Via Commercial Overnight Delivery,
Via https: //forms.office.com/g/YOSs3UFdL3, and
Via email to: The.Secretary@hq.doe.gov; Hayes.Jones@ee.doe.gov

Sec. Jennifer M. Granholm
U.S. Department of Energy
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February 5, 2024

Re: Request for Information: National Definition for a Zero Emissions Building: Part 1 Operating Emissions Version 1.00, Draft Criteria 89 Fed. Reg. 1086 (Jan. 9, 2024)

Sec. Granholm and Mr. Marootian:

The American Gas Association (AGA) respectfully submits these comments on the Department of Energy's (DOE or Department) January 9, 2024[1], request for information and comment on the draft definition for Zero Emissions Buildings.

[1] 89 Fed. Reg. 1086. The DOE's notice improperly limited comments to the Request for Information to a list of discrete DOE determined questions and further limited comments by mandating that responses would only be accepted via an internet only list of questions that allowed commenters a limited number of characters to respond to each DOE directed question on a complex issue of national economic and policy significance. Therefore, these comments supplement the American Gas Association's responses to the internet only list of questions.

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AGA and its members are committed to improvements in energy efficiency, consumer energy affordability, access to reliable energy, and greenhouse gas emissions reductions.

AGA, founded in 1918, represents more than 200 local energy companies that deliver clean natural gas throughout the United States. There are more than 77 million residential, commercial, and industrial natural gas customers in the U.S., of which 96 percent – more than 74 million customers – receive their gas from AGA members. AGA advocates for natural gas utility companies and their customers and provides a broad range of programs and services for member natural gas pipelines, marketers, gatherers, international natural gas companies, and industry associates. Today, natural gas meets more than one-third of the U.S. energy needs.[2]

Natural gas pipelines are an essential part of the nation's energy infrastructure. Indeed, natural gas is delivered to customers through a safe, approximately 2.7-million-mile underground pipeline system, including 2.3 million miles of local utility distribution pipelines, 100,000 miles of gathering lines, and 300,000 miles of transmission pipelines providing service to more than 189 million Americans.

Distribution pipelines are operated by natural gas utilities or "local distribution companies (LDCs)." The gas utility's distribution pipes are the last critical link in the natural gas delivery chain that brings natural gas from the wellhead to the burner tip. AGA member utilities are the "face of the gas industry," embedded in the communities they serve, and interact daily with customers and the state regulators who oversee pipeline safety locally. The distribution industry takes very seriously the responsibility of continuing to deliver natural gas to our families, neighbors, and business partners as safely, reliably, and responsibly as possible.

The American Gas Association is committed to reducing greenhouse gas emissions through smart innovation, new and modernized infrastructure, and advanced technologies that maintain reliable, resilient, and affordable energy service choices for consumers. Policy should recognize that improving energy

[2] For more information, please visit www.aga.org.

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efficiency in residential, commercial, industrial, transportation, and other natural gas applications is a cornerstone strategy for reducing greenhouse gas emissions.

As our nation pursues ambitious decarbonization goals, the U.S. gas utility industry is committed to providing the solutions required to achieve a sustainable energy future. AGA supports policies and regulatory changes at the state and federal level, identifies the investments necessary to deploy and scale advanced technologies, and supports actions essential to help companies and communities successfully develop and implement effective and feasible decarbonization strategies. The use of gas decarbonization strategies can accelerate the deployment of emission reduction technologies, keep energy delivery systems resilient and reliable, and deliver the affordable energy that Americans need.

AGA supports efforts to reduce greenhouse gas emissions through efficiency and greenhouse gas-focused codes and standards that are fuel-neutral, utilize full-fuel-cycle metrics, and are technologically feasible, economically justified, and follow statutory requirements. The definition should recognize the benefits of using natural gas and emerging fuels in achieving ***net*** zero emissions. Gas is a clean, abundant, and the preferred form of energy used by a large percentage of the United States population, and to exclude it as a foundational element to the future of energy would be imprudent and in violation of DOE’s authority delegated by Congress.

DOE should reconsider its approach to ensure alignment with the Energy Policy and Conservation Act, foster consumer choice, and preserve access to today’s cost-effective technologies and options and tomorrow’s innovations. The proposed Zero Emission Building definition conflicts with the broader goal of achieving 'net-zero' greenhouse gas emissions, as outlined by the President.

AGA is concerned about the practicality and feasibility of the proposed definition. The removal of entire categories of onsite energy sources would severely limit the ability of buildings to quickly and cost-effectively reduce emissions consistent with net-zero pathways. DOE should establish a definition that is ultimately achievable.

Moreover, DOE's proposed definition lacks robust analytical backing. Under the

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proposed definition, essential options like pipeline gas and other fuels would be excluded from the building sector's future solutions. Furthermore, emerging technologies, particularly those involving carbon capture, storage, and utilization at the building site, would be ineligible under the DOE's current proposal despite their potential contributions. The proposed definition could disincentivize onsite equipment needed for energy reliability.

There is substantial evidence in current research that demonstrates a long-term role for pipeline gas and other fuels in achieving ambitious environmental goals including decarbonization and net-zero emissions by mid-century. In November 2023, GTI Energy's 'Designs for Net-Zero Energy Systems' report, a meta-analysis of U.S. economy-wide decarbonization studies, concluded that pipeline gas and liquids remain integral in all building sector scenarios achieving net-zero emissions by 2050. Further analysis indicates that integrating Renewable Natural Gas (RNG) could be a more feasible and cost-effective solution for many consumers than solely relying on all-electric pathways for zero net greenhouse gas emissions.

Any definition should be inclusive of fundamental tenets such as building safety, affordability, reliability, resilience, and practicality of implementation. Furthermore, any definition should encompass a spectrum of local, state, and regional factors, such as climate variability, diverse consumer bases (including commercial and industrial buildings), building stock characteristics, renewable energy potential (spanning electricity, gases, and other fuels), energy system impacts, consumer equity and preferences, technological maturity, anticipated technological advancements, requisite implementation support, and regional and state policy frameworks.

Reaching Net-Zero Emissions Requires Full-Fuel Cycle Energy Efficiency Analysis

EPA is on record for its Energy Star building program that "EPA has determined that source energy is the most equitable unit of evaluation for comparing different buildings to each other.[3] Source energy represents the total amount of raw fuel

[3] https://www.energystar.gov/buildings/benchmark/understand_metrics/source_site_difference

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that is required to operate the building. It incorporates all transmission, delivery, and production losses. By taking all energy use into account, the score provides a complete assessment of energy efficiency in a building.

In 2011, the U.S. Department of Energy (DOE) issued a "Statement of Policy for Adopting Full-Fuel-Cycle Analysis into Energy Conservation Standards Program" which states that DOE will use full-fuel cycle measures of energy use and emissions when evaluating energy conservation standards for appliances, following the recommendation of the National Academy of Sciences.[4] By the same logic, full-fuel-cycle analysis should be applied to the zero emissions building definition.

Full-fuel-cycle metrics should be used in any definition for net-zero emissions building, which may be applied to building codes and appliance standards or to evaluate the energy and environmental impact of building fuels and appliances. Policies that require evaluation of technology and fuel options must incorporate a comprehensive methodology, such as full-fuel-cycle metrics, to maximize energy efficiency and greenhouse gas (GHG) emission reductions and to ensure that users of the DOE's building definition have access to the full range of options to reduce emissions.

Full-fuel-cycle energy is the energy consumed by an appliance, system, or building. It includes energy consumed in the extraction, processing, and transport of primary fuels such as coal, oil, natural gas; energy losses in thermal combustion in power-generation plants and the energy associated with electric generation from hydroelectric power plants, wind, solar, and other sources; and energy losses in transmission and distribution to the building site. Full-fuel-cycle, therefore, includes the total energy consumption and environmental impacts of end-use energy decisions. A full-fuel-cycle-based emissions analysis should be used when the focus is on environmental objectives.

Site measurement methods – a calculation of the energy consumed at the end-use point (in the building) – do not adequately or equitably account for the total energy consumed nor emissions when more than one energy source is used in an

[4] 76 Fed. Reg. 51281 (Aug. 18, 2011)

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appliance (such as a gas furnace or boiler) or when comparing the consumption and emissions of different fuels that can be used for the same application (such as water heating or combined heat and power).

In addition, site measurement does not account for the energy lost and GHG emissions created throughout the extraction, processing, transportation, conversion, and distribution of energy to the building. Site energy alone cannot serve as the basis for a zero-emissions building definition if the goal is to reduce the consumption of primary energy resources attributable to the design and operation of the building and to lower GHG emissions.

The current site-based energy emissions analysis for buildings in the draft definition only accounts for energy used and emissions at the point of consumption or site and, therefore, only measures the emissions of the building envelope. Site energy measurement alone cannot define a zero-emission building nor affect the definition's environmental goals.

Building on their proven track record of reducing greenhouse gas emissions, natural gas providers are committed to reducing greenhouse gas emissions through smart innovation, new and modernized infrastructure, and advanced technologies that maintain reliable, resilient, and affordable energy service choices for consumers. With direction and guidance from policymakers and regulators, the natural gas utility industry continuously invests in modernizing the nation's natural gas delivery infrastructure to distribute safe, reliable, efficient, cost-effective, and sustainable energy to consumers.

As companies continue to modernize natural gas infrastructure and connect homes and businesses to the system, new opportunities arise to achieve low-cost GHG emissions reductions by leveraging new and existing natural gas infrastructure, advanced technologies, and the nation's abundant natural gas resources. Additionally, natural gas infrastructure can be used for renewable energy storage and the delivery of renewable gases derived from biogenic sources and zero-carbon electricity. The gas system's ability to integrate high-value sources of energy like renewable natural gas and hydrogen is a critical component of our nation's ability to reach ambitious greenhouse gas reduction goals.

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In February 2022, AGA published a study titled "*Net-Zero Emissions Opportunities for Gas Utilities*"[5] ("AGA's Net-Zero Study") to provide a comprehensive and rigorous analysis demonstrating the multiple pathways that exist to reach a net-zero future and the role natural gas, gas utilities, and delivery infrastructure will play in advancing decarbonization solutions. The study presents a national-level approach that leverages the unique advantages of gas technologies and distribution infrastructure and the foundational role of natural gas energy efficiency. The study underscores the range of scenarios and technology opportunities available as the nation, regions, states, and communities develop and implement ambitious emissions reduction plans. The key findings in the study include:

- Pathways that utilize natural gas and the vast utility delivery infrastructure offer opportunities to incorporate renewable and low-carbon gases provide optionality for stakeholders, help minimize customer impacts, maintain high reliability, improve overall energy system resilience, and accelerate emissions reductions.

- The ability of natural gas infrastructure to store and transport large amounts of energy to meet seasonal and peak day energy use represents an important and valuable resource that needs to be considered when building pathways to achieve net-zero GHG emissions goals.

- Continued utilization of natural gas and the vast utility delivery infrastructure can increase the likelihood of successfully reaching net-zero targets while minimizing customer impacts.

- The U.S. can achieve significant emissions reductions by accelerating the use of tools available today, including high-efficiency natural gas applications, renewable gases, methane reduction technologies, and enhanced energy efficiency initiatives.

[5] "Net-Zero Emissions Opportunities for Gas Utilities," AGA, February 8, 2022, available at aga-net-zeroemissions-opportunities-for-gas-utilities.pdf (last visited February 5, 2024). The study is appended at Attachment A ("AGA's Net-Zero Study").

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- Large amounts of renewable and low-carbon electricity and gases and negative emissions technologies will be required to meet an economy-wide 2050 net-zero target.

- Supportive policies and regulatory approaches will be essential for natural gas utilities to achieve net-zero emissions.

Natural gas and its direct use in homes and businesses has been a cornerstone of America's energy economy for more than a century and will be needed in the future. Today, hundreds of millions of Americans rely on natural gas to heat their homes, power their businesses, and manufacture goods. An emphasis on climate change and reducing emissions has complemented the natural gas utility industry's focus on safety and reliability and enabled a steep decline in methane emissions. These commitments continue, and as our nation moves towards a lower-carbon economy and embraces new fuels and technologies, the natural gas utilities are ready to meet these changes and will remain foundational to the country's future.

The Zero Building Emissions Definition Must Be Fuel-neutral and Based on Total Emissions

The Department's zero emissions building definition must be fuel neutral and based on the total emissions of a building, not merely the building envelope. As illustrated in the section above, a fuel-neutral approach maximizes the electric and gas systems to achieve efficiency, cost-effectiveness, and reliable GHG reductions for the building sector.

A fuel-neutral approach would permit flexibility and allow the inclusion of different energy sources, such as renewable natural gas, and hydrogen. In addition, a fuel-neutral approach permits the use of existing infrastructure while minimizing the impacts created by a fuel-neutral approach. There are many circumstances in which the use of on-site natural gas can help reduce a building's energy consumption.

A building can be designed to reduce overall energy consumption through a variety of techniques. For instance, a building can add more insulation or more efficient windows to increase the overall efficiency of the building and, therefore, reduce consumption (regardless of the energy source). Under the current

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proposal, building designers are essentially required to cut all gas appliances and energy reflexively used to meet the definition. The proposal would result in a decrease only in on-site consumption, even at the expense of a building consuming more energy overall.

The decision to disregard off-site energy consumption produced with conventional fuels is contrary to the definition's environmental goals. It fails to consider an important aspect of the problem it is trying to solve. Decreasing only on-site conventional fuel-generated energy consumption of buildings would not increase the overall energy efficiency of the buildings. It would not result in a reduction of harmful environmental emissions. Exchanging conventional fuel-generated energy for reliance on the electric grid, which may still be generating energy with conventional fuels, doesn't necessarily lead to a reduction in GHG emissions.

To argue otherwise, the Department must assume that the nation will have a zero-emissions electric grid in the future. However, the Department needs to explain the basis for this assumption, and when or how it assumes that the transition will take place.

The Department Should Fully Consider the Potential Impacts of the Proposal on the Entire Energy System and Customers

The current proposed definition would effectively only be met using all-electric applications. The Department should fully consider the impacts of any definition that stipulates only one energy source and what the implications of policy-driven electrification would mean for energy consumers and the broader energy system, including electric generation, transmission, and distribution.

In 2018, AGA engaged a cross-functional team of experts to evaluate policy-driven electrification of the U.S. residential sector. While not directly addressing buildings, the study, "Implications of Policy-Driven Residential Electrification,"[6] appended as Attachment B, identified numerous challenges to policies, such as those proposed by the Department, including:

[6] "Implications of Policy-Driven Residential Electrification," (July 2018), available at https://www.aga.org/researchpolicy/resource-library/implications-of-policy-driven-electrification/ (last visited February 5, 2024).

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- Cost-effectiveness
- Consumer impacts
- Transmission capacity constraints on the existing electrical system
- Current and projected electric grid emissions levels
- Requirements for new investments in the power grid to meet new growth in peak generation demand during winter periods.

The study finds that a policy targeting widespread electrification of the U.S. residential sector would result in only a tiny fraction of greenhouse gas emissions reductions, could be financially burdensome to consumers, could have profound impacts and costs on the electric sector, and could be a very costly approach to emissions reductions. Specifically, the study notes that the U.S. Energy Information Administration projects that by 2035, direct residential natural gas use will account for less than 4 percent of total greenhouse gas emissions, and the sum of natural gas, propane, and fuel oil used in the residential sector would account for less than 6 percent of total greenhouse gas emissions. The study concludes that reductions from policy-driven residential electrification would reduce greenhouse gas emissions by 1 to 1.5 percent of U.S. greenhouse gas emissions in 2035. The potential reduction in emissions from the residential sector would be partially offset by an increase in emissions from the power generation sector, even in a case where all incremental generating capacity is renewable. Furthermore, the study found that policy-driven electrification would increase the average residential household energy-related costs (amortized appliance and electric system upgrade costs and utility bill payments) of affected households by $750 to $910 per year, or about 38 percent to 46 percent.[7]

Additionally, the impacts of fuel switching on the reliability and resilience of the energy system must be thoroughly examined. The Department should comprehensively and systematically consider the challenges and unknown factors of comprehensive building sector electrification as they pertain to the proposal.

AGA's Net-Zero Study discussed the challenges and unknown factors related to building sector electrification. AGA's Net-Zero Study at 42-44. While careful

[7] The study did not assess the incremental costs required to expand the electric distribution system.

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analysis is required to understand the full extent of any challenges in a specific region, electrifying buildings can spur additional infrastructure costs if it's necessary to increase available generating capacity and upgrade the electricity grid to meet a new peak in electricity demand. Adding significant levels of electric space heating often shifts the electric grid from summer peaking to winter peaking. Many local power distribution grids would require substantial upgrades to handle the additional load from comprehensive building electrification. In addition to implications on the electric system infrastructure, electrification of residential and commercial buildings can have potentially costly ramifications or technical limitations that will impact current gas customers. For example, retrofitting commercial buildings in major urban centers can be extremely difficult.

Some additional factors that will affect the impact of building electrification include:

- The region's existing generation capacity and outlook for new generating capacity coming online.

- The region's adoption rate of EVs, how much that will shift energy demand from gasoline to electricity, and whether there are policies and incentives in place to change EV charging out of peak demand periods.

- The efficiency of the building stock in a region. The cost of all forms of energy is expected to go up in pursuit of carbon-neutral targets. Energy efficiency is often the least expensive strategy and, therefore, should be the first action taken in many cases. Before pursuing building electrification, the Department should prioritize and incentivize energy efficiency upgrades, such as building envelope upgrades.

- Natural gas distribution systems design. Natural gas distribution systems are designed to provide service reliably with a plan to serve firm customers without disruption during peak winter periods, often called a "design day." Winter load fluctuations (the difference between a peak design day and an average winter day) tend to be much higher than fluctuations in summer loads, creating additional challenges associated with reliability. It is critical to understand the expected performance of end-use equipment on peak cold days when air source heat pumps may rely on electric resistance back-up and to understand electric system requirements to meet design day peak demand for electrified end uses.

- Decommissioning costs. Most decarbonization studies have not addressed the cost of decommissioning the gas system if all customers were to electrify fully.

The challenges and opportunities for electrification will also depend on the scale, speed, and sectors being electrified. Not all forms of electrification will have the exact costs or impacts, and some gas uses, like space heating, will pose a particular challenge to electrification.

The Department's Definition Should Fully Embrace the Use of Renewable Gases and Hydrogen

The Department should revise the proposal to ensure that it supports the current and future use of renewable gases and hydrogen in buildings. The Department should provide the greatest amount of flexibility possible for achieving emission reductions. AGA strongly supports expanding access to renewable gases in an effort to accelerate widespread accessibility and adoption of renewable and low-carbon energy sources. The natural gas system can store and deliver renewable energy derived from various sources and is a critical tool for reaching GHG reduction goals.

