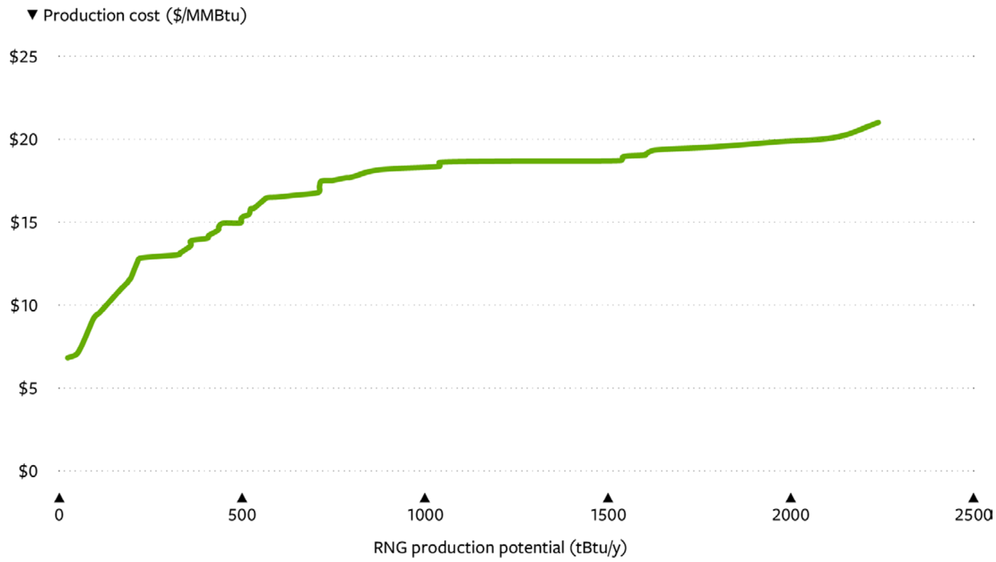


Figure 7: Affordable RNG has a very limited production potential. Source: ICF 2019 report.

Aside from prohibitive costs at scale that would worsen the energy burden, there are other justice and equity implications of high reliance on RNG in decarbonization strategies. One key feedstock for RNG is the waste from concentrated agricultural feeding operations (CAFOs) since volumes of waste collected in more pasture-based or free-range operations are much lower. There are multiple sustainability issues with CAFOs. Aside from the obvious animal welfare concerns of large-scale intensive agriculture, there are also environmental justice problems. For example, health impacts on neighboring communities have been documented in North Carolina, with the impacts felt most acutely by lower income and minority communities since CAFOs tend to be clustered in those communities.

Many of these impacts are not directly attributable to RNG production itself, but rather the decision to build the energy system of the future with intensive agriculture is controversial and poses significant sustainability issues. While gas utilities are not expected to solve all of these societal issues, they must consider the extent to which policymakers and stakeholders may support such energy sources over the next five decades.

Another concern associated with RNG is that its climate benefits are often exaggerated. Proponents of RNG commonly cite the high global warming potential of methane and the resulting major benefit of methane emission avoidance. While there is some merit, such logic is dependent on an assumption that methane would otherwise be allowed to be emitted unrestricted for multiple decades. Landfill gas — an important source of RNG — is already being captured and flared at large landfills, and it is plausible this low-cost minimum standard could be applied to smaller landfills and agricultural operations too. Further, anaerobic digestion of solid agricultural waste largely does not address agriculture's main methane source, which is ruminants' enteric fermentation. In intensive dairy systems, manure storage accounts for only 15-20% of methane emissions, with methane contributing about half of total lifecycle emissions.

4. Hydrogen

Unlike RNG, hydrogen is not a drop-in substitute for fossil gas. Instead, hydrogen must either be diluted at low blends for compatibility with the existing gas infrastructure and end-use appliances or used via specialized transport and storage infrastructure and modified appliances. These constraints apply to all types of hydrogen irrespective of the production method, however green hydrogen[5] is typically the focus of low-carbon strategies.

5 Green hydrogen is produced via the process of electrolysis wherein water is passed through an electrolyzer and split into hydrogen and oxygen using renewable energy.

Beyond blending limits, which are still under investigation, hydrogen's potential as a widespread replacement in the gas distribution industry is very doubtful due to economics, given the likely need to replace much of the millions of miles of existing pipes with a dedicated hydrogen network.

Limited Blending

While there is some potential for blending green hydrogen in gas distribution networks, there is currently significant uncertainty around the levels of blending that are technically viable, let alone economically feasible. That makes it difficult to determine emissions reduction potential and flow on costs to consumers. According to DOE, demonstrations have shown blends of less than 1% to 30% as technically possible, though economic viability is not explicitly considered.[6] The DOE is coordinating a major research project with the national research laboratories, HyBlend, to assess the blending potential of hydrogen. HyBlend is expected to develop an open-source tool for network upgrades by late 2023. In the interim, a report from the National Renewable Energy Laboratory (NREL) on the technical potential and challenges of hydrogen blending finds that Hawaii Gas' 12% to 15% blend is the leading long-term demonstration of technical viability, albeit at a lower pressure than peers.[7] The Electric Power Research Institute (EPRI) Low-Carbon Resources Initiative is also investigating the technical potential of hydrogen blending, but as of June 2023 had not yet published research specifically on gas distribution. However, in its economy-wide modeling, EPRI currently assumes a blending limit of 20% by volume, which approximately equates to 7% by energy.