Many AGA members have already begun demonstrating their commitment to integrating renewable gases into their existing pipeline networks. To date, at least fifteen AGA member companies in the United States have established or are in the process of developing voluntary renewable natural gas ("RNG") program offerings for their customers, also referred to as "green tariffs" for retail service. Many gas utilities have begun investing in RNG to lower their gas throughput emissions and to offer customers a low-carbon and renewable energy option. AGA closely tracks all state legislative and regulatory actions nationwide related to the use of RNG in the building sector, and activity has increased significantly over the last several years. Over twenty-eight states across the United States have

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taken some form of action to promote the use of renewable gas in the residential or commercial sector. Moreover, dozens of gas utilities now have experience blending RNG into their pipelines, and many are working to deliver RNG to their customers. Furthermore, utility investment in hydrogen is increasing, from piloting hydrogen production technologies to evaluating the impacts on direct-use gas equipment. Beyond technical engagement, many gas utility companies have begun to incorporate hydrogen into their emission reduction strategies while educating policymakers, regulators, and customers on their plans for a hydrogen-enabled gas system. The development of these program offerings is a direct reflection of growing customer demand for renewable energy sources and gas utilities' continued commitment to reducing GHG emissions.

Due to the environmental benefits of renewable gases, the Department should ensure that such gases are fully leveraged to achieve decarbonization goals for buildings. Moreover, using RNG and hydrogen in the existing gas distribution system could mitigate the need to site, permit, and build electric infrastructure near federal buildings. RNG use can also increase the resilience of the energy system by providing a locally sourced supply of clean energy. As the Department is aware, permitting, approving, and building energy infrastructure projects is a complex task. The Department should seek ways to utilize existing natural gas infrastructure and not assume that the siting and permitting of an expanded electric transmission grid needed to replace the gas system would be any more straightforward than the current approval process for natural gas facilities. An efficient alternative is to maximize existing pipeline infrastructure and permit the expansion of RNG and hydrogen over time to achieve carbon emissions reduction goals.

Gas infrastructure and RNG can be a force multiplier for decarbonization. The use of renewable natural gas can accelerate emissions reductions and achieve greater overall emissions reductions beyond what simply volumetric measures of RNG adoption might suggest. For example, the use of dairy manure as a feedstock for renewable natural gas can achieve negative lifecycle (full-fuel-cycle) greenhouse gas emissions when accounting for feedstock collection and processing, transmission, and combustion. Because of the net-negative lifecycle greenhouse gas emissions, blending by volume 20% of renewable natural gas

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from a dairy manure feedstock into a natural gas pipeline can achieve 69% greenhouse gas emissions reductions.

As part of its analysis, the Department should contemplate future scenarios where the gas system incorporates lower-carbon fuels, such as RNG and hydrogen.

An Absolute Zero Building Emission Definition is Beyond the Department's Authority to Promulgate and In Conflict With the Department's Delegated Authority under the Energy Policy Conservation Act

The authority under which the proposed definition is promulgated, its purpose within the Department's delegated authority, and users or regulated community are not provided in the Federal Register Notice. Nor is the regulations.gov platform that the Office of Energy Efficiency and Renewable Energy routinely uses to comply with the Administrative Procedure Act referenced. As proposed, it is an ultra vires act of the Department, in violation of the Administrative Procedure Act, and must be withdrawn.

Congress has not delegated the Department with discretionary authority to address building greenhouse gas emissions, and the Department has failed to advance arguments in the administrative record that a zero emissions building definition will advance any Congressionally authorized authority or mandate.

Rather, a promulgating a zero-emissions building definition is in conflict with its delegated authority to develop federal "minimum" efficiency standards for products "covered" by the Energy Policy Conservation Act of 1975 and its amendments[8] (collectively, "EPCA"). A definition eliminating all building emissions is not only contrary to the Department's authority under EPCA, but it also places any state or municipality which may adopt it in violation of EPCA, which prohibits promulgation of efficiency standards that differ from federal minimum efficiencies.

EPCA was first passed in 1975 to create a comprehensive energy policy to address the serious economic and national security problems associated with our nation's continued reliance on foreign energy resources.

[8] Energy Policy Conservation Act of 1975 (Pub.L. 94-163, 89 Stat. 871).

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Since 1975, Congress has amended EPCA several times. Each amendment to EPCA further emphasized the federal government's intent to regulate appliance energy use and efficiency, and further limited states' abilities to set their own standards.

In 1978, Congress passed the National Energy Conservation and Policy Act ("NECPA"). NECPA amended the 1975 EPCA and required DOE to prescribe minimum energy efficiency standards for certain products. NECPA also strengthened the preemption provisions in EPCA, allowing state regulations that were more stringent than federal regulations *only* if the Secretary found there was a significant state or local interest to justify the state's regulation and the regulation would not unduly burden interstate commerce.

In 1987, Congress passed the National Appliance Energy Conservation Act ("NAECA"). The purpose of the NAECA amendment was "to reduce the regulatory and economic burdens on the appliance manufacturing industry through the establishment of national energy conservation standards for major residential appliances."[9]

Thus, NAECA contained "two basic provisions:" "[t]he establishment of Federal standards and the preemption of State standards."[10] "In general, these national standards would preempt all State standards."[11]

While states could seek permission to establish their own standards, "achieving the waiver is difficult."[12] It would require showing an unusual and compelling local interest, and the waiver could not be granted if the "State regulation is likely to result in the unavailability in the State of a product type or of products of a particular performance class, such as frost-free refrigerators."[13]

[9] S. Rep. No. 100-6, at 1 (1987).
[10] S. Rep. No. 100-6, at 2 (1987).
[11] *Id.*
[12] S. Rep. No. 100-6, at 2 (1987).
[13] *Id.*

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In 1992, Congress amended EPCA once more through the Energy Policy Act of 1992. That amendment expanded the federal appliance program to include energy efficiency standards for commercial and industrial appliances as well as consumer appliances. Thus, in its present form, EPCA covers both consumer and commercial/industrial appliances, and it sets federal standards for the energy use and efficiency of those products.

Rather than allowing joint regulation by states and the federal government, Congress has adopted a framework for EPCA in which the federal government sets nationwide standards for the national markets for appliances, with only a very limited role for states.

In fact, EPCA expressly preempts state regulation of appliance energy use and efficiency, with only narrow exceptions. The statute sets out specific requirements that must be met to qualify for one of these narrow exceptions. In other words, Congress meant to preempt the entire field of energy use by covered appliances, leaving DOE to set nationwide standards and establishing detailed conditions that state regulations must meet to avoid preemption.

EPCA's energy efficiency and use regulations apply to "covered products." EPCA defines "covered products" for consumers as the types of products listed in Section 6292 of the Act.[14] Section 6292 in turn lists 19 types of defined covered products, including "water heaters" and "furnaces."[15] Section 6295 sets out the energy conservation standards for these covered products.

EPCA defines a "consumer product" as one "(A) which in operation consumes, or is designed to consume, energy . . . and (B) which, to any significant extent, is distributed in commerce for personal use or consumption by individuals[.]"[16]The definition of a consumer product is "without regard to whether such article of such type is in fact distributed in commerce for personal use or consumption by an individual . . . ."[17] In other words, products which are regularly sold to individuals may be classified as consumer products, regardless of whether a

[14] 42 U.S.C. § 6291(2).
[15] *Id.* § 6292(a).
[16] *Id.* § 6291(1).
[17] *Id.*

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particular *unit* of the product has been purchased by an individual or by a business.

The express preemption in EPCA's consumer product regulations states that:

> effective on the effective date of an energy conservation standard established in or prescribed . . . for any covered product, no State regulation concerning the energy efficiency, energy use, or water use of such covered product shall be effective with respect to such product unless the regulation

falls within certain enumerated exceptions.[18]

"Energy use" is defined as "the quantity of energy directly consumed by a consumer product at point of use . . . ."[19] "Energy" is defined as "electricity, or fossil fuels."[20]

Thus, EPCA's consumer standards preempt state regulations concerning the quantity of electricity or fossil fuels consumed by appliances (including water heaters and furnaces) which are regularly sold to individuals. Similarly, EPCA also governs the energy efficiency and energy use of certain commercial and industrial appliances.[21]

Like EPCA's consumer standards, the industrial standards explicitly "supersede any State or local regulation concerning the energy efficiency or energy use of a product for which a standard is prescribed or established" in the federal statute.[22]

"Energy use," for the purposes of the industrial standards, is defined as "the

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[18] *Id.* § 6297(c).
[19] *Id.* § 6291(4).
[20] *Id.* § 6291(3).
[21] *Id.* § 6311-17.
[22] *Id.* § 6316(b)(2)(A).

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quantity of energy directly consumed by an article of industrial equipment at the point of use. . . ."[23] The definition of "energy" refers back to the definition in the consumer standards in Section 6291: energy is "electricity, or fossil fuels."[24]

EPCA also prescribes standards for various types of "industrial equipment," including "commercial package air conditioning and heating equipment," "warm air furnaces," and several types of water heaters.[25] Those products are "industrial" rather than "consumer" if they are "distributed in commerce for industrial or commercial use" to "any significant extent," and do not qualify as consumer products under that portion of the statute.[26]

Thus, EPCA's standards for consumer products and industrial equipment preempt state and local regulations concerning the quantity of electricity or fossil fuels consumed by heating equipment, water heaters, and furnaces which are regularly sold for residential, industrial, or commercial use.

As a result, EPCA preempts any application of the proposed zero building emissions definition by states or municipalities because these sections concern the quantity of fossil fuels consumed by EPCA-covered gas space and water heating appliances which are regularly sold for residential, commercial, and industrial use.

Any application of the proposed definition of zero building emissions concerns the quantity of natural gas consumed by appliances in the buildings that states and municipalities regulate because in many instances they prohibit the installation of EPCA-covered products. As a result, they require that *no* natural gas is used by such products, or effectively result in the use of no natural gas by such products.

Stated another way, the proposed definition of a zero emissions building effectively require that the quantity of natural gas used in certain covered products is zero, when the national standards promulgated by DOE specify levels

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[23] *Id.* § 6311(4).
[24] *Id.* §§6311(7), 6291(3).
[25] *Id.* § 6311(2)(B).
[26] *Id.* § 6311(2)(A).

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of energy efficiency that are based on different, non-zero levels of gas use by covered products.

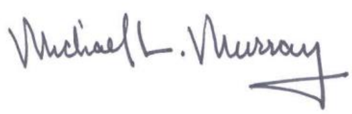
Commercial businesses and residential consumers must be able to maintain their right to choose efficient, affordable, and reliable direct use of natural gas as an energy source for their home. The proposed zero emission building definition explicitly and intentionally prioritizes one energy source over another. This places jurisdictions that may adopt the definition in violation of the Energy Policy and Conservation Act.

Conclusion

The American Gas Association respectfully requests that the Department of the Energy consider these comments in this proceeding and not implement the proposed zero emissions building definition as proposed for the reasons stated herein. If you have any questions regarding this submission, please do not hesitate to contact the undersigned.

Dated: February 5, 2024, at Washington, District of Columbia.

Respectfully submitted,



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Attachments:

Attachment A – Net-Zero Emissions Opportunities for Gas Utilities, AGA, February 2022

Attachment B – Implications of Policy-Driven Residential Electrification, AGA, July 2018

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ATTACHMENT A

Net-Zero Emissions Opportunities for Gas Utilities, AGA, February 2022

Net-Zero Emissions Opportunities for Gas Utilities

An American Gas Association Study
prepared by ICF

LETTER FROM AGA

Climate change is a defining challenge for our country and across the globe. As businesses, communities, and governments focus on reducing greenhouse gas emissions, every sector of the economy will need to make not just pledges, but progress.

America's gas utilities have consistently provided solutions to our nation's most pressing energy needs and environmental goals, and they have crucial and enduring roles as the country advances ambitious greenhouse gas emissions reductions goals. Energy is the backbone of our economy and our quality of life, and the natural gas system will be central to our energy future. Natural gas provided 34 percent of all energy consumption in the U.S. during 2020. More than 187 million Americans use natural gas in their homes every day, and the industry added nearly 900,000 new residential customers in 2020, the largest increase since 2006. That equates to one new customer every minute and 21,000 new business customers each year. Investments in the natural gas system support well-paying jobs, power our nation's industries, fuel economic growth, improve air quality, support communities, and reduce pollution.

In 2020, on behalf of the nation's natural gas utility industry, the American Gas Association issued its "Climate Change Position Statement." It made 10 collective commitments toward achieving a significantly lower-carbon energy economy. Since that time, the industry has doubled down on its innovation and investment, driving increased progress and reimagining our energy future. These substantive efforts build on the progress already underway—gas utility industry methane emissions have decreased 69 percent since 1990, and the use of natural gas for power has enabled the expansion of renewables and led to carbon dioxide emissions in the sector reaching three-decade lows. And the industry is not done yet.

To further advance our emissions reductions, I am pleased to present *Net-Zero Emissions Opportunities for Gas Utilities*. It provides a comprehensive and rigorous analysis demonstrating the multiple pathways that exist to reach a net-zero future, and the role natural gas, gas utilities and delivery infrastructure will play in advancing decarbonization solutions. There is no single pathway to a net-zero economy, and planning must consider highly localized factors like geography, energy demands, resources, and weather. The study presents several pathways to underscore the range of scenarios and technology opportunities available as the nation, regions, states, and communities develop and implement ambitious decarbonization plans.

Recognizing the critical benefits of gas industry infrastructure and the energy choices it provides can help us better leverage all of the resources and tools required to innovate toward the energy system of the future. This industry is advancing practical solutions today and making investments that bring considerable advantages to meet the country's energy goals and achieve our ambitious emissions reductions goals well into the future.

Industry and government must work together to advance innovative policies, scale-up and deploy new technologies and invest in reliable and resilient infrastructure. Only through an integrated approach to decarbonization that leverages the advantages of the gas distribution system can we realize a reliable and resilient energy future that minimizes negative impacts for customers.

As our nation pursues ambitious decarbonization goals, the U.S. gas utility industry is committed to providing the solutions required to achieve a sustainable energy future. AGA will continue to develop and advance the supportive policies and regulatory changes needed at the federal and state levels, identify the investments necessary to deploy and scale advanced technologies, and support actions essential to help companies and communities successfully develop and implement effective decarbonization strategies. We can accelerate the deployment of emission reduction technologies, keep our system resilient and reliable, and still deliver the affordable energy that Americans need.

We look forward to the work and collaboration ahead to continue the course to a cleaner energy future.

Karen Harbert
President and Chief Executive Officer
American Gas Association

IMPORTANT NOTICE

This is an American Gas Association (AGA) Study. The analysis was prepared for AGA by ICF. AGA defined the cases to be evaluated and vetted the overall methodology and major assumptions. The EIA 2021 AEO Reference Case, including energy prices, energy consumption trends, and energy emissions, was used as the starting point for this analysis.

This report and information and statements herein are based in whole or in part on information obtained from various sources. The study is based on public data on energy and technology cost and performance trends, and ICF modeling and analysis tools to analyze the emissions impacts for each study case. Neither ICF nor AGA make any assurances as to the accuracy of any such information or any conclusions based thereon. Neither ICF nor AGA are responsible for typographical, pictorial or other editorial errors. The report is provided AS IS.

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ABSTRACT

In recognition of the need to address climate change, a growing number of jurisdictions and businesses are announcing goals to achieve deep decarbonization with an increasing focus on meeting net-zero emissions targets within the next three decades. The American Gas Association commissioned ICF to conduct an in-depth assessment of opportunities for gas utilities to support these ambitious goals. The analysis examined the greenhouse gas emissions associated with utility operations, gas production and transportation emissions, and utility customer emissions created by the direct use of natural gas in the residential, commercial, industrial, and transportation sectors.

This study finds that through the use of a variety of technologies and approaches, gas utilities can achieve net-zero emissions targets and contribute to economy-wide net-zero emissions goals. Further evaluation of these emission reduction opportunities and their ability to support tenets aligned with safety, affordability, reliability, resilience, and feasibility criteria will be an important part of developing and implementing decarbonization strategies. Community and customer benefits beyond greenhouse gas emissions reductions, such as reduction in air pollution, increased economic development, and consumer energy savings, may also be realized and are not reflected in this analysis. To be successful, any pathway to achieve net-zero emissions—including those not assessed in this study—will require the support of policymakers, regulators, and customers, along with investment into infrastructure and emerging technologies.

Given the importance of natural gas and gas infrastructure in the current U.S. economy, this analysis shows that gas utilities can play crucial and enduring roles in building economy-wide pathways to achieve a net-zero greenhouse gas emissions future. Pathways that utilize gas infrastructure offer opportunities to incorporate renewable and low-carbon gases, provide optionality for stakeholders, help minimize customer impacts, maintain high reliability, improve overall energy system resilience, and accelerate emissions reductions. The ability of gas infrastructure to store and transport large amounts of energy to meet seasonal and peak day energy use represents an important and valuable resource that needs to be considered when building pathways to achieve net-zero greenhouse gas emissions goals.

ICF analyzed various emission reduction technologies/options for gas utilities and worked with the AGA to develop several illustrative pathways that showcase how different combinations of these solutions can be designed to achieve net-zero emissions. The approaches examined include managing energy demand by expanding energy efficiency and promoting emerging technologies, supplying renewable and low-carbon fuels, reducing emissions from gas utility operations and pipelines, and utilizing negative emissions technologies. The study presents national-level results, dependent on a wide range of assumptions. The preferred mix of measures will ultimately vary by region and utility. Further analysis that accounts for highly localized considerations, including costs and impacts on consumers, communities, and the economy, will be needed to study these and other pathways for a given area or gas utility service territory.

The challenge of meeting net-zero emissions goals should not be understated. Reaching economy-wide net-zero emissions targets will require transformational changes in producing, transporting, storing, and consuming energy (gas, electricity, and other forms). All options should be on the table to ensure a cost-effective, reliable, resilient, and equitable transition to a net-zero emissions energy system, and gas and electric utilities both have roles to play to support this transition. Expanded research, development, and deployment support are vital to achieving these targets. Nonetheless, this study demonstrates the many opportunities and solutions for gas utilities to help their customers and communities address climate change and accelerate strategies to achieve net-zero emissions goals.

EXECUTIVE SUMMARY

Climate change is one of the defining challenges of our time. Addressing climate change will require fundamental changes in energy use and reducing greenhouse gas (GHG) emissions throughout the economy.

The Intergovernmental Panel on Climate Change has indicated that deep reductions in greenhouse gas emissions will be necessary to mitigate the largest risks of climate change, and that economy-wide net-zero emissions are needed by 2050 in order to limit global warming to 1.5°C (in line with the Paris Agreement).[1] As a result, municipalities, states, and the federal government have committed to clean energy or greenhouse gas reductions with an increasing focus on meeting net-zero emissions targets within the next three decades. In addition, many businesses—including natural gas utilities—have announced clean energy or emission reduction commitments. But clear pathways to these goals are still unknown. The starting point in any climate policy discussion should be the consideration of all potential greenhouse gas emission reduction tools.

As policymakers and businesses consider strategies to meet economy-wide net-zero emissions targets, many stakeholders have sought to mandate electrification of consumer end-uses. Often these approaches have been pursued without a robust evaluation of the associated challenges or risks, or considering and assessing the decarbonization opportunities across the natural gas value chain.

This report provides an in-depth assessment of four illustrative pathways that rely on gaseous fuels and gas infrastructure to achieve net-zero greenhouse gas emissions by 2050. Although the specific pathways differ significantly in approach, all encompass expanded energy efficiency initiatives, a shift to renewable and low-carbon fuel supplies, reduced emissions from gas operations and pipelines, carbon offsets, and negative emissions technologies.

This report is not intended to provide a precise roadmap for gas utilities to follow.

Instead, it illustrates the potential for gas technologies and infrastructure to support deep reductions in GHG emissions and highlights the need to consider these opportunities in all planning for net-zero pathways.

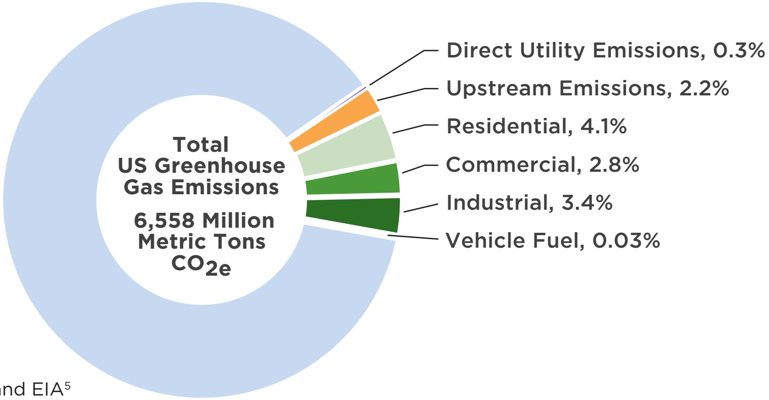
1 *Climate Change 2021: The Physical Science Basis*, the Intergovernmental Panel on Climate Change, 2021: https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_Full_Report.pdf

Greenhouse gas emissions related to gas utilities can be considered in three separate categories[2]:

- **Direct gas utility emissions**
- **Customer emissions (residential, commercial, industrial, and vehicle fuel) from the onsite combustion of gas**
- **Upstream gas emissions from the production and transportation of gas purchased from utilities**

As shown in **Exhibit E.S. 1**, 2019 greenhouse gas emissions associated with gas utilities represented less than 13% of total US emissions.[3] Of those, customer emissions comprise the bulk of overall emissions linked to gas utilities. The ability of gas utilities to help their customers reduce these emissions will be critical to reaching economy-wide net-zero targets. Much of the analysis in this study focuses on pathways to reduce customer emissions, but separate opportunities and pathways are also presented for direct utility and upstream emissions categories.

Exhibit E.S. 1 – Total 2019 US Greenhouse Gas Emissions and GHG Emissions Categories Associated with Gas Utilities[3]



Source: EPA[4] and EIA[5]

To be successful, all pathways to achieve net-zero emissions will require the support of policymakers, regulators, and customers, along with significant investment into infrastructure and emerging technologies. Reaching net-zero emissions targets will require transformative changes to our energy systems and will have cost and other implications for consumers (a full consideration of which is outside the scope of this study). Nonetheless, this study suggests that there are crucial and enduring roles that gas utilities and gas infrastructure can play when building pathways to achieve a net-zero emissions future. In particular, decarbonization pathways that leverage both the gas and electric systems have a greater potential to help minimize negative customer impacts, maintain high reliability, accelerate carbon reductions, improve overall energy system resiliency, and create opportunities for emerging technologies (such as power-to-gas and hydrogen) to support the needs of both systems in a net-zero future.

The following sections discuss each of these topics in more detail.

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2 The World Resources Institute and World Business Council for Sustainable Development (WRI/WBCSD) have established widely adopted GHG measurement and tracking protocols. These protocols separate corporate emissions for reporting companies into three categories or "Scopes." This report avoids the scope terminology in an attempt to make the content easier to comprehend by a broad audience. However, the three gas utility GHG emissions categories discussed here do generally fall into the scope categories as well. Direct natural gas utility emissions are Scope 1 emissions. For gas utilities, customer emissions from the onsite combustion of gas sold by the company are Scope 3 emissions. Customer emissions from combustion of gas delivered but not sold by utilities are not included in Scope 3 but are sometimes included in this analysis. For gas utilities, upstream emissions from the production and transportation of gas they sell are also Scope 3 emissions. Scope 2 emissions related to electricity consumed by the gas utility are not included here but are typically negligible relative to the Scope 1 or 3 emissions, and would be mitigated as electricity generation shifts to net-zero.

3 The GHG emissions associated with gas utilities shown here do not include any combustion or upstream emissions for natural gas use by the electricity generation sector, or for natural gas that is not delivered by gas distribution companies (e.g., not all industrial natural gas demand is delivered by gas utilities). Total US GHG emissions are from EPA's latest ***Inventory of U.S. Greenhouse Gas Emissions and Sinks*** covering emissions in 2019. Customer emissions are calculated based on LDC delivered volumes share of national gas consumption in 2019 based on EIA-176 reporting. Direct utility emissions include methane and CO2 emissions, based on the EPA inventory and methane GWP of 25. Upstream emissions are calculated based on volumes delivered to customers captured here and an average emissions factor of 11.3 kg CO2e/Mcf.

4 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2019 – Main Text - Corrected Per Corrigenda, Updated 05/2021 (epa.gov)

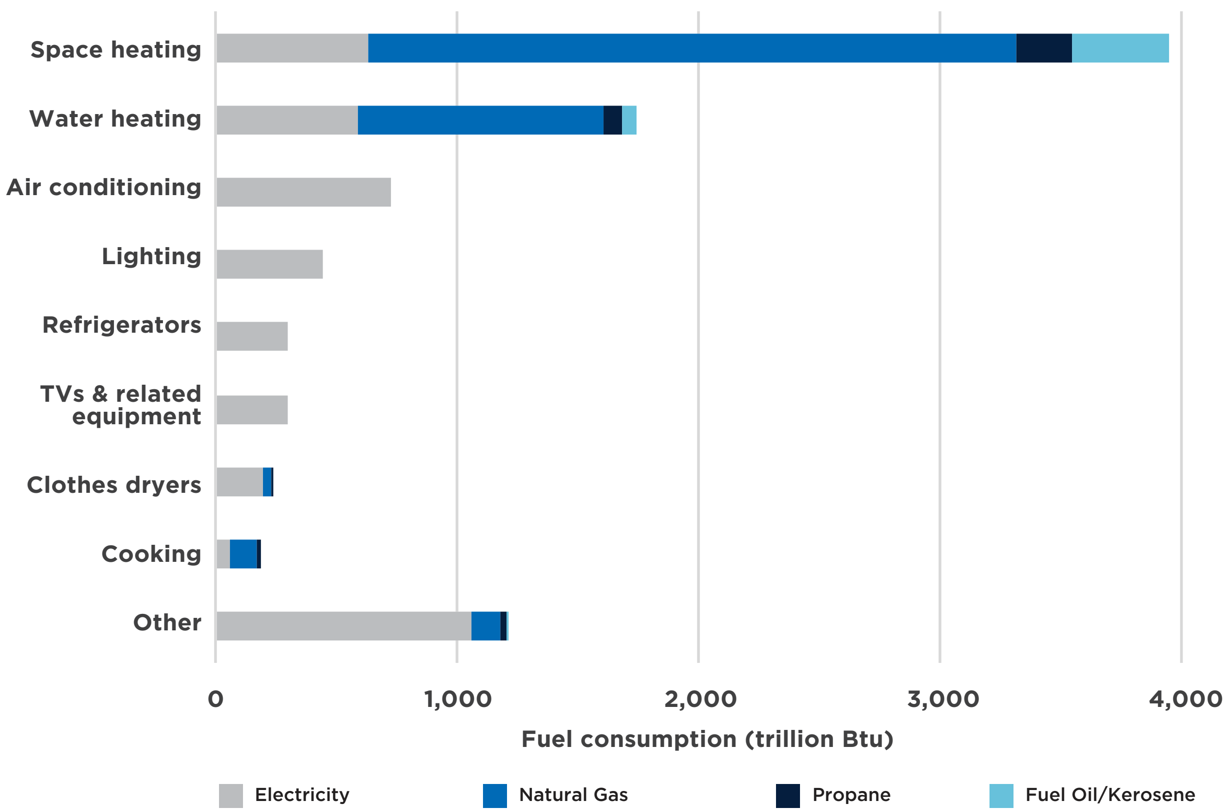
5 https://www.eia.gov/dnav/ng/ng_cons_sum_a_EPG0_vgt_mmcf_a.htm

Gas utilities and gas infrastructure can play crucial and enduring roles when building pathways to achieve a net-zero emissions future

Natural gas is a core component of the U.S. energy system, and customers and policymakers value it for its affordability, flexibility, reliability, and resiliency. **More than fifty percent of American households currently use natural gas as a heating fuel, and reliance on gas is even higher in many colder regions.** Natural gas dominates space and water heating consumption in residential households, as shown in **Exhibit E.S. 2**, and it is also widely used in commercial and industrial facilities. The scale of the U.S. economy's dependence on natural gas highlights the crucial role for gas infrastructure on any pathway to net-zero greenhouse gas emissions by 2050, and the need to address associated carbon dioxide and methane emissions. Additionally, the ability of gas infrastructure to store and transport large amounts of energy to meet seasonal and peak day energy use represents an important and valuable resource that should not be ignored when building pathways to achieve net-zero greenhouse gas emissions goals.

Based on the analysis presented in this report, there is a range of pathways to net-zero greenhouse gas emissions utilizing the gas system. An integrated approach to decarbonization that leverages the advantages of the gas distribution system is likely to support a more effective, reliable, and resilient transition to a net-zero energy system that minimizes negative impacts for customers.

Exhibit E.S. 2 – U.S. Household End-use Energy Consumption by Fuel (trillion Btu)



Source: EIA 2015 Residential Energy Consumption Survey

Using a range of different approaches and technologies, gas utilities can meet net-zero GHG emissions targets, and the appropriate mix of measures will vary by region and utility

For this report, ICF worked with AGA to develop illustrative pathways to net-zero emissions combining different technologies and approaches to emission reductions. In particular, ICF and AGA focused on opportunities to reduce greenhouse gas emissions within gas utilities' purview, including utility operations, gas production and transportation, and the direct use of natural gas by utility customers across the residential, commercial, industrial, and transportation sectors. This study finds that through the use of a variety of technologies and approaches, gas utilities can achieve net-zero emissions targets and contribute to economy-wide net-zero emissions goals.

At a high level, the emission reduction strategies for gas utilities included in this report can be separated into four general categories, shown in **Exhibit E.S. 3**. The first approach is to reduce gas demand; the second is to decarbonize the gas supply required to meet the remaining demand; the third is to reduce utility system and upstream emissions from methane leaks; and the fourth is to use negative emissions technologies to offset remaining GHG emissions. These strategies can largely be employed simultaneously, and the relative priority of individual approaches will vary by region and utility.

A wide range of existing and emerging energy efficiency and gas equipment and supply options have potential to contribute to decarbonization goals.

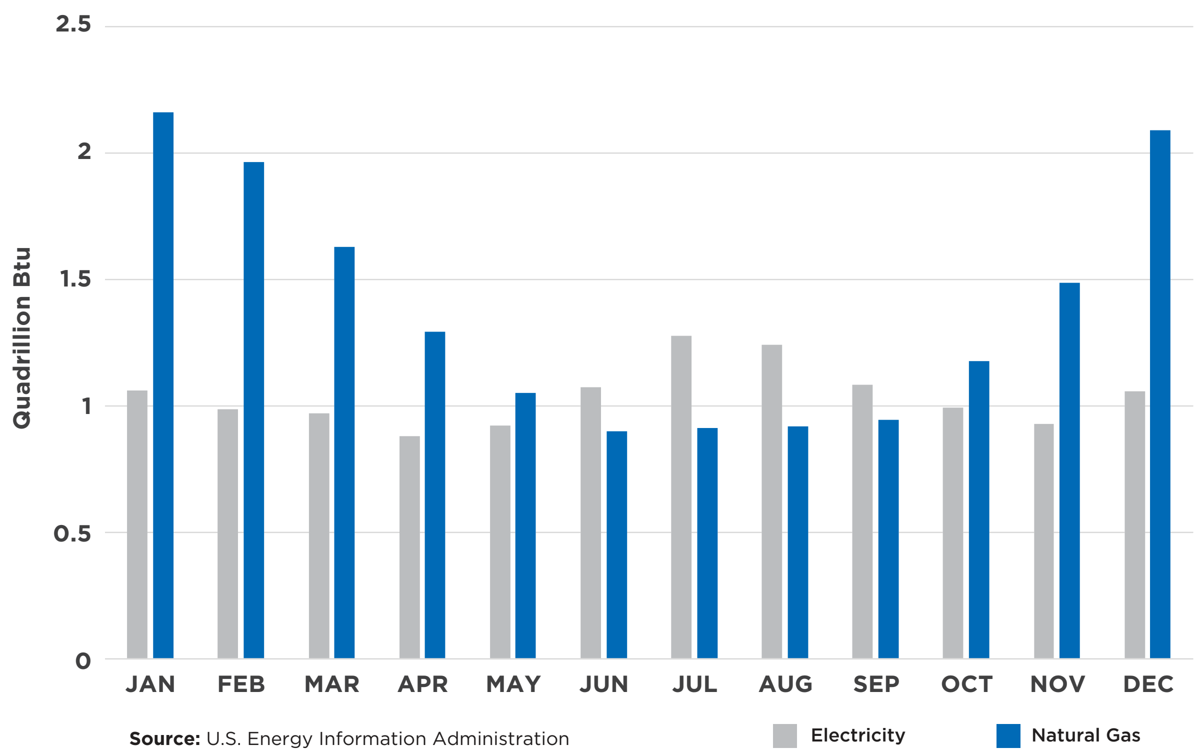
Exhibit E.S. 3 - Examples of Gas Utility Approaches to Reducing Emissions

The ability of gas infrastructure to store and transport large amounts of energy to meet seasonal and peak day energy use represents an important and valuable resource that needs to be considered when building pathways to achieve net-zero greenhouse gas emissions goals

Many of the discussions and analyses looking at net-zero emissions targets begin from the assumption that mandated electrification of all fossil fuel uses, including all uses of natural gas, will be required (along with a shift to a net-zero emissions electric system), and that most, if not all, of the existing natural gas distribution infrastructure will need to be phased out. However, because a relatively limited amount of robust and comprehensive decarbonization scenario analysis that includes natural gas decarbonization strategies has been completed to date, policymakers and other key stakeholders should conduct more analysis that considers the value of natural gas decarbonization strategies or the potential risks of a limited decarbonization approach that focuses exclusively on electrification of all sectors of the economy.

One important factor to consider in any comprehensive decarbonization scenario analysis is that the peak energy demand currently served by natural gas is significantly higher than that of the electrical system in most regions. The primary reason is that most locations in the US have higher heating loads than cooling loads, as measured through heating or cooling degree days.[6] The existing gas energy storage and delivery infrastructure was designed to reliably serve customers through spikes in consumption driven by space heating during cold winter periods, while the electric infrastructure was generally designed for lower levels of peak demand (driven mainly by summer air conditioning loads). **Exhibit E.S. 4** compares total monthly electricity and gas demand in the U.S. The demand differential between gas and electricity is even more pronounced when looking at the peak day or the peak hour instead of monthly averages

Exhibit E.S. 4 – 2020 US Electric and Natural Gas Consumption Across all Customer Sectors



Source: U.S. Energy Information Administration

6 *November 2021 Monthly Energy Review*, US Energy Information Administration, 2021: https://www.eia.gov/totalenergy/data/monthly/pdf/mer.pdf

As a result of this differential in peak demand between gas and electricity, it's likely that a large-scale shift to electric heating—even using highly-efficient technology such as air-source heat pumps—would drive significant increases in peak electric loads, shift the electric grid from summer peaking to winter peaking in many locations, and increase the challenges associated with decarbonizing electric generation using intermittent renewable sources. While careful analysis is required to understand the full extent of any challenges in a specific region, electrification could spur additional infrastructure costs if it necessitates an increase in available generating capacity and electricity grid upgrades to meet a new peak electricity demand. As demonstrated by the 2021 cold snap in Texas, energy infrastructure needs to be built to accommodate such peaks—even if very cold periods are infrequent.

Leveraging renewable and low carbon gas for heating and other uses can help bolster decarbonization while maintaining high levels of energy system reliability with regards to building heating needs. More broadly, continued utilization of gas infrastructure can bring flexibility to future energy systems and could make net-zero pathways more feasible for the electric grid. One possible example is hybrid gas-electric heating systems, which provide space heating through the use of an electric air-source heat pump paired with a natural gas furnace and utilize integrated controls that optimize the energy consumption, emissions and cost of the system throughout the year. Hybrid heating can help provide many of the decarbonization benefits of all-electric heat pumps (or even offer additional flexibility benefits on days with low renewable generation by switching to gas heating) while reducing high winter electric peaks, maintaining heat reliability for customers, and helping to maintain lower energy bills during cold periods. It should be noted that the hybrid heating opportunity would also create operational and cost challenges for gas utilities (accommodating similar peak demand while annual demand declines), and may require a much different regulatory paradigm. Leveraging gas and electricity in decarbonization plans could also help alleviate other challenges associated with an electrification-only approach, particularly the logistical and cost issues that utilities and others face in comprehensively retrofitting existing buildings (across all sectors). Emerging strategies such as hydrogen and power-to-gas may also help enable natural gas infrastructure to be used for renewable energy storage, providing a potentially compelling long-duration energy storage solution for variable renewable energy and helping the power sector add more renewables.

Some regional factors may pose challenges for wide-scale building electrification, particularly if gas isn't included as part of the overall decarbonization plan. These include:

- Limits on the region's existing electric supply capacity and the outlook for new capacity coming online. New renewable energy resources combined with energy storage baseload capacity offer a viable path to serve increased demand from electrification while reducing carbon emissions. Although renewable electricity resources like solar and wind have become relatively inexpensive, storing power from those intermittent resources remains expensive. While declining battery storage prices support shifting renewable power to different hours of the day, replacing dispatchable fossil fuel generation and storage capacity is particularly challenging for long duration seasonal or reliability requirements (for example, having multiple days of stored electricity to cover periods of low renewable generation).
- The region's adoption rate of electric vehicles (EVs), how much (and how quickly) that will shift energy demand from gasoline to electricity, and whether there are policies and incentives in place to sufficiently shift EV charging out of peak demand periods. Both vehicle and building electrification can stress the distribution grid—and create peakier, less-predictable power demand—so

measures should be taken to avoid these increases in electric load occurring at the same time and in the same places when possible, and add new infrastructure to manage them as needed.

- The efficiency of the building stock in a region. The cost of all forms of energy is likely to go up in pursuit of net-zero emissions targets. Energy efficiency is often the most cost-effective emissions-reduction strategy and in many cases should be the first action taken. As a result, it may make sense to prioritize and incentivize energy efficiency upgrades, such as building envelope upgrades, before pursuing building electrification. Older, less efficient buildings may also pose additional hurdles to electrification due to increase costs, complexity of retrofits, and need for upgraded electrical service.

The challenges and opportunities for electrification will also depend on the scale, speed, and sectors being electrified. Not all forms of electrification will have the same costs or impacts, and some gas end uses like space heating are likely to pose a particular challenge to electrify. Pathways that leverage decarbonization strategies across both the gas and electric system may have potential to better maintain low energy costs, improve system reliability, create opportunities for emerging technologies (such as power-to-gas and hydrogen) to support the needs of both systems, accelerate carbon reductions, and improve overall energy system resiliency.