Research initiated by the California Public Utility Commission (CPUC) identifies safety as a concern as hydrogen blending approaches 5% by volume under a system-wide blending injection scenario, since blending must consider vulnerability across all infrastructure components (and is limited by the most vulnerable component). The study finds that blending of up to 5% in steel pipes is generally safe, but that higher levels increase the risk of leakage and embrittlement. Similarly, blends greater than 20% present a higher chance of permeating through plastic pipes.

Given these modest blend level potentials, hydrogen depends on dilution by substantial volumes of methane gas being transported and combusted across the existing infrastructure. Its potential contribution to decarbonization also declines as total gas volumes decline, just as decarbonization needs increase.

IEA analysis shows that global levelized production costs of hydrogen produced with low-carbon electricity ranged from $3.2 to $7.7 per kg in 2019. Analysis by RMI in 2021 included costs of storage and predicted green hydrogen to fall to around $2.15 in Houston in the 2026 to 2030 timeframe. On an energy content basis, this is still expensive at around $19 per mmBtu. Clearly, even modest blends can lead to cost escalation for gas distribution utilities, even before considering higher maintenance or shorter asset lives through corrosion and embrittlement, for only minor emissions reductions. As an example of the potential, the IEA's Net Zero by 2050 report assumes that by 2030, the global average hydrogen blend by volume will be 15%, leading to CO_2 emissions reductions from gas consumption of around 6%.

Infrastructure Replacement

Much higher blends of hydrogen are technically possible, and this is already proven by the existence of the hydrogen grid. However, dedicated new infrastructure would be required for hydrogen to have a major contribution to the decarbonization of gas distribution. Dedicated hydrogen grids may expand and be developed in certain areas with specific needs (like in specialized industrial applications), but this approach is very improbable as a large-scale solution for the gas distribution industry since it would likely involve mass replacement of pipes (including mains and service), other infrastructure, and end-use appliances.

6 Assumed to be based on volume, though not specified.

7 Assumed to be based on volume, though not specified.

In 2015, the DOE estimated, using an extrapolation of AGA analysis on 2011 costs, that it would cost $270 billion dollars to replace all of the most methane leak-prone pipes, which amounted to just 9% of distribution mains. Even before considering end-use appliances and up-to-date construction costs, replacing much of the 2.3 million miles of distribution pipes so that they are compatible with high blends of hydrogen could easily run into the trillions of dollars. This need for replacement appears to be most certain for steel pipes (37% of mains miles) but is also a possibility for plastic pipes (61% of mains miles) since NREL research states on the consensus in the literature: “Multiple studies have also found that hydrogen affects polymer pipeline material properties; however, the degree of the hydrogen’s effect is less clear for polymer pipeline material than for steel.”

While this hypothetical opportunity to deploy trillions in capital would be beneficial to gas utilities’ rate bases and earnings (which likely explains why certain utilities are in favor of this pathway), the scale-up in capital costs on similar throughput volumes would lead to multiples-higher bills for consumers that would make this pathway unworkable. For example, 17% of the DOE’s 2015 estimated costs, about $45 billion, would fall on low-income households (households below 150% of the poverty threshold). This would only exacerbate the consumer-led electrification death spiral, which is already looming for the gas grid even before such cost escalation. Since the costs of hydrogen to consumers are dominated by upgraded distribution infrastructure costs, the lack of viable hydrogen-centric pathways persists even if the DOE’s Hydrogen Shot’s objective of achieving an 80% reduction in green hydrogen costs in 10 years to $1 per kilogram is achieved.

Analysis by Energy Innovation, an energy and climate think tank, shows that the Inflation Reduction Act upends hydrogen economics by including a $3 per kg incentive for low-carbon hydrogen production (including green hydrogen). However, Energy Innovation emphasizes opportunities for displacing gray hydrogen production and states that “cheap hydrogen should not encourage its use in applications better served by direct electrification like buildings or transportation. Regulators should remain wary of gas utility proposals to blend hydrogen into pipelines, as they would achieve few emissions reductions before facing costly dead-ends while increasing threats to public safety.”

5. Synthetic Natural Gas

Synthetic natural gas (SNG) is derived from hydrogen and is another theoretically plausible decarbonization option for gas distribution. There are several downsides to SNG, but like RNG its main advantage is it is compatible with the existing gas infrastructure. The downside compared to hydrogen options is that it re-introduces carbon into the equation. This is a consequential drawback because methane has a high global warming potential. Manufacturing SNG also involves another conversion process, which adds another layer of costs and efficiency losses compared to green hydrogen production.

Since gas distribution is not concentrated, carbon capture is mostly irrelevant and gas distribution featuring SNG is not a closed loop for the carbon that is introduced. SNG depends on a suitable source of carbon as an input and properly accounting for that carbon in a virtual closed loop. However, with decarbonization being broad-based, these potential sources of ‘unclaimed’ carbon will become increasingly scarce. Providing carbon to the gas distribution industry would merely be a double use of the carbon and would not be counted as a permanent offset that many firms would likely be seeking to meet their net zero targets or obligations.

Section 3
The Business Cases

The Business Cases for Electrification-Centric Pathways

There are three business cases within the sector for pursuing electrification-centric pathways that vary depending on the fuel offering to each customer. Individual companies may experience all three depending on the overlap of their service territories. Nevertheless, all three business cases center on capital deployment since this is the driver of long-term earnings and shareholder value under an assumed rate-base regulatory model.