Planning for a net-zero future should not necessitate a choice between one energy system or another energy system (gas, electricity, or other forms). Leveraging the gas and electricity systems for their relative strengths should allow for a lower-risk pathway to reducing emissions.

Continued utilization of gas infrastructure can increase the likelihood of successfully reaching net-zero targets while minimizing customer impacts

Any pathway to net-zero emissions will require transformative changes to multiple energy systems and the economy as a whole, and will face a number of significant emergent challenges (both expected and unexpected). However, some decarbonization pathways are likely to be more feasible to implement, appealing to customers, and have a higher chance of success. All of the emissions reduction options need to be considered and, where viable, deployed in net-zero emissions pathways in order to maintain flexibility, decrease the chances of energy systems failing, maintain or increase existing public support for aggressive climate action, and increase the chances of reaching net-zero targets. Pre-selecting 'winning' technologies for 2050 or making decisions to shut down some energy systems that customers across all sectors currently rely on will reduce the role that innovation can play in supporting emissions reductions, and may make it more difficult and expensive to achieve net-zero emissions goals.

The table in **Exhibit E.S. 5** outlines the four pathways included in this analysis and highlights the primary emission reduction measures in each pathway. These pathways are meant to be illustrative of the kinds of combinations of emission reduction strategies that could be pursued and they are not intended to be prescriptive. Many other pathways combining emission reduction strategies differently could also be possible, and this study does not attempt to establish an 'optimized' pathway. Particularly given the diverse array of measures available, the optimal pathways for a specific region and utility will vary based on highly localized factors, such as climate/temperatures, energy prices, the composition of the housing stock, and commercial and industrial base, as well as the capacity, age and GHG intensity of existing electricity generation, transmission, and distribution infrastructure. The other decarbonization pathways adopted in a given area, including for sectors outside the scope of this work (e.g., power generation[7] and transportation), as well as the speed of change, will also impact the optimal pathway for a given region.

Each of the four pathways studied reaches net-zero emissions for the gas utility and gas utility customers by 2050. The pathways discussed in this report combine a number of different measures to reach net-zero emissions targets, and **Exhibit E.S. 6** summarizes how each of these pathways leads to gas utility customer emission reductions. The color bands represent the emission reductions achieved relative to a baseline 'Business as Usual' (BAU) case, showing the diversity of strategies included in each pathway to net-zero emissions. The relative portion of 2050 savings between reductions in gas demand, renewable and low carbon gas supply, renewable and low carbon gas supply, and negative emissions technologies are indicated to the right.

7 While gas demand in the power sector was not included in this analysis, the study assumed that greenhouse gas emissions from electricity generation would be net-zero by 2050; this is a critical assumption that drives the logic for several of the measures explored in the different pathways.

Exhibit E.S. 5 – Illustrative Gas Customer Decarbonization Pathways

Pathway		Description	Key Strategies
1	**Gas Energy Efficiency Focus**	This pathway is designed to help maintain customer fuel choice by leveraging existing infrastructure, demand-side management programs, and regulatory structures. It drives emission reductions primarily through the significant expansion of utility energy efficiency programs, promotion of gas heat pump technology, building shell retrofits, more stringent fuel-neutral building energy codes, and considerable volumes of renewable and low carbon gases.	• Gas heat pumps • Aggressive fuel-neutral building energy codes • Major building shell retrofits • High-efficiency gas appliances • Other energy efficiency (E.E.) measures • RNG & hydrogen blending • Negative emissions technologies
2	**Hybrid Gas-Electric Heating Focus**	This pathway focuses on coordinated gas and electric infrastructure planning and optimization through widespread adoption of hybrid gas-electric integrated heating systems, as well as selective electrification of certain end uses (with the goal of avoiding additional stress on the electric grid where possible), in conjunction with a large push for more gas energy efficiency. Greater coordination, and hybrid heating systems specifically, will require new regulatory structures to accommodate, but may also offer the potential to achieve a more optimized energy system (eg. controlling hybrid systems to respond to real-time signals like low levels of wind or solar generation).	• Hybrid gas-electric heating • Improved fuel-neutral building energy codes • Building energy efficiency retrofits • High-efficiency gas appliances • Electric appliances • Other E.E. measures • RNG & hydrogen blending • Negative emissions technologies
3	**Mixed Technology Approach**	This pathway represents an “all of the above” scenario with fuel-neutral policy where customers choose from a range of applications. Rather than focusing primarily on a single technology or a single energy system, this pathway illustrates a wide range of technologies to reach emission reduction targets such adoption of gas heat pumps, a ramp-up in utility efficiency programs, hybrid heating technologies, and some electric applications.	• Hybrid gas-electric heating • Gas heat pumps • Electric air-source heat pumps • Improved fuel-neutral building energy codes • Building energy efficiency retrofits • High-efficiency gas appliances • Electric appliances • Other E.E. measures • RNG & hydrogen blending • Negative emissions technologies
4	**Renewable and Low Carbon Gas Focus**	This pathway prioritizes the decarbonization of the energy supply in order to limit the need for customers to make major changes in energy equipment and infrastructure. It relies heavily on existing and emerging renewable and low carbon fuels and less on aggressive retrofits of the building stock. This pathway still includes significant levels of gas energy efficiency improvements.	• Improved fuel-neutral building energy codes • Building energy efficiency retrofits • High-efficiency gas appliances • Gas heat pumps • Other E.E. measures • RNG & hydrogen blending • Dedicated hydrogen infrastructure • Negative emissions technologies

As with any complex forward-looking projection incorporating a wide array of data inputs, these pathways depend on a range of assumptions. First, the analysis in this study shows the possibility to develop more RNG than previous estimates developed by ICF for the 2019 American Gas Foundation study on RNG. This study relied on the same resource potential as the 2019 study but reflected a 10 year longer timeline, as well as changes in expectations regarding the achievable share of the resource potential (see **Section 4.4.1** for further details). Second, all the pathways studied in this analysis are built off a range of key assumptions from the U.S. Energy Information Administration's (EIA) 2020 Annual Energy Outlook (AEO) reference case forecast, which assumes roughly 25% natural gas customer growth between 2020 and 2050. This built-in expectation of customer growth shows how, under the right conditions, gas utilities can continue to be critical parts of future energy mixes while still enabling and supporting a shift to a net-zero economy. Because more emphasis was placed on developing pathways showcasing a diversity of options to meet 2050 targets—rather than optimizing all technologies included in a given scenario or trying to reach interim milestones—this study does not attempt to predict what is most likely to happen by 2050. Finally, the results of this study are presented at the national level; further analysis accounting for highly localized considerations (including costs) will be needed to study these and other pathways for a given region.

The gas utility customer GHG emissions for each of the four pathways are shown in **Exhibit E.S. 6**. The customer emissions shown in this exhibit represent more than 80% of overall gas utility-related GHG emissions. Pathways to reduce the remaining roughly 20% of emissions, reducing the direct utility and upstream GHG emissions to net-zero levels, are also covered in the full report.

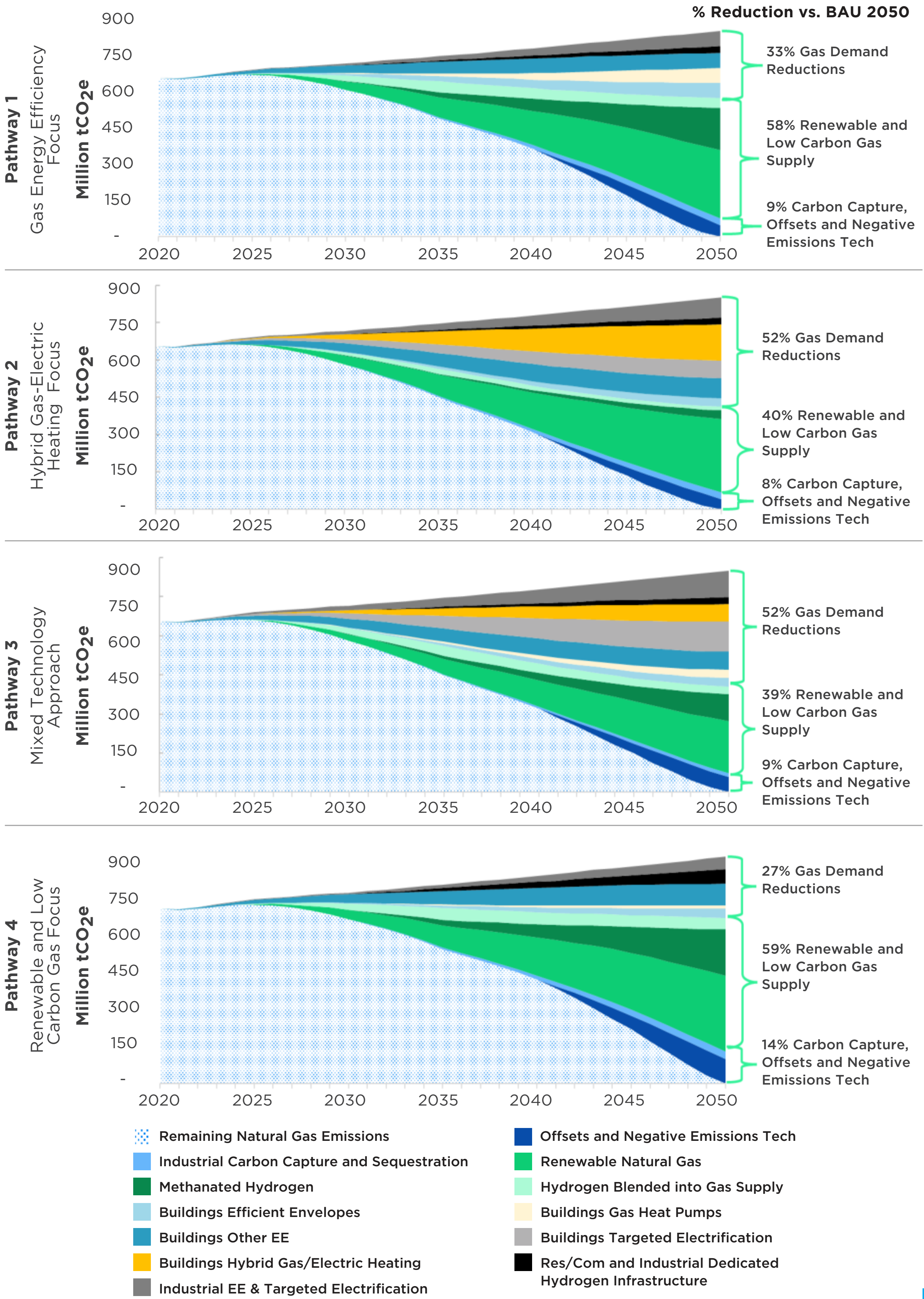
Gas utilities can achieve significant emission reductions by pursuing immediate actions like expanded energy efficiency, renewable fuels, and methane emissions mitigation

Improvements in energy efficiency are typically the lowest-cost approach to reducing emissions and can have a significant impact while also offering a range of benefits to customers (from reduced bills to increased comfort). According to 2020 AGA research, natural gas utilities helped customers save 259 trillion Btu of energy and offset 13.7 million metric tons of carbon dioxide emissions from 2012 through 2018 in the US.[8] In a different 2020 report from Lawrence Berkeley National Laboratory, researchers found an average overall levelized program cost of saved natural gas of $0.40/therm across nearly 37 different utilities/program administrators in 12 states over six years.[9] That level of cost-effectiveness is difficult to match through non-efficiency approaches to gas demand reduction, and it underscores the importance of energy efficiency in any successful decarbonization plan. Many of the energy efficiency measures that gas utilities can promote, such as smart thermostats or building insulation retrofits, also promote customer choice since they can support decarbonization pathways using both electric and gas end uses.

8 *Natural Gas Efficiency Programs Report 2018 Program Year*, American Gas Association, 2020: https://www.aga.org/globalassets/aga-ngefficiency-report-py2018-5-2021.pdf

9 *Cost of Saving Natural Gas through Efficiency Programs Funded by Utility Customers: 2012–2017*, Lawrence Berkeley National Laboratory, 2020: https://escholarship.org/uc/item/0164134n

Exhibit E.S. 6 – U.S. Gas Utility Customer Emission Reduction Pathways

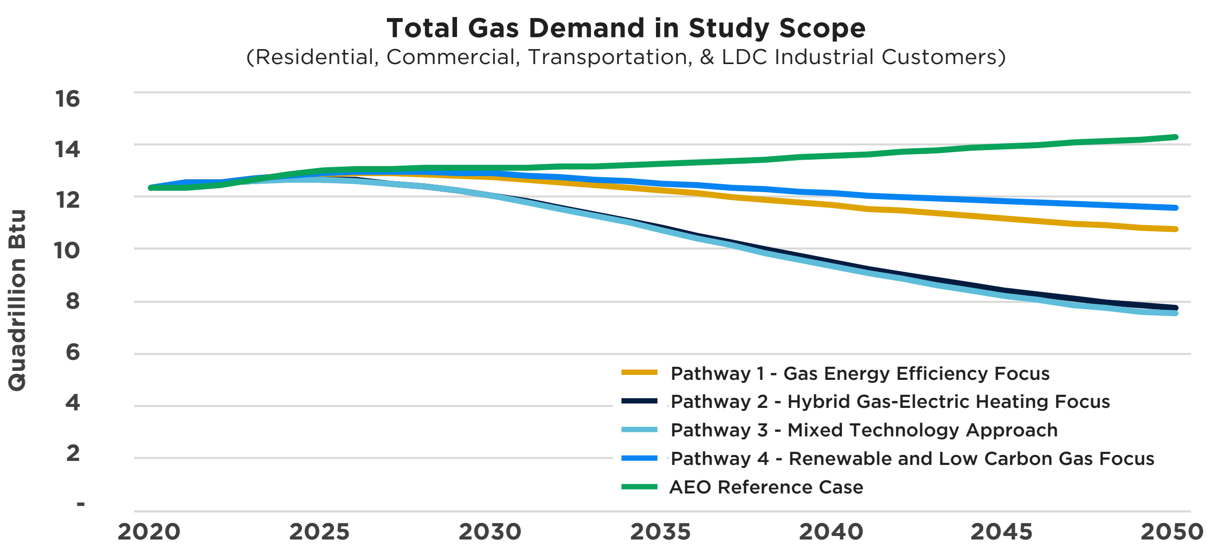


Any pathway to net-zero emissions will also require significant increases in renewable and low carbon gas, and all of the production that can be brought on-line will likely be needed. Gas utilities could help aggressively develop these resources in the coming years (taking a parallel approach to electric utilities that are working to develop emissions-free electricity quickly). Finally, more accurate quantification and reduction of methane leaks is also a key strategy for reducing GHG emissions. However, more precise and company-specific methane emissions factors will likely be needed to capture direct utility emissions more accurately and help utilities prioritize and track leak reductions.

While all pathways show an overall decline in customer gas demand by 2050, the degree of gas demand decline depends upon the unique set of emission reduction solutions deployed in each pathway. The line graph in **Exhibit E.S. 7** shows the changes in gas demand over time modeled in each of the four pathways studied in this report. The table in the exhibit shows the percent change in gas demand from 2020 in 2050, split by the different utility customer sectors. Overall, the pathways studied here would reduce utility customer gas demand by between 6% and 39% from 2020 levels, or between 22% and 55% from 2050 AEO Reference Case levels. The smallest reductions in gas demand come from pathways that rely more heavily on renewable gases.

The pathways studied in this analysis are built on key assumptions from the U.S. EIA AEO reference case forecast, which assumes natural gas customer growth of roughly 25% between 2020 and 2050. As a result, the demand reductions shown below would be significantly larger without the growth in the customer base predicted by the AEO Reference Case, and less renewable and low carbon fuel would be needed to meet customer needs in a lower demand scenario.

Exhibit E.S. 7 – Total Gas Demand for U.S. Gas Utility Customers[10] in Each Pathway



2050 VS 2020 % Change

	Total	Res	Com	Ind	Transp
AEO Reference Case	+16%	-3%	+13%	+32%	+413%
P4 - Renewable & Low Carbon	-6%	-9%	-5%	-13%	+413%

2050 VS 2020 % Change

	Total	Res	Com	Ind	Transp
P1. Gas EE Focus	-13%	-23%	-11%	-11%	+413%
P2 - Hybrid Heating	-37%	-54%	-46%	-19%	+413%
P3 - Mixed Approach	-39%	-52%	-44%	-29%	+413%

10 Utility customer gas demand only. Utility industrial demand assumed to represent half of total industrial gas use, while this chart also does not capture natural gas for power generation.

Large amounts of renewable and low-carbon electricity and gases, and negative emissions technologies, will be required to meet an economy-wide 2050 net-zero target

As in the power sector, rapid and widespread adoption of renewable, low-carbon, and negative emissions resources will be essential to the gas sector achieving net-zero emissions. All pathways included in this study incorporate a significant expansion of renewable natural gas (RNG) and hydrogen production and consumption.