- For **electric-only service territories**, electrification is a compelling growth opportunity to deploy more capital while providing cost-effective decarbonization options to customers.
- For **dual-fuel service territories**, the business case for electrification is much stronger than widely acknowledged since electricity businesses are more capital intensive and regulated utility earnings are directly linked to capital deployed via the rate base and cost recovery. Electrification represents an earnings growth opportunity to deploy more capital up and down the energy supply chain in generation, transmission, distribution, storage, and end appliances. Gas utilities are largely restricted to distribution infrastructure and have limited opportunity to capitalize fuel costs.
- For **gas-only service territories**, the business case involves avoiding wasted capital since electrification is largely outside of their control and appears inevitable. The gas distribution industry is making substantial investments into very long-lived infrastructure, which needs to be scrutinized by shareholders, regulators, and customers.

On the surface, given the excellent efficiency and lower operating costs of heat pumps for consumers, it may appear that electrification erodes the potential business of the utility sector in aggregate. However, for regulated utilities, revenue does not directly equate to long-term earnings or shareholder value. Instead, it is the amount of capital deployed that largely determines long-term earnings, within the constraints of regulatory approvals, reliability, safety, and affordability. In contrast, operating costs are merely recovered with little impact on long-term earnings (that's to say, money in, money out).

For 2021, operating costs, excluding taxes and depreciation, of investor-owned gas distribution companies were 65% of revenue ($28 billion on revenues of $43 billion). Fuel costs are a big contributor to operating costs and the end cost to consumers. In 2021, based on U.S. average citygate prices of $6.02 per thousand cubic feet, fuel costs to distribution utilities made up almost half of the price to residential consumers at $12.18 per thousand cubic feet, and even higher shares for the lower margin commercial and industrial sectors.

In contrast, investor-owned electric utilities are already capturing a larger share of the product's final value to end consumers as capitalized costs. Operating costs as a percentage of total revenue were lower, at 60% of total revenue ($232 billion on revenues of $386 billion). However, electricity and fuel purchases make up half of operating costs on 2021's mix of electricity generation. In the coming decades, electric utilities have a major opportunity to convert much of these fuel operating costs to capital costs by increasing the mix of renewables, which will shift the cost structure even more in favor of electric utilities.

Aside from these cost structures, strategically, gas distribution is just one link in the energy supply chain. It has limited opportunity to vertically expand and deploy capital upstream or downstream of itself, unless the company is willing to move outside the regulated business model. There are limited opportunities for additional rate-based capital deployment under fuel switching approaches for gas distribution, especially once full replacement of pipes and appliances for high hydrogen blends is ruled out for most distribution customers due to prohibitive costs (apart from certain specialized industrial applications).

In sharp contrast, electric utilities have significant opportunities for vertical expansion and deployment of capital across the electric-energy supply chain. Electric utilities have opportunities to deploy rate-based capital across primary energy production (renewables), storage, transport, (both transmission and distribution) and even end use via rate-based efficiency and electrification programs. Even those electric utilities that are restricted by regulation from owning renewables have significant capital deployment opportunities in the enabling infrastructure.

Electric utilities are evidently more capital intensive than gas utilities and are therefore more profitable under the rate-base regulatory model. Investor-owned electric utilities had total assets of $1.94 trillion, according to EEI, while investor-owned gas utilities had total assets of $379 billion, with investor-owned being 64% and 92% of each industry respectively, based on customer numbers.

The greater capital intensity of electric utilities can be demonstrated at the company level. For example, Xcel's Public Service Company of Colorado, which has similarly sized electric and gas operations in terms of customer numbers and miles of pipes, has capital intensities on its electric business that are 11.6 and 4.6 times its gas distribution business on peak capacity and annual throughput measures, even though the company partly relies on procured electricity.

Business Line	Customers (million)	Distribution pipes (thousand miles)	2021 Peak Demand (GW equiv)	2021 Annual Deliveries (TWh equiv)	Asset Base ($b)	Rate Base per Peak Capacity ($b/GWeq)	Rate Base Per Throughput ($b/TWheq)
Electric	1.5	24	7.0	35.0	10.3	1.5	0.29
Gas	1.5	23	28.3	56.5	3.6	0.1	0.06
Capital Intensity Multiple						11.6	4.6

Table 1: Gas deliveries exclude those to power generation. Gas peak demand is a peak daily throughput during Winter Storm Uri converted to an hourly average. Sources: Xcel 10K, EEI Database, EPA GHGRP data.

While the industry's aggregate assets and the Public Service Company of Colorado's example are based on historical investments over many decades, and the impact on electrification on capital deployed depends on whether complete, deep hybrid, or shallow hybrid electrification is pursued, the greater capital intensity of the electric industry should be sufficient to offset the reduced energy volumes resulting from significant heat pump seasonal-average efficiency.

Case Study: Edison International

Southern California Edison (SCE) is Edison International's energy supplying entity, servicing approximately **50, 000 square miles** of Southern California. In 2021 the company **announced a commitment** to install 250,000 heat pumps and provide electrical upgrades to 65,000 households in its ongoing effort to deliver on California's 2030 decarbonization goals, reduce greenhouse gas emissions 40% by 2030, and achieve carbon neutrality by 2045. SCE estimates that the state must reduce emissions an estimated 4.1% annually from 2019 to 2030 to place California on a firm trajectory to meet its goals. This projection is a large jump from the current pace of about 1% (2021) annually and at this scale, SCE approximates that California is at risk of missing its target by **between 12% and 35%** (accounting for 30-90 million metric tons (MMT).