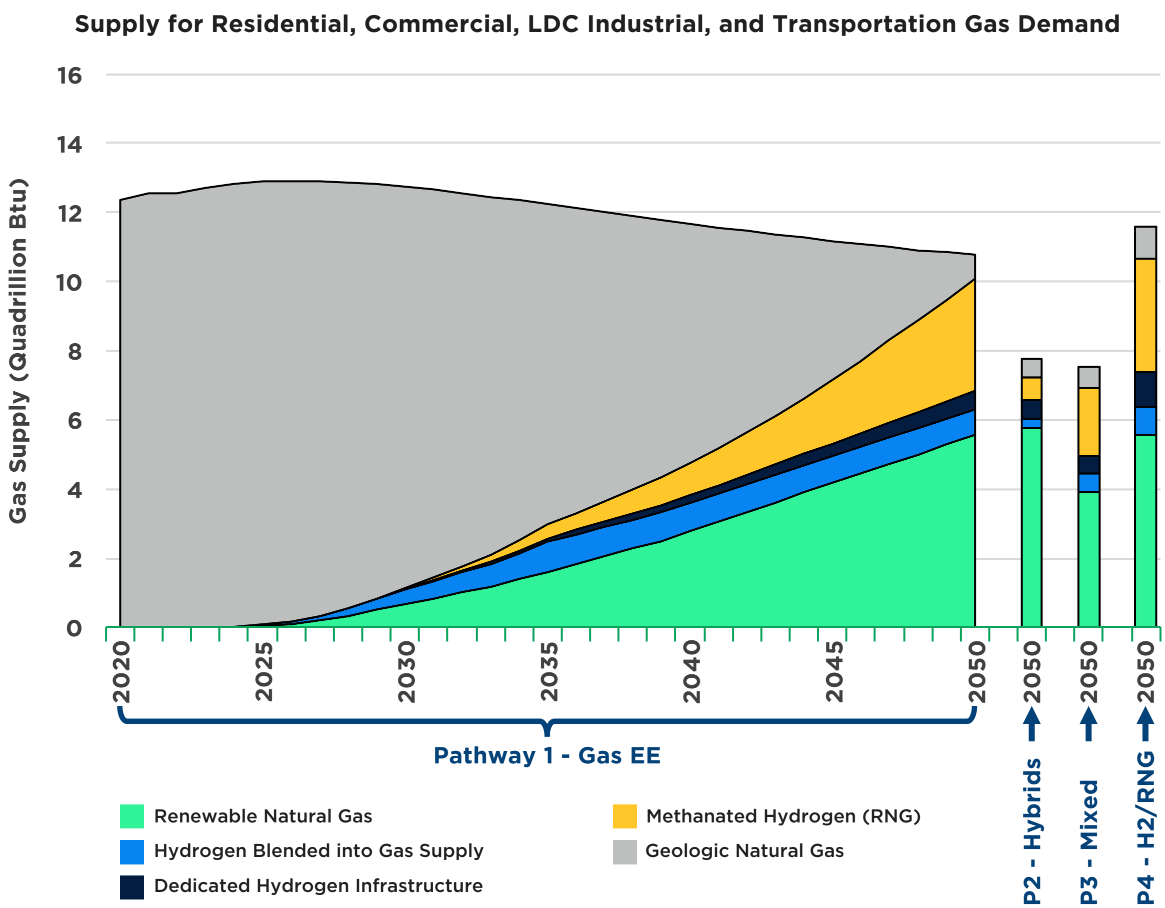
RNG has a clear role in helping different sectors to decarbonize. Uncertainties remain regarding the pace of technology advancements, competition from other sectors for this renewable energy, and policy approaches that will impact how quickly production levels can be ramped up, costs, and what total volumes might be achievable. Nonetheless, given its large potential to significantly reduce emissions, efforts should be taken to support the development and deployment of RNG and hydrogen projects as these issues are being studied and addressed. In order for the economy to reach net-zero targets, there will likely be a use for all of the renewable gas that can be produced. Although the availability of renewable gas is relatively limited at present in most regions, low-carbon fuel producers have shown the ability to ramp up production relatively quickly when a market is developed for the RNG. For example, a 2019 study performed on behalf of Argonne National Laboratory estimated that 157 RNG production facilities would be operating in the U.S. at the end of 2020 (up 78% from 2019), 76 projects under construction (up 100%), and an additional 79 projects in the planning process.[11]

11 https://energy-vision.org/wp-content/uploads/2020/12/EV-Argonne-2020-RNG-Release.pdf

Exhibit E.S. 8 shows the RNG and hydrogen gas supply assumptions included in each of the four pathways. Overall gas demand corresponds with **Exhibit E.S. 7** and is represented by the total height of the bars or bands. The graph shows the full 30-year evolution of the gas supply mix for the first pathway, and the final 2050 gas mixes for the other three pathways. Lower bars for pathways 2 and 3 represent larger reductions in gas demand. It is important to note that different combinations of the available renewable and low-carbon gas supply options could have been used in each of the pathways shown below. None of the supply mixes are 'optimized' in conjunction with the demand reductions for a given pathway. Instead, they illustrate a range of different possibilities for the gas supply. For example, Pathway 2 was used to demonstrate a possible gas supply mix if hydrogen was less abundant.

While pipeline infrastructure will still be leveraged for RNG and hydrogen in the pathways shown above, all of the pathways represent a major reduction in the consumption of geologic natural gas. However, it is important to note that this analysis and the chart above focus on utility customers and do not cover all U.S. gas demand or transportation. This chart does not include gas for power generation, transmission-connected industrial customers, or LNG exports which may continue to rely on geologic gas. The gas supply mix does not include potential hydrogen and RNG volumes used in the transportation or power generation sectors.

Exhibit E.S. 8 – Utility Customer Gas Supply Mix



To reach net-zero emissions reduction targets with some consumption of geologic natural gas remaining, a portion of the emissions associated with gas combustion would be captured using carbon capture and storage technologies in the industrial sector. We anticipate other negative emissions strategies, offsets, other emerging technologies, or more renewable and low carbon fuels to be used to close any final gaps towards net-zero emissions. These pathways are meant to illustrate potential opportunities and were not optimized, do not account for local considerations, and do not represent the full range of potential or possible gas solutions. It is difficult to predict how technology will develop over the next 30 years. A breakthrough in hydrogen production, carbon capture, or other high-impact areas could lead to the emergence of different pathway options or different mixes of measures.

There are a number of emerging strategies that can directly reduce GHG emissions or extract CO_2 from the atmosphere and sequester it. There is significant uncertainty on when different options are likely to mature and their ultimate cost-effectiveness. The advancement of such technologies could significantly alter the kinds of pathways discussed in this report and potentially allow for higher levels of geologic natural gas to continue to be used in the gas system while enabling gas utilities to achieve net-zero emissions.

With increased RD&D and coordination with the electric sector, there are greater opportunities to unlock more decarbonization measures that leverage the gas system

The net-zero pathways in this study include a balance of existing technologies in the market today, early-stage commercial technologies just beginning to reach the market, and emerging technologies at different stages of research, development, and demonstration (RD&D). RD&D funding offers a critical opportunity to support major new emissions reductions solutions, some of which may be envisioned here, while others may not yet have been conceptualized. Given the scale of the challenge in reaching net-zero greenhouse gas emissions across the economy and the inherent uncertainty in possible pathways to achieving net-zero emissions in other parts of the economy, companies and the government should continue to increase investment in gas system RD&D opportunities. Investments to unlock longer-term opportunities do not mean avoiding taking action now, particularly on the immediate actions, but parallel efforts to develop new and improved solutions can help make achieving these targets more likely and cost-effective. While RD&D needs are by no means exclusive to gas technologies, there are a number of promising areas to support, including gas heat pumps, hydrogen blending, and thermal gasification.

There may also be opportunities to take a more collaborative approach to decarbonization across both the electricity and gas systems. The current natural gas and electric systems have evolved together to meet customer energy needs with a high degree of reliability, at a relatively low cost, by effectively leveraging the relative benefits of both energy systems. Responding to the need for deep greenhouse gas emissions reductions will create fundamental challenges to both systems, particularly due to the need to shift from conventional gas supply and power generation sources to emerging renewable and low-carbon power and gas sources. Supporting a system where gas and electric utilities can continue to work together to reduce emissions could help minimize negative customer impacts, maintain high reliability, and create opportunities for emerging technologies (such as power-to-gas and hydrogen) to support the needs of both systems, accelerate carbon reductions, and improve overall energy system resiliency. All options should be on the table to ensure a cost-effective, reliable, resilient, and equitable transition to a net-zero emissions energy system, and gas and electric utilities both have roles to play to support this transition.

Supportive policy and regulatory approval will be essential for gas utilities to achieve net-zero emissions

Reaching net-zero emissions targets will require transformative changes to our energy systems and economy, and the analysis in this report lays out a series of illustrative pathways demonstrating the kinds of ways in which gas utilities can support this transition. However, gas utilities cannot implement decarbonization pathways on their own. Gas utilities operate under strict regulations by state and federal regulators and must adhere to many rules and processes. There are set parameters on the rates they charge customers to recover costs for investments and operating expenses, including the gas supply acquisitions. Natural gas utility regulations have historically focused on providing safe, reliable, and affordable service to consumers. There would be benefits to integrating environmental considerations into gas utility regulatory constructs. Environmental and climate policy must be aligned with gas utility regulatory constructs for gas utilities to continue to invest in gas infrastructure while advancing cost-effective emissions reduction opportunities.

While policy considerations and opportunities will depend on regional and state factors, some specific **regulatory actions** that could support the gas GHG emission reduction initiatives studied in this report include:

- Supporting expanded utility energy efficiency programs (e.g. through increased funding, changes to cost-effectiveness tests, etc.) to support the broader deployment of gas savings measures that are cost-effective relative to other options for reducing GHG emissions
- Developing policies that incentivize market demand for low carbon gas and advanced gas technologies in the residential, commercial, and industrial sectors
- Coordinating gas and electric system planning to understand the full range of decarbonization implications and pathway alternatives, as well as to determine the lowest cost and least-impact pathways for customers while meeting reliability requirements
- Considering updates to utility rate mechanisms and cost-recovery processes to ensure all parties are incented to support GHG emission reductions
- Developing structures to address consumer equity issues related to the distribution of decarbonization measures and impacts across all customers
- Considering methods to compensate gas customers for cost savings they achieve for electric customers through services such as energy storage, load flexibility, and peak shaving that are provided via the gas system (across a range of different measures and technologies)

Some additional **technology-focused opportunities** include:

- Supporting company-specific methane emissions factors to more accurately capture direct utility emissions and better understand the emissions reductions utilities are able to achieve
- Increasing research, development, demonstration, and deployment (RDD&D) funding for low-carbon gas and negative emissions technologies
- Promoting system modernization programs to maintain and upgrade gas infrastructure
- Improving building codes that reduce heating load while maintaining fuel choice in order to make new buildings more efficient and prioritize energy efficiency when buildings undergo major renovations
- Supporting hydrogen production and deployment through incentives, RD&D support, pilot programs, blending agreements, and codes and standards development.

Ultimately, the ability of both gas and electric utilities to successfully implement effective and tailored decarbonization strategies in their territories will be highly dependent upon support and approval from policymakers, regulators, customers, and other stakeholders. However, the extensive and complex transformations being envisioned to reach net-zero emissions targets have yet to be thoroughly examined in most regions. As a result, it's critically important that utilities, regulators, and other stakeholders perform careful and objective analyses to find the most effective, equitable, achievable, and least-cost path to net-zero—across both the electric and gas systems—that is in the best interest of customers in their service territories and jurisdictions.

The pathways in this study are illustrative of the types of approaches that could lead gas utilities to net-zero emissions by 2050. However, the optimal pathway will vary by utility and region and depends on many factors. **Exhibit E.S. 9** shows a sample of the kinds of measures and screening criteria that utilities, regulators, and policymakers could consider when developing gas emission reduction plans tailored to their region. It should be noted that thoroughly evaluating these local screening criteria requires an intensive analytical effort, and that plans will need to be re-visited periodically and evolve over time as conditions change.

Exhibit E.S. 9 – Example of Gas Utility Emissions Reduction Plan Options and Screening Criteria

Emission Reduction Options

Natural Gas Demand Reductions	Building shell upgrades (and/or code improvements focused on improving efficiency)
	High-efficiency space heating
	High-efficiency water heating
	Smart thermostats and building control upgrades
	More-efficient appliances and process equipment
	Building commissioning/ retrocommissioning
	Combined heat and power (CHP)
	District heating
	Home energy reports (behavioral efficiency)
	Low-flow hot water fixtures
	Gas heat pumps
	Electric appliances, and space and water heating equipment
	Hybrid space heating (e.g. electric heat pump paired with a gas furnace)
Renewable and Low-Carbon Gas Supply	Renewable natural gas
	Methanated hydrogen
	Hydrogen blended into gas supply
	Dedicated hydrogen infrastructure (including adoption of new end uses)
Methane Emission Reduction Measures	Differentiated gas
	Leak detection and repair programs
	More accurate emissions measurement
	Replacement of higher emitting pipe and equipment
	Operational and maintenance measures
Negative Emissions Technologies	Carbon capture and sequestration
	Direct air carbon capture
	GHG emissions offsets

Screening Criteria

Local Considerations	Local, state, and regional emission reduction targets and climate policy
	Regulatory environment (including cost-effectiveness tests, etc.)
	Climate (particularly heating degree days and extreme temperatures) and impact on measure efficacy
	Composition and age of existing building and appliance stock
	Commercial and industrial base
	Current and projected economic growth
	Current energy prices (gas and electricity)
	Composition and age of existing natural gas and electric utility infrastructure
	Existing/planned electricity generation, transmission, and distribution infrastructure (capacity, age, GHG intensity, etc.)
	Regional renewable resource potential
	Utility type (gas or dual fuel, investor-owned, municipal, co-op, etc.)
	Local/regional plans for non-gas decarbonization, and potential competitive impacts from surrounding regions
	System hydrogen conversion feasibility
Local Evaluation Criteria	Safety
	Costs and affordability
	Impacts to energy system (resiliency, peak demand impacts, reliability, etc.)
	Impacts to customers (energy prices, reliability, non-energy impacts, etc.)
	Customer equity
	Consumer preferences
	Feasibility and ability to scale
	Renewable and low-carbon supply considerations
	Implementation support required (traditional DSM program, market transformation effort, etc.)
	Technological readiness
	Expected future technology improvements (performance, costs, etc.)
	Current and projected natural gas utility rate base

Prioritized Utility Plan

Prioritized Utility Plan
Gas Utility Emissions Reduction Plan

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LIST OF ACRONYMS

Acronym	Description
ACEEE	American Council for an Energy-Efficient Economy
AD	Anaerobic Digestion
AFUE	Annual Fuel Utilization Efficiency
AGA	American Gas Association
AGF	American Gas Foundation
ASHP	Air Source Heat Pump
BAU	Business as Usual
BCF	Billion Cubic Feet
BTU	British Thermal Unit
CARB	California Air Resources Board
CCS	Carbon Capture and Sequestration
CEC	California Energy Commission
CH4	Methane
CHP	Combined Heat and Power
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
DHW	Domestic Hot Water
DOE	Department of Energy
DSM	Demand-Side Management
DSRPM	Demand Side Resource Potential Model
E3	Energy and Environmental Economics, Inc.
EIA AEO	Energy Information Administration's Annual Energy Outlook
EPA	Environmental Protection Agency
GHG	Greenhouse Gas
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies Model by Argonne National Laboratory
GSHP	Ground Source Heat Pump
H_2	Hydrogen
HER	Home Energy Report
HVAC	Heating, Ventilation, and Air Conditioning
ICF	ICF Resources LLC

Acronym	Description
IPCC	Intergovernmental Panel on Climate Change
LNG	Liquified Natural Gas
MMBTU	Million British Thermal Units
MSW	Municipal Solid Waste
NGSI	Natural Gas Sustainability Initiative
NREL	National Renewable Energy Laboratory
P2G	Power-to-gas
RGS	Renewable Gas Standards
RSG	Responsibly Sourced Gas
RNG	Renewable Natural Gas
RPS	Renewable Portfolio Standards
SMR	Steam Methane Reforming
SNG	Synthetic Natural Gas
Syngas	Synthetic Gas
TBTU	Trillion British Thermal Units
TCF	Trillion Cubic Feet
TG	Thermal Gasification
UEF	Uniform Energy Factor
WRRF	Water Resource Recovery Facility

MAIN DEFINITIONS

Annual fuel utilization efficiency (AFUE) measures average annual seasonal efficiency of a gas furnace or boiler and may be expressed as total heating output divided by total energy (fuel) input. AFUE's for furnaces can range from 55% to 97%.

Bioenergy carbon capture and storage (BECCS) is another negative emissions technology option under consideration and involves capturing the CO_2 from power plants or industrial processes that are using biogenic fuels (and hence would have been considered carbon neutral even without the CCUS).

Biogenic carbon is carbon cycling between the atmosphere and organic matter. This fast carbon cycle has a timeframe of under 500 years, in contrast with the slow carbon cycle, which moves carbon between the atmosphere and lithosphere over 100-200 million years.[12] Thus, bioenergy leverages carbon already within the fast carbon cycle, rather than drawing from the slow cycle's long-lasting geologic carbon reservoirs.[13]

Building energy codes establish minimum energy efficiency requirements for new construction and renovations and can be set to require significant reductions in energy consumption.

Building shell retrofits are improvements to the exterior, insulation, windows, and doors of buildings.

British thermal unit (Btu) is the quantity of heat necessary to raise the temperature of one pound of water one degree Fahrenheit from 58.5 to 59.5 degrees Fahrenheit under standard pressure of 30 inches of mercury at or near its point of maximum density. One Btu equals 252 calories, (gram), 778 foot-pounds, 1,055 joules or 0.293-watt hours.

Carbon dioxide (CO_2) is a gas which is a product of combustion resulting when carbon unites with sufficient oxygen to produce complete combustion, a component of many natural gases.

Carbon dioxide equivalent (CO_{2e}) is a metric that represents the atmospheric warming potential of different gases as compared to that of CO_2. In decarbonization analyses, CO_{2e} can be used to encompass the cumulative effect of multiple greenhouse gases (most often CO_2, nitrous oxide, and methane).

Coefficient of performance (COP) indicates the efficiency of refrigerant-based systems (including heat pumps), with a higher number representing a more efficient unit.

Dedicated hydrogen infrastructure is the build out of new infrastructure to enable targeted customers/clusters to convert to higher levels of hydrogen use.

Demand side management (DSM) comprises utility programs and activities designed to increase energy efficiency and influence the amount and timing of customer demand.

Direct air carbon capture is a technology option, currently under development, to capture CO_2 directly from the atmosphere.

Gas heat pumps are a technology for space and water heating in the early stages of commercialization that can achieve high heating efficiencies in the range of 130% to 140%.

12 NASA, 2011. https://earthobservatory.nasa.gov/features/CarbonCycle/page2.php

13 *The Carbon Cycle and Atmospheric Carbon Dioxide*, Chapter 3 in *TAR Climate Change 2001: The Scientific Basis*, 2001, IPCC. https://www.ipcc.ch/site/assets/uploads/2018/02/TAR-03.pdf

Gas meter is an instrument for measuring and indicating or recording the volume of gas that has passed through it.

Gas utility is a company that is primarily a distributor of natural gas to ultimate customers in a given geographic area.

Geologic natural gas refers to gas supply from shale / conventional natural gas production. It is predominantly composed of methane.

Greenhouse gases are gases that absorb infrared radiation in Earth's atmosphere, effectively trapping heat there, creating a greenhouse effect. The key greenhouse gases include water vapor, carbon dioxide, methane, and nitrous oxide.

HVAC System is a system that provides, either collectively or individually, space heating, ventilation and/or cooling within or associated with a building.

Hybrid gas-electric integrated heating systems provide space heating through the use of an electric air-source heat pump paired with a natural gas furnace and utilize integrated controls that optimize the energy consumption, emissions and cost of the system throughout the year.

Hydrogen blending into gas supply refers to hydrogen that is assumed to be mixed into existing gas infrastructure without requiring significant infrastructure upgrades.

Methanated hydrogen: a renewable natural gas (carbon neutral methane that can be blended without limit in existing infrastructure) produced by methanating clean hydrogen with biogenic CO_2.

Negative emissions technologies: strategies that can directly reduce GHG emissions or extract CO_2 from the atmosphere and sequester it.

Renewable natural gas (RNG) is methane produced by anaerobic digestion and thermal gasification from a variety of feedstocks (AGA definition).

Selective electrification is the selective use of electric appliances, equipment or vehicles that have been determined for a specific region to achieve consumer cost savings, greenhouse gas emissions reductions and reliability improvements relative to alternative energy options for the same applications.

1 INTRODUCTION & BACKGROUND

1.1 ABOUT THIS STUDY

This study was commissioned by the American Gas Association (AGA). Climate change is one of the defining challenges of our time. We cannot address climate change without fundamentally restructuring energy use throughout our economy and using every available greenhouse gas (GHG) reduction measure. To ensure that climate solutions leveraging gas infrastructure can be given proper consideration as part of broader climate planning, AGA asked ICF to provide an assessment of the opportunities for natural gas utilities to provide solutions on pathways to a net-zero greenhouse gas emissions future. This report provides an in-depth look at four potential pathways for gas utilities to reach net-zero emissions by 2050; the role of existing and emerging technologies; and other key considerations that will be essential in creating effective and equitable decarbonization initiatives.

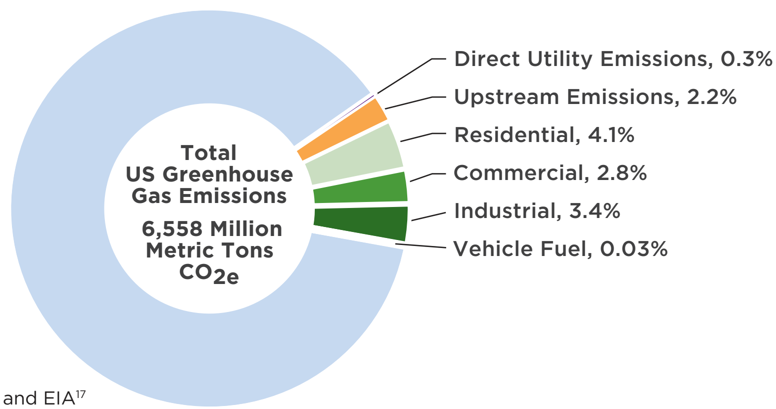
The study was a collaborative effort between AGA staff, industry representatives on the AGA working group overseeing the study, and ICF. ICF worked with AGA staff and the industry working group to develop pathways combining different technologies and approaches to net-zero emissions by 2050, with a focus on opportunities to reduce greenhouse gas emissions within gas utilities' purview - including utility operations, upstream emissions, and the direct use of natural gas by utility customers across residential, commercial, industrial, and transportation sectors. ICF also worked with AGA staff and the industry working group in developing technology and adoption assumptions consistent with current and potential technology innovation. ICF provided independent analyses of deeply decarbonized futures and led the modeling effort to assess a range of pathways to achieve net-zero emissions for gas utilities and their customers. The AGA working group contributed their expertise and worked with ICF to align on a common set of inputs and assumptions, and modeling approach. They reviewed interim and final modeling results, helped assess the study's key findings, and contributed to finalizing the report.

Broadly speaking, GHG emissions related to gas utilities can be considered in three separate categories[14]:

- **Direct gas utility emissions**
- **Customer emissions (residential, commercial, industrial, and vehicle fuel) from the onsite combustion of gas**
- **Upstream gas emissions from the production and transportation of gas purchased from utilities**

As shown in **Exhibit 1**, greenhouse gas emissions associated with gas utilities represent less than 13% of total US emissions.[15] Of those, customer emissions comprise the bulk of overall emissions linked to gas utilities. The ability of gas utilities to help their customers reduce these emissions will be critical to the country reaching economy-wide net-zero targets. Much of the analysis in this study focuses on pathways to reduce customer emissions, but separate opportunities and pathways are also presented for direct utility and upstream emissions categories.

Exhibit 1 – Total 2019 US Greenhouse Gas Emissions and GHG Emissions Categories Associated with Gas Utilities[15]



Source: EPA[16] and EIA[17]

To reach net-zero emissions targets by 2050, decarbonization policy will need to drive transformational changes in energy production, delivery, and use. These changes will need to occur in an environment with significant uncertainty in terms of technology, costs, regulatory structure, consumer behavior, and a host of other issues. This study illustrates multiple pathways to net-zero greenhouse gas emissions for natural gas utilities and their customers, highlighting a diverse range of opportunities and increasing or decreasing the emphasis on different available decarbonization strategies, but it does not attempt to offer an optimal solution for all utilities.

The approach that works best for some gas utilities may not be optimal for others. Different utilities will have very different needs, face different regional considerations, and start with very different circumstances with respect to weather, existing building stock, economic activity, and regulatory environment. Additionally, it will be critically important for individual

14 The World Resources Institute and World Business Council for Sustainable Development (WRI/WBCSD) have established widely adopted GHG measurement and tracking protocols. These protocols separate corporate emissions for reporting companies into three categories or "Scopes." This report avoids the scope terminology in an attempt to make the content easier to comprehend by a broad audience. However, the three gas utility GHG emissions categories discussed here do generally fall into the scope categories as well. Direct natural gas utility emissions are Scope 1 emissions. For gas utilities, customer emissions from the onsite combustion of gas sold by the company are Scope 3 emissions. Customer emissions from combustion of gas delivered but not sold by utilities are not included in Scope 3 but are sometimes included in this analysis. For gas utilities, upstream emissions from the production and transportation of gas they sell are also Scope 3 emissions. Scope 2 emissions related to electricity consumed by the gas utility are not included here but are typically negligible relative to the Scope 1 or 3 emissions, and would be mitigated as electricity generation shifts to net-zero.

15 The GHG emissions associated with gas utilities shown here do not include any combustion or upstream emissions for natural gas use by the electricity generation sector, or for natural gas that is not delivered by gas distribution companies (e.g., not all industrial natural gas demand is delivered by gas utilities). Total US GHG emissions are from EPA's latest ***Inventory of U.S. Greenhouse Gas Emissions and Sinks*** covering emissions in 2019. Customer emissions are calculated based on LDC delivered volumes share of national gas consumption in 2019 based on EIA-176 reporting. Direct utility emissions include methane and CO2 emissions, based on the EPA inventory and methane GWP of 25. Upstream emissions are calculated based on volumes delivered to customers captured here and an average emissions factor of 11.3 kg CO2e/Mcf.

16 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2019 – Main Text - Corrected Per Corrigenda, Updated 05/2021 (epa.gov)

17 https://www.eia.gov/dnav/ng/ng_cons_sum_a_EPG0_vgt_mmcf_a.htm

utilities to consider cost, feasibility, customer equity, energy reliability and resilience, local and national policy objectives, the existing and evolving regulatory guidelines, consumer preferences, technological readiness, and renewable and low-carbon supply considerations.

As a result, no one path that can credibly be claimed to represent the "optimal" path, or the only path, in any specific region. Similarly, although this study shows that the natural gas distribution system can play an enduring role in a net-zero future, it is not intended to provide a direct comparison with other pathway approaches, or determine which of multiple viable approaches should be preferred by policy makers and consumers.

1.2 STRUCTURE OF THE REPORT

This report documents the rationale and results of the study. **Section 2** offers a discussion of the role of natural gas in deep energy decarbonization and net-zero emissions targets. Several relevant decarbonization strategies are introduced in **Section 3**. The decarbonization pathways are presented in **Section 4**, along with the analysis results. We have identified many of the critical barriers and policy requirements that need to be addressed to implement the pathways in **Section 5** of the report. The key findings of the study are summarized in **Section 6**.

1.3 AREAS FOR FURTHER INVESTIGATION AND ANALYSIS

The study was designed to identify and assess how natural gas utilities can contribute to achieving climate change mitigation goals. This issue is extraordinarily complex and will evolve. What appears to be the best approach today may not end up as the best approach in the long term as technology, policy, and consumer behaviors change. As with any complex forward-looking projection incorporating a wide array of data inputs, the ICF analysis in this report depends on a range of assumptions that may be subject to change depending on how the energy system evolves going forward. Below are some of the key areas that may be especially likely to affect future decarbonization outcomes and strategies:

- **Availability of renewable and low-carbon gases** – This study builds on earlier analyses of renewable natural gas potentials and assumes that low-carbon fuels markets continue to evolve such that significant volumes of renewable and low-carbon gas volumes are available to meet industry requirements. An understanding of the future availability of costs of low-carbon fuels such as RNG, hydrogen, and synthetic renewable natural gas remain an area of required study and are subject to change. However, low carbon fuels technology is evolving rapidly. The volumes of renewable and low carbon fuels included in this study already reflect an increase in the resource potential compared with estimates from the 2019 ICF study conducted on this subject for the American Gas Foundation.[18] As the low-carbon fuels market evolves and matures, it will be essential that gas utilities continue to adjust their decarbonization planning accordingly.
- **Emergence of new technologies** – Within the next 30 years, there could be a number of new technological developments that could significantly alter the assumptions underpinning each of the pathways reviewed in this study. For example, these technology advances may include new battery storage technologies, hydrogen production and storage, end-use technologies, carbon-capture, or even carbon-negative technologies that are being targeted as part of the U.S. Department of Energy (DOE) Energy Earthshots[19] and other initiatives.

18 *Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment,* American Gas Foundation, 2019: https://gasfoundation.org/2019/12/18/renewable-sources-of-natural-gas/

19 https://www.energy.gov/policy/energy-earthshots-initiative

- **Efficacy of electric decarbonization initiatives** – Many analyses of decarbonization pathways, including this one, assume that electric utilities will be able to reach net-zero greenhouse gas emissions by 2050. However, this level of comprehensive decarbonization will be challenging to achieve. If the power sector falls behind schedule, there may be additional opportunities for gas utilities to contribute to net-zero initiatives across the entire energy sector.

- **Transportation decarbonization** – This study did not evaluate the impact of decarbonizing the transportation sector. However, beyond the increasing adoption of electric vehicles, it's also possible that vehicles (particularly medium- and heavy-duty transportation) could increasingly rely on technologies such as hydrogen fuel cells to meet net-zero goals. Such a development could have significant impacts on gas utilities' decarbonization plans and overall business models.

- **Changing energy needs and system reliability** – Given the likelihood of emergent challenges stemming from climate change to various energy systems and technologies, it will be essential to maintain an ongoing awareness of (and focus on) reliability and resiliency and to update decarbonization plans accordingly. Similarly, any decarbonization plans assuming some level of fuel switching or electrification should also maintain an ongoing focus on both these issues to ensure future success.

- **Emerging opportunities for collaboration** – There may be a range of emerging opportunities to take a more collaborative approach to decarbonization across the electricity and gas systems. A decarbonization plan where gas and electric utilities can continue to work together to reduce emissions could better support lower energy costs and improved reliability and create opportunities for emerging technologies (such as power-to-gas or hybrid heating systems) to support the needs of both systems, accelerate carbon reductions, and improve overall energy system resiliency.

2 THE IMPORTANCE OF NATURAL GAS INFRASTRUCTURE IN DECARBONIZATION PATHWAYS

The Intergovernmental Panel on Climate Change has indicated that deep reductions in greenhouse gas emissions will be necessary to mitigate the largest risks of climate change, and that net-zero emissions will likely be needed by 2050 in order to limit global warming to 1.5°C (in line with the Paris Agreement).[20] As a result, policymakers at the local, state, and national level—and corporate leaders—have set deep emissions reductions targets to be achieved by 2030 or 2035 and more aggressive targets to be achieved by 2050. In some states and localities, these targets have been codified into law. In other jurisdictions, these reflect policy guidelines and objectives. However, despite the urgency of these targets, plans for implementation of the necessary strategies to adhere to them are often either lagging or do not exist at all.

Identifying and implementing the appropriate strategies that can help the U.S. reduce its greenhouse gas emissions to net-zero by 2050 is a complex technical and economic task. Successful decarbonization of the energy system will impact consumers in multiple ways and necessitate changes in behavior. The burden on consumers and communities to make this transition must be minimized if it is to succeed. Consumers will likely need to be convinced that the benefits of decarbonization efforts exceed the transition costs.

Many of the discussions and analyses that have been completed to date have focused on the need to decarbonize electricity production and then rely on the decarbonized electricity to displace the use of fossil fuels in a range of energy end uses. Electrification of some fossil fuel demand is expected to be part of almost all strategies to achieve net-zero targets. However, electrification paired with low-carbon electricity may not necessarily be the best decarbonization pathway, and a sole decarbonization pathway raises practical implementation challenges. As key stakeholders analyze their options, it will be essential to address the impacts of the uncertainty related to the cost, feasibility, equity and reliability of building electrification.

While reductions in energy demand and electrification of existing end-uses served by fossil fuel applications will be among the pathways to decarbonization, the use of the existing gas infrastructure (including the gas distribution system to transport renewable and low carbon gaseous fuels to replace or be blended with fossil fuels) can also enable viable decarbonization options. Pathways that instead leverage decarbonization strategies using the gas system may have the potential to better maintain low energy costs, improve system reliability, create opportunities for emerging technologies (such as power-to-gas and hydrogen) to support the needs of both the gas and electric systems, accelerate carbon reductions, and improve overall energy system resiliency. In particular, some potential benefits include:

- Utilizing the capacity and reliability associated with the existing gas distribution system to bolster decarbonization strategies across gas and electric systems
- Minimizing challenges and uncertainties associated with full electrification of fossil fuel demand
- Maintaining the flexibility to adapt long term climate change policy as new technologies are developed and as challenges become apparent with other options

20 *Summary for Policymakers of IPCC Special Report on Global Warming of 1.5°C approved by governments,* 2018, IPCC. https://www.ipcc.ch/2018/10/08/summary-for-policymakers-of-ipcc-special-report-on-global-warming-of-1-5c-approved-by-governments/

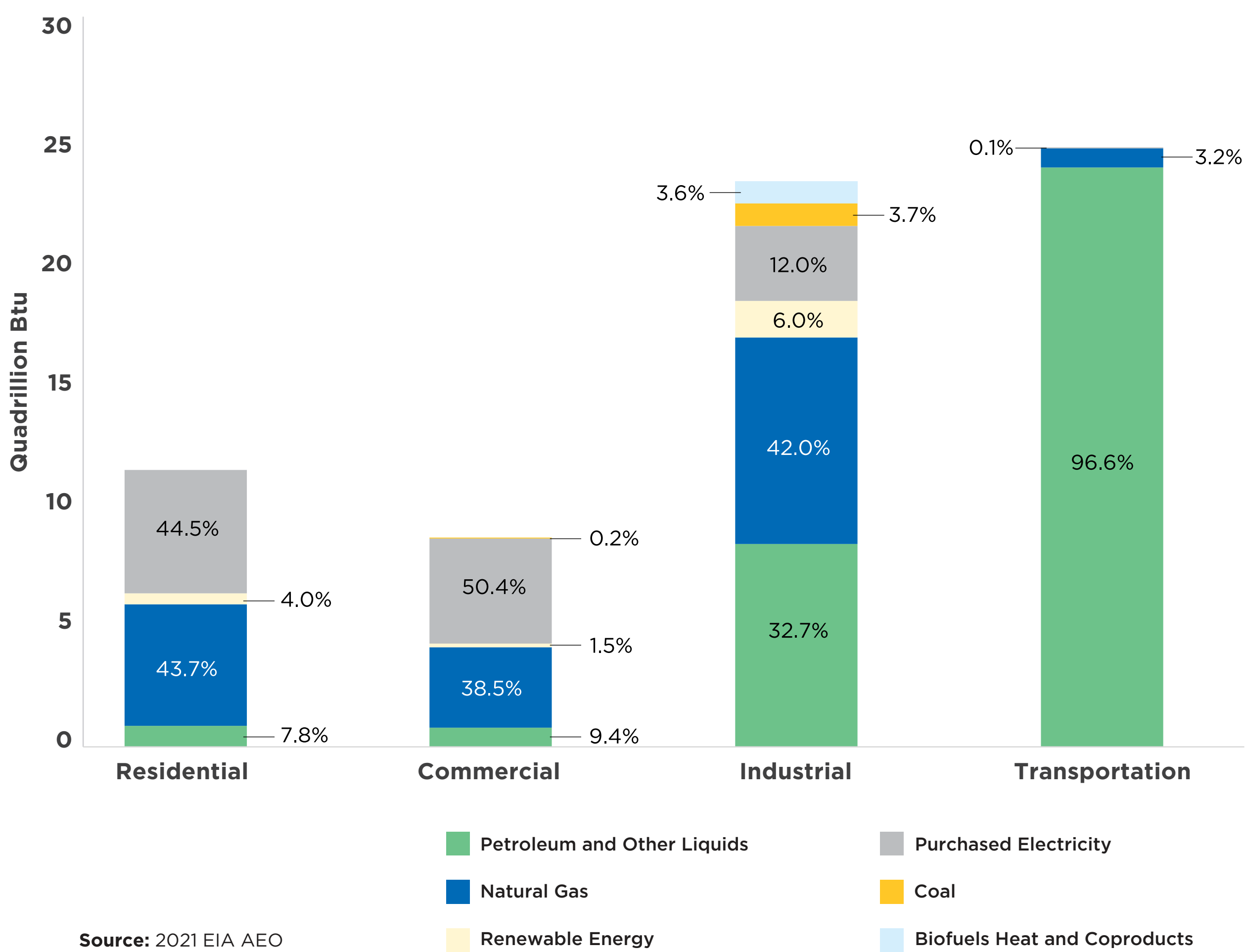
- Minimizing disruptions to energy consumers
- Potential reductions in the cost of meeting decarbonization targets
- Adding optionality to enable a greater range of greenhouse gas reduction strategies to increase the likelihood of meeting climate change mitigation goals within the necessary timeframe

These potential benefits underscore the need to consider a full range of decarbonization approaches across multiple fuel sources and are explained in greater detail below.

2.1 VALUE OF THE EXISTING NATURAL GAS DISTRIBUTION SYSTEM IN THE U.S. ECONOMY

Natural gas is a core component of the U.S. energy system. Approximately 30.5 trillion cubic feet (Tcf) of natural gas was used in the United States (U.S.) in 2020, accounting for 34% of U.S. total energy consumption and 28% of end-use energy requirements. As shown in **Exhibit 2**, the total end-use consumption of natural gas was about 16.1 quadrillion Btu, which was equally split between the buildings sector (residential and commercial) and the industrial sector.

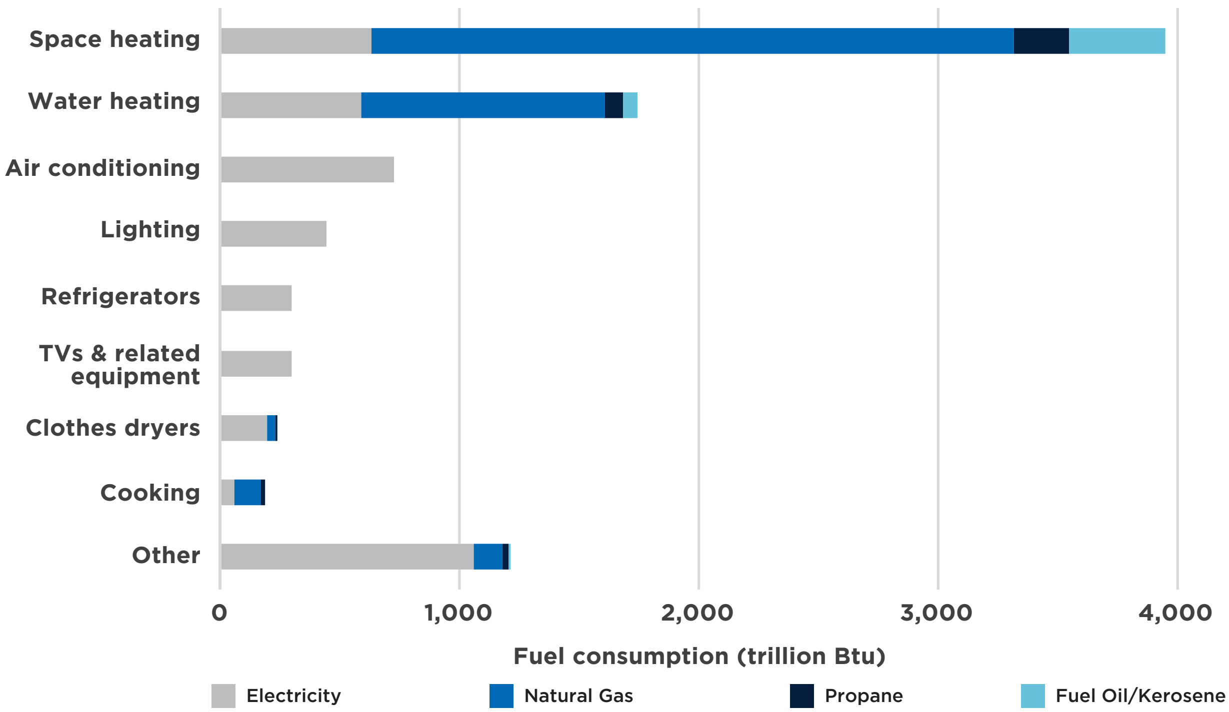
Exhibit 2 – U.S. Energy Consumption by Source and Sector in 2020



Source: 2021 EIA AEO

More than fifty percent of American households currently use natural gas as a heating fuel, and reliance on gas is even higher in many colder regions of the country. Natural gas dominates space and water heating consumption in residential households, as shown in **Exhibit 3**, and is also widely used in commercial and industrial facilities.