To address this gap, SCE developed a building electrification (BE) strategy spanning across three programs: residential customers "BE Ready Home," commercial customers "BE Business," and, "BE Ready Catalina," for the energy-isolated island community in Catalina. Offerings are varied across each program. But common attributes include focusing on retrofitting existing gas appliances, with the expectation that building codes will cover new construction BE requirements, and tiered financial incentives to provide no or low-cost purchase and installation of electric equipment and customer-side infrastructure.

The programs recognize affordability as a historic barrier to increased uptake of BE measures and aim to improve accessibility in under served customer groups. For example, SCE is apportioning **88% of total funding to residential and the remaining 12% to commercial customers** to provide no or low-cost servicing. By offering low or no-cost solutions, the utility will help address the split incentive barrier between owner and tenant through targeted assistance to heavily incentivize owners while keeping costs low for tenants. Since SCE's grid costs are largely fixed, additional electric sales are distributed across set operating costs, effectively driving down electric rates. The utility estimates residential customers to reduce their average monthly bill by **$0.59 in 2028, and $0.69 for 2029 through 2038**.

SCE's proposed portfolio leverages building electrification as a critical driver of greenhouse gas emissions reduction, and SCE estimates that it will reduce emissions by 3.5 MMT. Other benefits include $510 million in participant bill savings, downward electric rate pressure for all electric residential customers, net peak reduction of 18 megawatts, and a natural gas reduction of 655 million therms. Fuel switching from natural gas to electricity and increased uptake of electrical appliances and heating will contribute to a sustained growth in electric power as stakeholders shift focus towards cleaner alternatives and continue to realize the economic and societal benefits of renewable energy enabled by electric infrastructure. SCE's commitment represents an immense opportunity for growth in the utilities sector, and while its building electrification program is ambitious, it only represents 15% of the potential for heat pump adoption in the service territory by 2030. This highlights the outstanding potential for heat pump efficiency within the region, increasing competition from electric utilities, and an economic growth opportunity for hybrid utilities nationwide.

Anticipating Future Policy Responses

A policy shift is already occurring in the U.S. that is leading to an acceleration of heat pump deployment and building electrification. A further policy shift is expected, consistent with the U.S. achieving its commitments under the Paris Agreement. Even in the absence of knowing this policy response with certainty, there is much that utility companies can already do to reduce emissions and it would be imprudent for gas utilities to assume that the status quo can continue.

We expect policymakers to continue advancing policies centered on electrification and efficiency, while remaining open to potential options like RNG, hydrogen, and hydrogen-derived fuels in supporting roles. Depending on the region, potential cost advantages, and high emissions reductions potential, we also expect policymakers to consider deep hybrid electrification as a viable interim option towards eventual complete decarbonization.

Research from ACEEE highlights the growing number of states that are pursuing beneficial electrification and heat pump adoption. A study conducted by RMI highlights actions across the federal, state, and local levels, with 15 states and roughly 100 cities adopting policies to encourage or require building electrification. Four key states in particular are targeting 12 million cumulative additional heat pumps by 2030. At the federal level, RMI's analysis of the Inflation Reduction Act (IRA) indicates that:

> *"Just the residential tax incentives offered in the IRA could lead to over 7 million heat pumps deployed across the country, and since the tax incentives are not capped, this is just a floor. Additionally, the High Efficiency Electric Home Rebate program in the IRA could fund another 2.5 million electrification retrofits for low- and moderate-income households."*

Gas and electric utility companies are both very capital intensive businesses and routinely make investments into very long-lived infrastructure (20 or 50 years or more) without full certainty about future policy action. While the precise details of future policy responses are unknowable across decades, companies should attempt to consider a range of possibilities and integrate the most prudent scenarios into their core planning and investment decisions. At a high level, we consider it reasonable for investors and utility companies to expect:

- Consumer uptake of existing federal (and state or local where applicable) building electrification and heat pump incentives that will likely see reduced gas distribution throughput volumes and reduced connections.
- Further policy changes at the federal, state, and local levels that incentivize or require deep emissions reductions from gas distribution consistent with the U.S. achieving its climate commitments.
- Policy combinations that favor pathways that are likely to be most economic and equitable from a multi-stakeholder perspective (including consumers and providers of capital amongst others), and those with certainty in achieving outcomes by relying on proven and efficient technologies.

Gas distribution companies that ignore these assumptions risk substantial misallocation of capital and stranded assets. For electric utilities, integrating these assumptions can ensure they are strategically well-placed to take full advantage of these major opportunities as the policy shift continues.

Section 4
Comprehensive Decarbonization Strategies

Integrated Systems and Synchronizing Electrification

Viable future decarbonization pathways are likely to prominently feature electrification but may not entirely rely on electrification. Especially through the transition phase when electric and gas grids coexist, integrated planning and operation of the grids may be optimal and have significant benefits of managing capacity needs, while optimizing costs and emissions reductions.

On the planning side, we note that Xcel Energy is already forming an Integrated System Planning team. While much of Xcel's gas service territories are in more severe climate regions where deep hybrid electrification might be appropriate, we expect integrated system planning to have benefits even in milder climate regions where complete electrification is more likely. In both cases, dual-fuel utilities should investigate electrification potential at system, circuit, and branch levels as a prerequisite before proceeding with any gas grid upgrades or life extension projects. Similarly, when planning for electric grid upgrades, it is best to future-proof these by considering multi-year electrification needs to avoid more expensive serial upgrades. In this way, deep hybrid electrification and targeted electrification should be considered and modelled in parallel.

In regions in which deep hybrid electrification is relevant, there are a range of plausible approaches to integration of system operation (with the boundaries of the 'system' in this context being the two grids, the buildings, and their appliances). More sophisticated integration could involve smart appliances and thermostats that can send and receive data and automatically respond to requests from the grid operators. The costs of upgrading to smart thermostats for existing gas, oil, and propane furnaces are low and many heat pump models already have smart capabilities embedded. For example, Vermont Gas, a gas-only utility, recently launched a new program to encourage electric heat pump adoption for its customers that will be integrated with existing gas furnaces that will serve as an auxiliary backup system to help meet extreme weather conditions. The cold climate heat pump will deliver the household primary heating need and a smart thermostat will toggle between the heat pump and gas furnace system based on outdoor temperature and specific user settings.

However, deep hybrid electrification does not need to be so sophisticated to be effective. Price signals, incentive programs, or emergency requests could encourage manual and temporary switches back to legacy fuel-based heating systems to avoid electric grid overload in particularly severe winter events.

Synchronizing Electrification – Especially Transport

It will also be important to synchronize electrification of space heating with electrification in other applications so that the costs of required capacity upgrades, if any, are diluted with greater throughput volumes. This can be particularly beneficial when these other load sources are flexible so that they can be molded around peaky hourly and daily demand profiles during major winter events. While there may be some flexibility for demand response in the industrial sector and non-space heating uses in the building sector, the transport sector likely offers the biggest opportunity for synergies. Transport energy demand can decline precipitously in the severe winter events that simultaneously cause heating needs to spike. For example, in analysis carried out by the Chicago Metropolitan Agency for Planning, between 2020 to

2022, the Illinois Department of Transportation (IDOT) data showed that traffic volumes fell 60% during a February 2022 snowstorm. Further, with the range of electric vehicles exceeding daily usage in these severe events, there is potential to shift transport load by multiple days or even weeks. In addition to charging flexibility, vehicle-to-grid (V2G) and vehicle-to-building (V2B) capabilities may be exceptionally beneficial for meeting these seasonal peak needs since the stored energy and power output of an electrified national vehicle fleet could be significant and the infrequent nature would not meaningfully degrade vehicle life.

Access, Affordability, and a Just Transition

As the current system shows, a lack of careful planning can create undue environmental burdens that adversely impact public health, degrade land and environment, and exacerbate climate change. Historically, these impacts have fallen harder on marginalized households. At the same time, a continued lack of forethought has resulted in rising energy costs (partly attributable to instability in global energy markets), avoidable job loss, and significant stranded assets as a result of underestimating climate risk and the growing shift to cleaner energy resources.

Long-term planning that integrates equity, access, and justice into core business operations is fundamental to building a viable low-carbon energy system. An equitable and accessible energy model will efficiently optimize the system to guarantee low end-use rates and make prices affordable for all customers in their region. It will effectively safeguard public health by avoiding emitting harmful pollutants into indoor and outdoor environments. It will ensure that energy is delivered in a reliable manner without detriment to any group of people, including minority or low-income households, workers, or tribes. Utilities directly benefit from this planning in a variety of ways, including cost savings from energy efficiency and consumer support for decarbonization plans, leading to faster implementation and less costly delays

The cost of energy is already a burden for a large fraction of Americans. In 2020, over a quarter of U.S. households — 27% — experienced some form of energy insecurity, and 20% of households reported forgoing food and medicine to pay for energy costs according to the EIA. Utilities should seek to maintain reliability and affordability, while simultaneously delivering on climate goals. This includes integrating resources like energy efficiency to reduce avoidable energy consumption, encouraging distributed energy resources where beneficial, and expending capital on inter- and intra-regional transmission projects to enable renewable energy sharing between energy rich regions and load centers.

Utilities should exercise prudence to ensure that customers along every step of the transition have secure, equal access to affordable energy. This will require different approaches for different groups. Tailored low-income programs will be integral to support certain households and ensure equitable access. Varying levels of income, fuel usage, housing unit types (renters vs. homeowners), and age are some of the considerations that should be taken into account when designing low-income and accessibility programs.

Adequate support should also be made available to low-to-moderate income customers for the upfront costs of electrification and other decarbonization measures so that they are not stranded on the existing fossil fuel system during the transition, as a shrinking customer base and reduced gas throughput sends costs upward. Analysis by ACEEE examined illustrative scenarios for 25%, 50%, and 75% full electrification and found that costs for remaining customers on the gas system increased between 20% - 119% depending on the scenario, compared to 315% expected in a biogas scenario.

Deep hybrid electrification in the short-to-medium term helps displace some of these large price hikes by redistributing costs over a longer time horizon, while still delivering deep carbon reductions in the same time frame. For example, integration of small ductless heat pumps paired with an existing fuel heating system can effectively reduce upfront electrification costs, and benefits from efficiency advantages and cost savings of electric heat pumps. In this way, investments support deep hybrid electrification on the eventual path to full electrification, meaningfully reduce emissions in the interim, and keep the energy transition affordable by pacing out household retrofits and capacity upgrades to the electric grid.