Exhibit 3 – U.S. Household End-use Energy Consumption by Fuel (trillion Btu)



Source: EIA 2015 Residential Energy Consumption Survey

The scale of the U.S. economy's dependence on gas infrastructure means that any realistic pathway to net-zero emissions by 2050 will need to address carbon and methane emissions associated with the use of natural gas. However, the current reliance on gas infrastructure also highlights the importance of utilizing the existing infrastructure to address climate change. Customers and policymakers alike have long favored gas for its affordability, reliability, resiliency, and its ability to store and deliver massive amounts of energy when cold outdoor temperatures drive large spikes in space heating energy use, and those benefits also offer important opportunities when considering pathways to a net-zero emissions future.

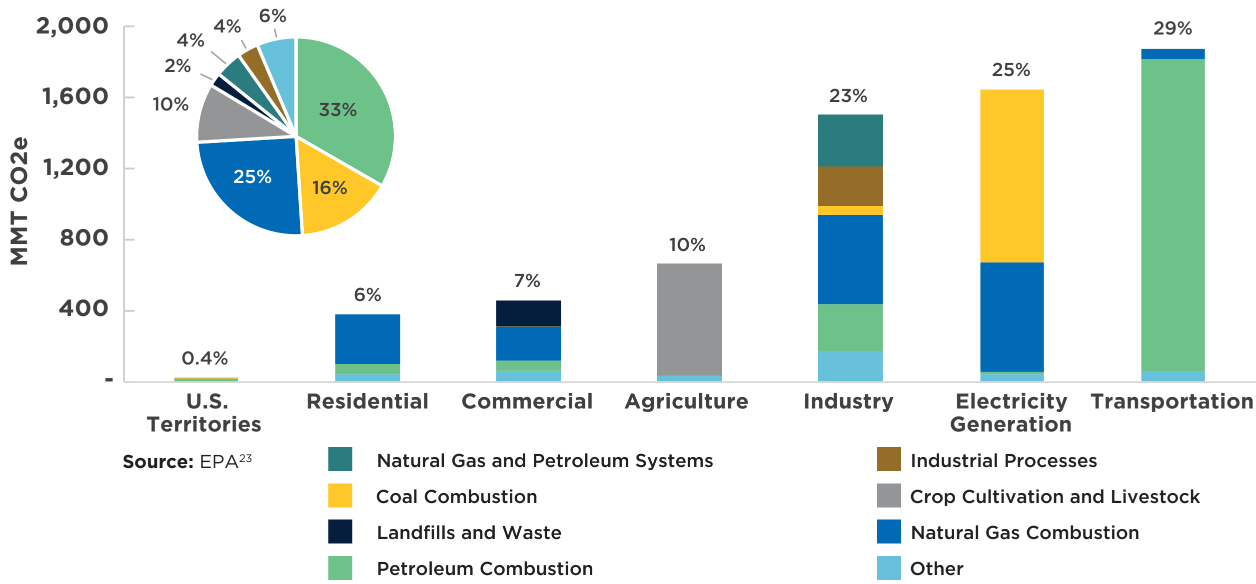
As shown in **Exhibit 4**, residential and commercial buildings currently account for about 13% of direct economy-level greenhouse gas emissions, mainly due to the use of natural gas and petroleum products for heating and cooking needs. In comparison, the industrial sector accounts for 23%.[21] Emissions from natural gas consumption represented 80% of the direct fossil fuel CO_2 emissions from the residential and commercial sectors in 2019. Emissions associated with electricity generation and use collectively represent about 25% of economy-level emissions.

It's important to note that the peak space heating load currently served by natural gas is significantly larger than what the electrical system is designed for in most regions. This is largely because the existing gas energy storage and delivery infrastructure was primarily designed to reliably serve customers through spikes in consumption during cold winter periods, while the electric infrastructure was generally designed for lower levels of peak demand (largely driven by summer air conditioning loads). Over the last five years, the demand for natural gas during the coldest winter month has been about 58% higher than

21 https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions

the demand for electricity during the peak summer month within the buildings sector, and about 84% higher than the demand for electricity for all end-uses. **Exhibit 5** compares total monthly electricity and gas demand in the U.S.

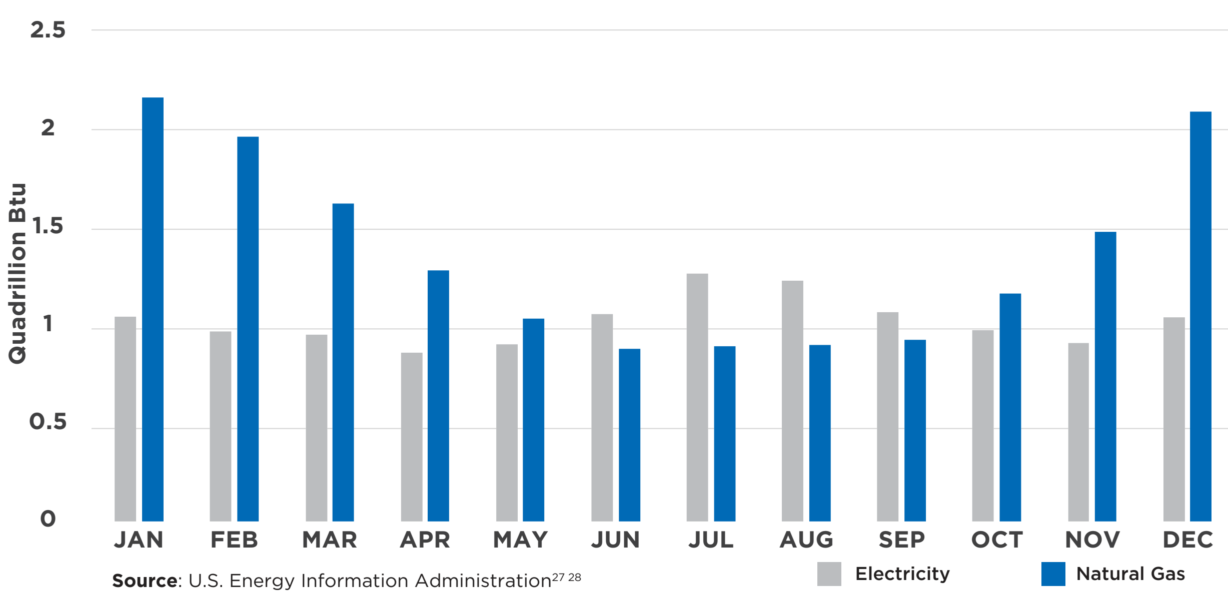
Exhibit 4 – Total U.S. Direct Greenhouse Gas Emissions[22] by Economic Sector in 2019



Source: EPA[23]

The relationship is similar when compared on a peak daily basis. Over the last five years, peak daily gas demand during the winter has exceeded the peak daily electricity demand by about 62% during the summer.[24 25 26]

Exhibit 5 – 2020 US Electric and Natural Gas Consumption Across all Customer Sectors



Source: U.S. Energy Information Administration[27 28]

22 The category "natural gas combustion" includes all emissions from gas combustion. The emissions associated with gas utilities presented earlier in Exhibit 1 are a subset of these emissions, and did not include electricity generation emissions or combustion of gas that was not delivered by gas utilities.

23 Greenhouse Gas Inventory Data Explorer | US EPA

24 Based on data from Ventyx for the Lower-48 U.S. for January 20, 2019 natural gas load relative to the July 25, 2016 electric load.

25 Based on Ventyx data, peak winter electricity load on January 2, 2018 exceeded the peak summer electricity load. Peak natural gas load exceeded peak winter electricity load by 57 percent.

26 The peak day comparisons do not account for differences in peak hour. Peak hour gas demand is generally not available, however industry rules of thumb for hourly gas demand (peak hour = 5% of peak day) are broadly consistent with the relationship between peak hour and peak day for electric demand. For the U.S. lower-48, peak hour electric demand was 4.83% of peak day demand.

27 EIA Electric Power Monthly (Retail sales of electricity to ultimate customers - Monthly by Sector) - https://www.eia.gov/electricity/data.php#sales

28 Based on data from Ventyx for the Lower-48 U.S. for January 20, 2019 natural gas load relative to the July 25, 2016 electric load.

2.2 CHALLENGES AND UNKNOWNS WITH COMPREHENSIVE BUILDING SECTOR ELECTRIFICATION AS A DECARBONIZATION STRATEGY

A number of jurisdictions have set aggressive goals to reduce emissions from building energy use through policy-driven electrification of both new and existing building stocks. The movement toward electrification as a decarbonization approach for the buildings sector is driven in part by a combination of advancements in renewable energy generation and improvements in building and appliance technologies. However, electrification paired with low-carbon electricity is only one of many potential decarbonization pathways, and it is not without limitations and challenges. It is critical that decision-makers carefully address uncertainty about the cost, feasibility, equity, and energy reliability impacts of mandating building electrification or incentivizing electrification over other decarbonization options.

A few of the major uncertainties associated with rapid electrification of the fossil fuel demand as a universal solution in the buildings sector are summarized below. Some of these potential impacts are explored in more detail in the AGA's 2018 study on the Implications of Policy-Driven Residential Electrification.[29]

Technology innovations such as highly-efficient air-source heat pumps (ASHP) for space and water heating reduce the potential impacts of building electrification on the electric grid. However, the efficiency and economics of those technologies depend on factors such as local climate and the mix of buildings by age and type. For example, the unit cost and efficiency of 'cold climate' air-source heat pumps are improving. However, most units still rely on backup electric resistance heating for very cold periods – which means they still can lead to significant new peak loads on electric infrastructure. As demonstrated by the 2021 cold snap in Texas, energy infrastructure needs to be built to accommodate such peaks – even if very cold periods are infrequent.

While careful analysis is required to understand the full extent of any challenges in a specific region, electrifying buildings can spur additional infrastructure costs if it's necessary to increase available generating capacity and upgrade the electricity grid to meet a new peak in electricity demand. Adding significant levels of electric space heating often shifts the electric grid from summer peaking to winter peaking. Many local power distribution grids would require significant upgrades to handle the additional load from comprehensive building electrification.

In addition to implications on the electric system infrastructure, electrification of residential and commercial buildings can have potentially costly ramifications or technical limitations that will impact current gas customers. For example, retrofitting commercial buildings in major urban centers can be extremely difficult. In the 2021 Pathways to Carbon-Neutral NYC report, the authors found that many smaller commercial buildings were built before 1945 with steam heating systems and limited space in mechanical rooms.[30] In the U.S. there are nearly 6 million commercial buildings and 46% of those buildings were built before 1979. In the residential sector, homeowners experience diverse barriers to making home energy upgrades (including converting to electric equipment), from the financial costs (for instance, in existing buildings ASHP installation complexity and costs vary significantly by building type/age), to behavioral barriers (for example, consumers with preference for gas cooking), and practical constraints (like the need to restore heat as quickly as possible when a furnace fails in winter). In multifamily residences, the landlord-tenant split-incentive and the need for units to be vacated (to accommodate some major electrification retrofits) can be a major challenge. Again, it is critical to study all these costs, impacts, and customer preferences for a specific region and customer type.

29 AGA_study_on_residential_electrification.pdf

30 *Pathways to Carbon-Neutral NYC: Modernize, Reimagine, Reach*, NYC Mayor's Office of Sustainability, Con Edison, and National Grid, 2021: https://www1.nyc.gov/assets/sustainability/downloads/pdf/publications/Carbon-Neutral-NYC.pdf

Some additional factors that will affect the impact of building electrification include:

- The region's existing generation capacity and outlook for new generating capacity coming online. New renewable energy resources combined with energy storage baseload capacity offer a viable path to serve increased demand from electrification while reducing carbon emissions. While renewable electricity resources like solar and wind have become relatively inexpensive compared to conventional fossil resources, storing power from those intermittent resources remains expensive. While declining battery storage prices support shifting renewable power to different hours of the day, replacing dispatchable fossil fuel generation and storage capacity is particularly challenging for long-duration seasonal or reliability requirements (for example, having multiple days of stored electricity to cover periods of low renewable generation).
- The region's adoption rate of EVs, how much that will shift energy demand from gasoline to electricity, and whether there are policies and incentives in place to shift EV charging out of peak demand periods. Both vehicle and building electrification can tax the distribution grid, so measures should be taken to avoid these increases in electric load occurring at the same time and in the same places.
- The efficiency of the building stock in a region. The cost of all forms of energy is expected to go up in pursuit of carbon-neutral targets. Energy efficiency is often the least expensive strategy and, therefore, should be the first action taken in many cases., Before pursuing building electrification, it may make sense to prioritize and incentivize energy efficiency upgrades, such as building envelope upgrades.
- Natural gas distribution systems are designed to provide service reliably with a plan to serve firm customers without disruption during peak winter periods, often called a "design day." Winter load fluctuations (the difference between peak design day and an average winter day) tend to be much higher than fluctuations in summer loads, creating additional challenges associated with reliability. It is critical to understand the expected performance of end-use equipment on peak cold days when ASHPs may rely on electric resistance back-up and to understand electric system requirements to meet design day peak demand for electrified end-uses.
- Replacing the energy system reliability and resiliency currently provided by the natural gas transmission and distribution system with an electric grid designed for a net-zero emission outcome will be an extremely challenging and uncertain process. According to EIA data on total electricity demand by region, the electric grid is already close to its capacity for winter peaking. On January 2, 2018, electricity demand in the Lower-48 states reached 98.5% of the highest summer day in the prior five years (on August 11, 2016). Peak winter electric load has already exceeded peak summer load on a daily basis in many regions of the country, including the Southeast, Midwest, and Mid-Atlantic regions.[31]
- Most decarbonization studies have not addressed the cost of decommissioning the gas system if all customers were to electrify fully.

Resiliency
refers to events that are not likely but have large impacts. Resiliency is already a matter of concern in many parts of the country, including the ability to effectively operate during major winter storms.

Reliability
reflects the ability to maintain service during generally foreseeable circumstances.

31 Energy Information Administration, Total Electricity Demand by Region (MWH). https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48?src=email

The challenges and opportunities for electrification will also depend on the scale, speed, and sectors being electrified. Not all forms of electrification will have the same costs or impacts, and some gas uses like space heating will pose a particular challenge to electrify given their peaky nature. The challenges discussed above highlight how full electrification of any sector of the economy would be extremely expensive and is unlikely to be feasible. As a result, decarbonization of the economy will not mean full electrification, nor is full electrification likely to be the most effective pathway to net-zero emissions in every region by 2030 or even 2050.

2.3 REACHING NET-ZERO IS LIKELY MORE ACHIEVABLE WITH MULTIPLE APPROACHES

The goal to decarbonize much of the U.S. economy and to achieve net-zero GHG emissions in specific jurisdictions by 2050 is an ambitious goal by any measure.

The analysis presented in this report suggests that there is a range of pathways to net-zero greenhouse gas emissions utilizing the gas system and that taking an integrated approach to decarbonization leveraging the unique advantages of the gas distribution system is likely to support a more effective, reliable, resilient, and equitable transition to a net-zero energy system.

In the near term, most of the decarbonization efforts will rely on technologies that are currently commercially available or in the final stages of commercialization. However, in the mid-to-long term time frame, technologies that are currently only in the pilot phase or conceptual phase may play a major role in successful decarbonization efforts. Technologies that have not yet been commercialized are likely to influence the long-term approach to decarbonization. The International Energy Agency (IEA) stated in their Net Zero by 2050 report that by the year 2050, almost 50% of the reductions in CO_2 emissions must come from technologies that are "currently at the demonstration or prototype phase. Major innovation efforts must take place this decade to bring these new technologies to market in time."[32] However, we don't know when—or if—these innovations will arrive. We don't know when consumers will be ready to adopt them. That is the uncertain landscape stakeholders, including utilities, policymakers, regulators, businesses, and consumers, face today when many decisions need to be made in the short term that will guide decarbonization efforts for years to come. Local considerations especially will create many different pathways to decarbonize.

One of the fundamental advantages of decarbonizing the gas system is the ability to leverage existing gas transmission and distribution infrastructure in support of emissions reductions objectives. The current gas system represents an existing long-term investment in energy infrastructure that connects to more than half the households in the U.S., complements the capabilities of the power grid. The continued ability to use gas assets to deliver energy is likely to reduce the overall investment in new infrastructure associated with decarbonization, reduce risk, and could substantially reduce the transition's costs and complexities by minimizing disruptions to customers.

The best approach to reaching a broad decarbonization goal is not yet known. The changes that will be needed to the energy distribution systems and how consumers will adapt to using energy to reach this goal are not yet known. This study's analysis of approaches to decarbonizing the natural gas distribution system indicates multiple potential pathways to reduce greenhouse gas emissions associated with gas demand in the buildings and industrial sectors. However, there is also uncertainty inherent in all of the options available to address climate change.

32 https://www.iea.org/reports/net-zero-by-2050

There is significant value in considering multiple alternative approaches to maintain the flexibility to respond to changes in technology or the market. Adopting multiple approaches to decarbonization, maintaining the flexibility to adapt the decarbonization plans when there are changes in circumstances, and relying upon gas system decarbonization and other approaches to reach climate objectives will maximize the overall value of flexibility while reducing overall risk.

3 INTRODUCTION TO KEY NATURAL GAS EMISSION REDUCTION STRATEGIES

There is a wide range of options to leverage gas infrastructure and technologies to support reductions in GHG emissions. Some are well-established technologies, which should see more urgent support to drive broader adoption. Others include emerging technologies that will need support to reach scale in markets. Still other opportunities need RD&D funding to develop. It is important to consider all possible options when planning pathways to net-zero in order to develop more viable solutions and increase the likelihood of reaching ambitious climate targets. That includes the options outlined in this report while leaving the door open for other technologies and strategies that we have not yet conceived.