Equity also depends on accessibility and including stakeholders affected by the transition in decision-making around energy production, distribution, and siting, among other matters. Though gas distribution infrastructure is widely dispersed, it relies on a supply chain with concentrated impacts. Similarly, while electrification centric pathways mainly involve deploying electric appliances widely across the building stock, electrification also has an impact on the use of existing grid (and power plants) and building new electric infrastructure. Any new infrastructure that is needed or changes to existing infrastructure could adversely affect those communities. Complementary state and federal policies provide some regulatory oversight, but adherence to permitting regulation alone will not be enough to mitigate against harmful siting and construction practices. Meaningful engagement with affected stakeholders moves beyond customary notification, and utilities should consult with regional authorities and local communities to create space for affected residents and businesses to voice concerns about proposed builds. Tools such as EJSCREEN, EnviroAtlas, and the Power Plants and Neighboring Communities Mapping Tool include many demographic and suitability factors that may help equip companies and contractors to make more responsible siting decisions. Similarly, robust guardrails for procuring manufactured components and responsibly sourced natural gas across more transparent global supply chains will be beneficial.

Accessibility in the form of education is also critical to deliver a just and equitable energy system. Outreach through multi-lingual flyers, community center presentations, and local radio show announcements, for example, help empower customers to make informed decisions about their energy supply and connect them to utility program offerings that they may not have been aware of otherwise. Utilities have a crucial role to play in educating customers about the advantages of low-carbon energy options and installing electric appliances. Customer decisions have a large impact on the amount of emissions savings possible in a system, from the type of technology installed to the fuel choice, user settings, and efficiency standard options available. Utilities, contractors, and regulators should recognize the importance of customer decision-making and promote efforts that encourage knowledge-building among all customers. Investing in education is also beneficial for utilities, providing utilities with better insight into customer needs that they can use to develop more tailored programs.

Workers in the natural gas supply chain will also be impacted by the shift away from fossil-derived energy sources, and the industry has a role to play in shaping how these shifts happen by supporting workforce investment and just transitions for workers who are being displaced. The transition will provide significant potential to create decent jobs and economic opportunities for workers, and utilities would benefit from long-term planning to develop a pipeline for workers that effectively retrains and redeploys them for careers in clean energy and electrification. Not all companies will have the capacity to retain all reskilled employees but, where possible, they should be prioritized while others are prepared for demands elsewhere for the jobs being created by the growing clean economy, including electrification, efficiency, and to a smaller extent, low-carbon fuels. An estimated 580,000 – 1.08 million clean energy jobs, are expected to be created between 2020-2030 domestically (before taking into consideration job growth from electric appliance installation and the HVAC industry). The natural gas industry in 2021 employed 535,284 people domestically, with 39% (or 210,684 people) in fuel transmission and distribution. It is exceedingly important that these are quality new jobs with competitive wages and job protections, including measures like responsible contracting policies to adequately attract skilled talent and encourage local stakeholder buy-in.

Addressing Methane

Regardless of the mix of decarbonization pathway options, the U.S. gas distribution system will continue to be operational in the short- to medium-term as the industry transitions to a less carbon intensive system, and, depending on the projected reliance on low-carbon fuels, to an extent in the long term. That means that the industry will need to address methane, a potent greenhouse gas with 84 times the global warming potential of carbon dioxide in a 20-year timeframe.

Methane emissions from the gas distribution industry represent 7.6% of total U.S. methane emissions, before considering upstream emissions that are larger and under-reported. Most of the distribution industry's own emissions are attributed to outdated and leaky gas distribution pipelines. An estimated 9% of total pipeline mileage is exceedingly vulnerable to leakage due to old age and the use of brittle and leaky material (cast-iron and unprotected steel). Data collected under the Environmental Protection Agency Greenhouse Gas Reporting Program (GHGRP), estimates that total methane emissions in 2020 from distribution pipelines totaled 12.5 MMT CO_2e, however attributions to leakage indicate that emissions are likely higher. Figures from the Environmental Defense Fund Natural Gas Leakage Rate Modeling Tool highlights the uncertainties associated with current estimates of leakage in the gas supply chain, specifically local distribution, and scenario modeling helps illustrate the importance of addressing leak rates in the context of decarbonization.

Gas utilities have an opportunity to reduce their scope 1 emissions in the short term by focusing on efforts to repair and replace vintage leaky pipes. However, the scope of investment should target pipelines that demonstrate the most critical need and be balanced by the costly impact to customers and detriment to climate objectives. New investments in the existing system have the potential to exacerbate the risk of stranded assets or indirectly lock-in use of these assets beyond timetables ideal for 1.5C climate scenarios. That is why targeted long-term planning will be essential to cutting methane emissions, while simultaneously decarbonizing the entire gas distribution system.

Strategies that address gas throughput volumes, like efficiency and electrification, address carbon dioxide and upstream methane emissions simultaneously. However, since pathways for methane emissions (such as modelled by IEA) are accelerated compared to end-use emissions, additional steps need to be taken to address methane across the supply chain. These extra steps to address methane emissions should be seen as in addition to — not in place of — the primary focus of reducing end-use emissions.

MITIGATION PROGRAMS

One credible option for utilities contemplating methane mitigation and pipeline repairs and replacements is the **Oil and Gas Methane Partnership 2.0 (OGMP 2.0)**, a reporting and mitigation program stewarded by the United Nations Environment Programme (UNEP) for the purpose of providing a framework for accurate reporting. Guided by comprehensive, actionable emissions data, the program helps companies develop cost-effective mitigation strategies for their most material sources. The program holds companies accountable to setting methane reduction targets and developing implementation plans to meet those targets. In addition to using OGMP 2.0 to address their own methane emissions, utilities can leverage their significant buying power to request or require their suppliers to sign on to OGMP 2.0.

Another option is the **Natural Gas Distribution Infrastructure Safety and Modernization (NGDISM) federal grant program**, which apportions $1 billion from the Infrastructure Investment and Jobs Act in a five-year timespan to community or municipally-owned utilities to help maintain vulnerable gas distribution pipelines. The program prioritizes the highest risk, legacy pipelines, particularly in underserved communities, for the repair, replacement, or rehabilitation of leak-prone pipes. Both programs serve to reduce methane emissions from aging and leaky gas distribution systems by offering targeted support for the most material pipes. This is critical of any mitigation effort to avoid over-investment in a system that will face macroscale retirements in the coming years.

Section 5
Recommendations

We recommend that **investors**:

- Encourage multi-utility and electric utility companies to pursue decarbonization strategies in line with a 1.5°C goal, capital expenditure opportunities, and policy engagement centered on electrification and efficiency.
- Be skeptical of any utility decarbonization plans that rely on availability of substantial volumes of RNG or blending of hydrogen without an analysis of prospective costs to end consumers and availability of the fuels.
- Request detailed evidence from gas distribution and multi-utility companies of the prospective viability of their decarbonization plans at meaningful scale and its impact to customers, particularly low-income households, environmental justice households, and renters.
- Request disclosure of the underlying assumptions of gas distribution capital expenditures associated with system expansion and asset life extension, and analyses on whether these are recoverable with the prospects of significant electrification during asset lives.
- Consider directly engaging with federal and state policymakers and regulators to foster enabling economic conditions for viable decarbonization of the gas industry.

We recommend that **utility companies**:

- Develop decarbonization strategies in line with 1.5°C pathways with electrification and efficiency at the core.
- Support an appropriate policy framework that enables the company to pursue decarbonization, with electrification and efficiency at core, by ensuring that engagement with legislators, regulators, and trade associations is informed by and aligned to a 1.5°C pathway.
- Pursue integrated system planning and system operation where possible and undertake system modelling that considers varying extents of complete and deep hybrid electrification that may be regionally appropriate to optimize capacity needs and avoid cost escalation.
- Adapt expenditure plans to reflect the opportunities with electrification and efficiency, while testing the lifetime viability of capital expenditures into gas distribution against electrification-centric alternatives to avoid stranding customers and wasting shareholder resources.
- Synchronize electrification of heating, which is peaky, with electrification in other areas, with an emphasis on the complementary and flexible demand patterns of transport to dilute the financial impacts of any electric grid upgrades.
- Place consumers and communities at the center of decarbonization plans, with an emphasis on reducing the energy burden by 1) designing and targeting electrification and efficiency programs to address household incomes, homeownership status and racial equity, among other factors, and 2) pursuing strategies such as hybrid electrification to manage electric grid capacity needs to avoid cost escalation.

Appendix 1: 1.5C Alignment

Why Focus on 1.5C Alignment and not Paris Alignment?

Although the Paris Agreement has two levels of ambition (well below 2°C and ideally 1.5°C),[8] we focus on 1.5°C since the Paris Agreement was adopted in December 2015. More recent research aggregated by the IPCC and featured in the Special Report on 1.5°C published in 2018 and the AR6 Physical Science Basis report published in 2021 has emphasized the substantial differences between 1.5°C and 2°C outcomes. In comparing the two outcomes, the summary presentation on the 2018 report notes 1.5°C results in "Up to several hundred million fewer people exposed to climate-related risk and susceptible to poverty by 2050." Further, the 2021 report states: "With every additional increment of global warming, changes in extremes continue to become larger. For example, every additional 0.5°C of global warming causes clearly discernible increases in the intensity and frequency of hot extremes, including heatwaves (very likely), and heavy precipitation (high confidence), as well as agricultural and ecological droughts in some regions (high confidence)."

IPCC-featured Scenarios

In the IPCC's Mitigation of Climate Change report published in 2022, the scientific consensus on the overall direction of gas volumes at the global level is clear. For the entire global gas industry, 97 scenarios that limit warming to 1.5°C with low or no overshoot have median declines in gas volumes of 10% by 2030 and 45% by 2050 from 2019 levels (with interquartile ranges of 0% to -30% and -20% to -60% respectively). However, these are not levels that are specific to the U.S. gas distribution industry because these are a global aggregation that reflects ongoing growth in emerging markets and volumes that bypass gas distribution too, including some hard-to-avoid uses in the industrial sector.

The IPCC's 2022 mitigation report's chapter on the building sector is most relevant to the gas distribution industry since it provides a deeper dive into four specific scenarios and an aggregation of 67 underlying bottom-up studies on mitigation potential. In aggregate, these 67 studies show direct emissions from the building sector of North America declining from 594 Mt in 2020 to 257 Mt in 2050, but unfortunately these scenarios are not specific to 1.5°C outcomes. Aside from the inclusion of other North American countries, there is also an imperfect overlap between the building sector's direct emissions and the gas distribution industry due to distribution, including some of the industrial sector's volumes and buildings using multiple fuels (like propane and heating oil). Nevertheless, direct emissions of the building sector are the most relevant to the gas distribution industry since these exclude the building sector's emissions from electricity use and embodied in construction materials.

The IPCC's mitigation report's buildings chapter also features deeper dives into four scenarios, with two by the IEA and two from academic research. The two scenarios from academic research are approximately consistent with 2°C outcomes, and while providing useful analysis, are not appropriate for measuring alignment with the Paris Agreement or 1.5°C specifically.

IEA Scenarios

The IEA scenarios featured in the IPCC report include the Net Zero Emissions by 2050 (NZE) scenario and the Sustainable Development Scenario (SDS). The NZE scenario is broadly aligned with a 1.5°C outcome (with slight overshoot to 1.6°C around 2040 before declining to 1.4°C by 2100), while the SDS scenario has previously been described as "equivalent to a 50% probability of a stabilisation at 1.65 °C." In its more recent 2022 World Energy Outlook, the IEA has discontinued publishing the SDS but has updated

8 The full text of the temperature objective is: "holding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels, recognizing that this would significantly reduce the risks and impacts of climate change".

its NZE scenario alongside its Announced Pledges Scenario (APS) and Stated Policies Scenario (STEPS). The APS sees an increase to around 1.7°C by 2100 (median estimate), while STEPS sees an increase to 2°C around 2060, and increases thereafter, with a 10% chance of rising above 3.2°C in 2100.

The IEA's NZE scenario, per Figure 8 reproduced below, outlines a pathway that involves natural gas almost entirely being phased out of the building sector by 2050 through a combination of efficiency, avoided demand and behavioral change, electrification, and renewables (I.e. RNG), with only a modest role for hydrogen.

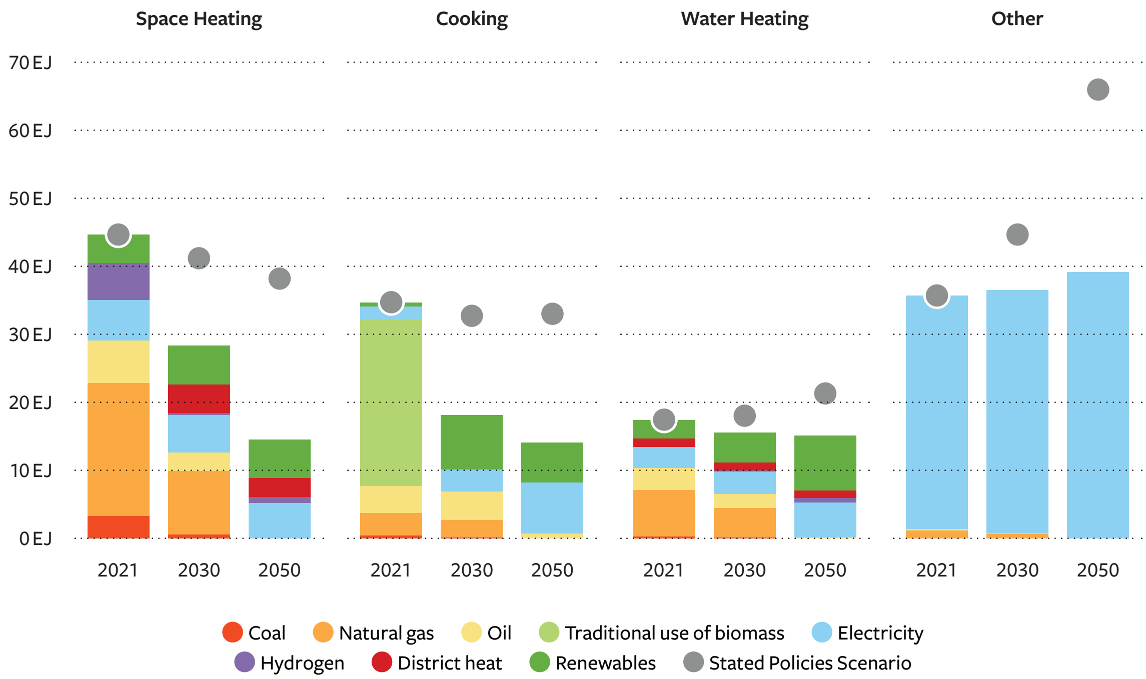


Figure 8: Total final consumption in buildings by source and end-use in the NZE scenario 2021-2050. Source: IEA Net Zero by 2050 report.

Additionally, the NZE scenario outlines that direct emissions reductions of the buildings sector at a global level would be front-loaded rather than being a straight line to 2050. Versus a 2021 base, the NZE pathway for the building sector's direct CO2 emissions is absolute reductions of 46% by 2030, 84% by 2040 and 98% by 2050 on a gross basis before adjusting for offsets. For comparison, the equivalent reductions in APS are 26% by 2030, 53% by 2040, and 66% by 2050. Modelled reductions specifically for the U.S. as a developed economy are likely to be even more accelerated, though are not disclosed publicly.

Under the GHG Protocol, gas distribution companies reported scope 3 emissions should include both upstream emissions and end use emissions, which are dominated by methane and carbon dioxide respectively. Caution needs to be used in applying the IEA's pathways for carbon dioxide above to gas utilities' combined scope 3 emissions. Notably, the IEA's NZE scenario separately features a reduction in energy-related methane emissions of 75% by 2030.