The emission reduction strategies for gas utilities included here can be categorized into four approaches, as highlighted in **Exhibit 6**. The first approach is to reduce gas demand; the second is to decarbonize the remaining gas required to satisfy demand; the third is to reduce fugitive utility and upstream emissions from methane leaks; and the fourth is to use negative emissions technologies to offset remaining GHG emissions. It is important to note that while this section focuses primarily on gas-centric technologies, a wide range of other technologies would also be required to reach net-zero targets. **Section 4.1.3** discusses the scope of this analysis in more detail—but this study generally assumes a transition to net-zero happens across the economy, including in sectors not analyzed in this study.

Exhibit 6 – Examples of Gas Utility Approaches to Reducing Emissions

3.1 STRATEGIES TO REDUCE NATURAL GAS UTILITY CUSTOMER DEMAND

There are two fundamental approaches to reducing site-level gas utility customer consumption with the goal of decreasing associated emissions: improving the gas efficiency (by directly improving gas end uses or upgrading elements like building shells to reduce gas waste) or replacing natural gas-consuming equipment with alternatives that use a different source of energy (such as renewably-produced electricity or hydrogen) that result in lower emissions even if overall energy consumption remains the same or increases. In both cases, a range of established and emerging technologies will likely be needed to meet net-zero goals, though the exact mix of measures will vary by utility and region. This section of the report provides an overview of multiple such measures, and discusses where fuel-switching may or may not be effective. Although not intended to be exhaustive, this list describes some of the most common measures that many gas utilities are already able to support, as well as additional opportunities that offer the potential for significant emissions reductions.

3.1.1 EXISTING GAS ENERGY EFFICIENCY OPTIONS

Energy utilities across the U.S. have seen ongoing success with demand-side management (DSM) programs aimed at improving the efficiency of electric and natural gas end uses. According to a 2020 AGA report, natural gas utilities helped customers save 259 trillion Btu of energy and offset 13.7 million metric tons of carbon dioxide emissions from 2012 through 2018 in the US.[33] In a separate 2020 report from Lawrence Berkeley National Laboratory, researchers examined the results from 37 different utilities/program administrators across 12 states over six years and found an average overall levelized program cost of saved natural gas across all of those portfolios of $0.40/therm.[34] Commercial and industrial efficiency programs were especially cost-effective, yielding an average cost of just $0.18/therm. That level of cost-effectiveness is difficult to match through non-efficiency approaches to gas demand reduction, and it underscores the importance of energy efficiency in any successful decarbonization plan.

In some regions, low gas prices have made it challenging to pursue expanded efficiency measures based on traditional DSM program rules and cost-effectiveness tests. However, there are many new opportunities for natural gas efficiency. Researchers noted in a 2020 American Council for an Energy-Efficient Economy (ACEEE) paper titled Sustaining Utility Natural Gas Efficiency Programs in a Time of Low Gas Prices, "based on our review and analysis, we conclude that natural gas energy efficiency programs are sustainable and worth pursuing for both economic and environmental reasons."[35]

In the context of emerging industry-wide net-zero emissions goals and other mandates, there may also be additional opportunities to pursue more aggressive gas efficiency initiatives. For instance, regulators could consider the benefits to customers and adjust cost-effectiveness tests to better encapsulate the value of GHG emission reductions in order to help support expanded gas efficiency efforts. Alternatively, other complementary strategies like the decarbonization of gas supply could make efficiency even more attractive and cost-effective to pursue. Low-carbon or net-zero goals may also support expanded efficiency offerings for income-qualified customers. According to the US Energy Information Administration, the average price per BTU of delivered electricity in 2020 was 3.6 times higher than natural gas in the residential sector,[36] suggesting that natural

33 *Natural Gas Efficiency Programs Report 2018 Program Year*, American Gas Association, 2020: https://www.aga.org/globalassets/aga-ngefficiency-report-py2018-5-2021.pdf

34 *Cost of Saving Natural Gas through Efficiency Programs Funded by Utility Customers: 2012–2017*, Lawrence Berkeley National Laboratory, 2020: https://escholarship.org/uc/item/0164134n

35 https://www.aceee.org/sites/default/files/pdfs/sustaining_utility_natural_gas_efficiency_programs.pdf

36 Based on EIA reported US average annual 2020 delivered prices of 13.2 cents/kWh ($38.69/MMBTU) for electricity and $10.84/MMBTU for natural gas for residential customers

gas efficiency has the potential to drive deeper bill savings for many existing natural gas customers compared with other decarbonization strategies such as electrification. And gas utilities are already well-positioned to support such efforts: according to data from the AGA, natural gas utilities spent $365.34 million on low-income efficiency programs and assisted more than 214,581 low-income participants in 2018 alone.[37]

Some of the opportunities possible to consider funding, often through existing utility program structures, including the following:

Existing Building Retrofits

Building retrofits offer substantial potential to reduce energy consumption and associated emissions and to improve comfort for occupants.

One of the first areas to target is typically the building shell, which comprises the building's exterior, insulation, windows, and doors and has an outsized impact on heating, ventilation, and air conditioning (HVAC) requirements. As a result, it is typically the single largest contributor to energy use in residential and commercial buildings, and improvements can have a significant impact on overall energy consumption. This is particularly true for older buildings with lower insulation levels, single-pane windows, or poor air sealing. There are a number of both established and emerging measures to improve the building shell, which broadly fall into a few general categories: insulation improvements (for walls, roofs, attics, and basements), air sealing (reducing air leaks), and high-performance windows or doors.

So-called "deep energy retrofits" aim to simultaneously improve the efficiency of the building shell and the most energy-intensive end uses inside it to yield substantial savings as cost-effectively as possible. By taking a whole-building approach (rather than just focusing on improving individual end uses in a more piecemeal manner), deep energy retrofits have the potential to yield energy savings of more than 50% and even improve the building value. In addition to building shell measures, these retrofits may include gas-saving strategies such as:

- Duct sealing, which ensures that conditioned air goes where it is needed, rather than being wasted (with associated energy penalties)
- Energy or heat-recovery ventilation (ERV or HRV), which transfers heat (and in the case of ERV, moisture) between incoming and outgoing air streams to reduce HVAC loads
- Controls to improve space and water-heating efficiency
- Adding heat recovery systems to reduce waste heat and associated energy consumption
- New and more efficient HVAC equipment
- New water heating equipment
- Building commissioning to ensure that key systems are working efficiently and as intended

37 *Natural Gas Efficiency Programs Report 2018 Program Year*, American Gas Association, 2020: https://www.aga.org/globalassets/aga-ngefficiency-report-py2018-5-2021.pdf

By expanding their residential and commercial DSM programs to take a more holistic approach, gas utilities are a natural partner to help building owners overcome a range of adoption barriers that could otherwise limit savings potential (such as cost, education, and implementation effort) and realize substantial savings that can directly contribute to decarbonization goals and other benefits.

Low Energy Building Codes & New Construction Programs

A key opportunity for gas demand reductions comes from building codes that establish minimum energy efficiency requirements for new construction and building renovations. Improving efficiency in new buildings through effective design and equipment specification is often much easier and less expensive than retrofitting existing buildings, making it a particularly cost-effective way to reduce energy consumption. Since a significant level of new construction is expected by 2050, upgraded codes that prioritize higher levels of efficiency will prove important in any emissions reduction pathway. Additionally, stronger building codes and utility new construction programs are well-suited to support customer choice since they can support decarbonization pathways using both electric and gas end uses.

Building energy codes can be divided into two primary frameworks, prescriptive codes and performance codes.

- **Prescriptive** codes assign specific minimum criteria that must be met when constructing a building (e.g., minimum insulation levels [R-values] and installation and control requirements for HVAC systems).
- **Performance** codes set a minimum energy performance target, giving building architects and engineers more flexibility in how they meet the targets. For example, a building in a cold climate may achieve more energy benefits (across both gas and electric consumption) by emphasizing high-performance insulation and HVAC systems over lighting design. In a marine climate, however, a focus on maximizing natural daylight through windows may provide more benefits than upgrading insulation.[38]

One jurisdiction with a leading energy building code is British Columbia, Canada. As shown in **Exhibit 7**,[39] the BC Energy Step Code phases in a plan to shift the construction industry to 'net-zero energy-ready' buildings over three building code cycles, with progressively greater levels of energy efficiency requirements over the 2018 base building code in 2022 (20% more energy efficient), 2027 (40% more energy efficient) and 2032 (80% more energy efficient). This performance code focuses on achieving 80% energy reductions, not limiting customer choice or regulating the types of energy customers can use for the significantly lower building energy requirements. It is an efficiency and GHG-focused code that is fuel-neutral, concerned with the end results without prescribing a singular approach. The main gas utility in that province, FortisBC, has demonstrated how natural gas can still be used to heat qualifying 'net-zero energy-ready' homes, is providing incentives and guidance to help builders in the transition, and also offers customers the choice of renewable natural gas to achieve further GHG emission reductions.

38 https://www.aceee.org/sites/default/files/zeb-codes.pdf
39 https://energystepcode.ca/how-it-works/

Exhibit 7 – BC Energy Step Code Approach to New Construction

Source: https://energystepcode.ca/how-it-works/

High-Efficiency Gas Furnaces

HVAC is typically the single largest source of energy consumption in buildings, so improving the efficiency of gas heating is an especially effective and practical approach to reducing emissions. According to the Energy Information Administration (EIA), roughly 40% of homes in the U.S. use natural gas furnaces for space heating, with the Midwest region having by far the highest proportion of gas furnaces (63%).[40] The efficiency of residential furnaces is measured using a metric called Annual Fuel Utilization Efficiency (AFUE)—the higher the AFUE rating, the more efficient the furnace is. Baseline equipment (meeting current federal efficiency standards) has an AFUE of 78%, and the EIA's AEO suggests the average efficiency of gas space heating equipment in U.S. homes is 80%. But much more efficient furnaces with AFUEs of 95% or even 98% are commonly available and can offer gas heating savings as high as 20%.

High-Efficiency Gas Water Heaters

In residential and commercial buildings, water heating is typically the largest energy-consuming end-use behind HVAC. According to the U.S. Energy Information Administration, roughly 50% of residential customers and 40% of commercial customers across the U.S. use natural gas water heating, with more northerly states tending to have higher proportions of gas water heating. Electric water heaters are more prevalent in southern states, where electricity prices tend to be lower and groundwater temperatures are higher.

There are two primary opportunities for improving the efficiency of gas water heaters: upgrading to condensing models (which extract more heat from the flue gas before it leaves the water heater) and tankless water heaters, which heat water as needed without the use of a storage tank and can offer unlimited hot water to users. In residential applications, ENERGY STAR-qualified condensing water heaters can reduce water heating gas demand by around 15%, while qualified tankless models can result in savings of more than 30%. Condensing tankless water heaters combine both approaches

40 2015 Residential Energy Consumption Survey Data: https://www.eia.gov/consumption/residential/data/2015/

and are the most efficient models currently available, with efficiencies (measured using a metric called Uniform Energy Factor, or UEF) as high as 97% and savings of more than 40% compared with standard models.

Behavioral Programs and Gas Use Reductions

Home energy reports (HERs) and other behavioral programs have become more popular over time with utilities since they offer demonstrated energy savings (typically up to 2% for both gas and electricity) across a broad segment of utilities' customer bases at very low cost compared to other efficiency measures. HERs often use social norms (e.g. how do you compare with your neighbors, and what next steps should you take to reduce your energy use?) and other behavior-change strategies to help educate customers about how they consume energy and help them become more efficient. Gas HERs, for example, might help customers understand that taking simple steps (shorter showers, allowing slightly colder temperatures in winter, conducting an energy audit, etc.) can help reduce their bills. Although many HERs to date have been primarily targeted at electric customers, gas HERs can help utilities realize significant, ongoing, and cost-effective energy savings and GHG reductions.

There are also several other promising approaches to behavior change, including online marketplaces that use behavioral prompts to help customers choose more efficient equipment, prepay billing programs, and mobile apps that provide real-time energy insights along with HER-type suggestions for improvement. These strategies still need to be better demonstrated before they can be widely adopted in DSM programs, but they show promise as an emerging area of focus.

Smart Thermostats and Advanced Commercial HVAC Controls

A smart thermostat is a type of Wi-Fi-enabled programmable thermostat designed for residential applications. Smart thermostats offer features intended to save energy and improve comfort by automatically adjusting heating and cooling temperature settings throughout the day. The specific approaches to saving energy can vary by product—for example, smart thermostats may learn users' temperature preferences and try to suggest an efficient temperature setback schedule; they may use occupancy sensors or geofencing (which tracks a user's smart phone location) to reduce HVAC energy waste when users are away from home; they may use optimization algorithms to adjust temperature schedules automatically over time to be more energy-efficient; or they may offer behavioral prompts to help users choose more efficient settings. In practice, they typically use a combination of these approaches. Although savings can vary by climate, savings approach used, and other factors, utilities have generally seen gas savings in the 10% range in their evaluations. Additionally, the ENERGY STAR program offers qualification criteria for smart thermostats[41] that prove their energy-saving capabilities based on anonymized field data.

In commercial applications, particularly those without an existing building automation system, connected thermostats and other advanced HVAC controls can make it easier for facility managers to set up efficient temperature schedules for multiple thermostats in a building (or a campus of buildings) and monitor performance over time through a central online portal or mobile app. These HVAC controls can also be part of more comprehensive control systems that encompass other major end uses like lighting or plug loads. Commercial connected thermostats often don't offer the same kinds of features as their residential "smart" counterparts, and more research is needed to better establish typical savings. Still, they can nonetheless be an effective approach to saving energy.

41 https://www.energystar.gov/products/heating_cooling/smart_thermostats

Other advanced HVAC controls can facilitate savings by controlling ventilation rates based on occupancy or dynamic air balancing to improve occupant comfort while minimizing energy waste. And some of these approaches can be especially effective. For example, research from Pacific Northwest National Laboratory suggests that whole-building energy savings of 18% (averaged across all U.S. climate zones) can be realized through the use of occupancy-based ventilation controls.[42]

High-Efficiency Cooking Equipment

There are numerous opportunities to choose gas cooking equipment with higher efficiencies, particularly for commercial food service equipment (such as ovens, fryers, broilers, and burners). ENERGY STAR's qualification criteria for commercial food service equipment[43] offer an easy way to identify equipment that's often 15-30% more efficient than standard models. Organizations like the Food Service Technology Center[44] provide additional resources and support for identifying additional cooking measures.

Commissioning and Retrocommissioning

Commissioning is the process of verifying that building systems are installed properly, behaving as expected, and operating efficiently. In existing buildings that have not been previously commissioned, or older buildings that are no longer operating at their design levels, the process is referred to as retrocommissioning. Studies from organizations such as Lawrence Berkeley National Laboratory have consistently found that commissioning and retrocommissioning are highly cost-effective for building owners, with whole-building (gas and electric) savings in the 10-20% range and simple payback periods as short as a year.[45] Commissioning also typically offers significant non-energy benefits to building occupants, such as improved comfort and indoor air quality. Another more recent approach is monitoring-based commissioning, which uses sensors and software to monitor building systems continually and ensure that they're operating as efficiently as possible. Because this approach reduces the chance of systems gradually becoming less efficient over time after the initial commissioning process, it eliminates the need for regular recommissioning every few years and offers the potential to yield larger energy savings that persist for longer than traditional commissioning processes.

Heat Recovery

Once heat is created using fuel such as natural gas, heat recovery can help ensure that it is used to its fullest potential and is not unnecessarily wasted. There is a wide range of approaches to heat recovery, several of which include:

- Drain water heat recovery can help reduce hot water energy consumption in residential and certain commercial applications by more than 30% by recapturing waste heat in the water going down the drain.
- Energy- and heat-recovery ventilation systems (ERV and HRV, respectively) transfer heat and (in the case of ERV) humidity between the incoming and outgoing air streams in an HVAC system. These systems reduce the need for additional space conditioning and dehumidification and can yield more than 25% HVAC energy savings for residential and commercial buildings in extreme climates.

42 https://www.pnnl.gov/publications/nationwide-hvac-energy-saving-potential-quantification-office-buildings-occupant
43 https://www.energystar.gov/products/commercial_food_service_equipment
44 https://fishnick.com/
45 https://cx.lbl.gov/documents/2009-assessment/lbnl-cx-cost-benefit.pdf

- Flue/stack heat recovery systems pull heat out of exhaust air streams from furnaces, boilers, or other combustion systems and can reduce energy consumption by 5-30%.
- Miscellaneous heat recovery for industrial processes can help maximize how a heat source can be utilized and reduce overall energy consumption.

ENERGY STAR-Qualified Products

ENERGY STAR is a widely recognized program that offers certification criteria for a range of products that can help reduce natural gas demand. It includes standardized savings assumptions that can make them relatively straightforward to include in DSM programs.[46] For instance, it includes criteria for building shell components (such as windows and doors), space and water heating equipment, clothes dryers, smart thermostats, and commercial food service equipment. ENERGY STAR-qualified products are typically designed to offer 10-50% energy savings compared to baseline equipment.

Energy-Saving Kits

Many utilities offer free or low-cost kits with a range of products intended to help customers save energy, such as faucet aerators, efficient shower heads, and pipe insulation. These kits can either be self-installed by customers or directly installed by contractors or trade allies as part of an in-home consultation or home energy audit. In addition to offering modest energy savings, these kits also serve as an excellent platform to share information on other efficiency offerings, online utility marketplaces, or other resources to help customers reduce their gas consumption.

Photo courtesy of www.bchydro.com

Combined-Heat and Power (CHP)

Combined Heat and Power (CHP) systems recover and utilize thermal energy and offer energy and GHG emissions reductions compared with on-site space or water heating and traditional utility power production. In CHP installations, the thermal heat lost (and wasted) during conventional utility-scale power generation is instead captured and used to provide on-site heating. Therefore, CHP systems must be local and sited near the location where the heat is used to utilize the thermal energy byproducts (heat) productively.

As long as fossil fuels power the marginal source of power generation, CHP is expected to reduce overall GHG emissions associated with electricity demand because it will continue to displace fossil fuel power on the margin. Natural gas CHP systems will always result in fewer emissions than separately-generating heat and grid power, even when compared to the most efficient combined-cycle gas turbine plants, as long as the displaced generation is from fossil fuel.

CHP is also favored by critical infrastructure, like hospitals, due to its significant reliability and resiliency advantages over the electric grid. This was recognized by the U.S. Department of Energy's Combined Heat and Power for Resiliency Accelerator.[47] Those advantages could become even more significant given the various emergent challenges associated with climate change and a rapid transition to a net-zero emissions future.

CHP units are also already being marketed by some companies as hydrogen compatible—able to transition to different lower carbon gases over time in support of net-zero objectives.

46 https://www.energystar.gov/

47 https://betterbuildingssolutioncenter.energy.gov/accelerators/combined-heat-and-power-resiliency

3.1.2 EMERGING GAS TECHNOLOGIES

In addition to the relatively well-established efficiency measures described above, several emerging gas technologies may offer substantial new opportunities for emission reductions. These include gas heat pumps, which have made inroads in the commercial sector over the past several years and which the gas industry expects to be on the market in all sectors by 2025. Also featured here are hybrid gas-electric heating systems, an arrangement that pairs a gas furnace with an electric air-source heat pump.

Gas Heat Pumps

Natural gas heat pumps are a promising technology currently available in the commercial sector and in the early stages of commercialization in the residential sector. Gas-fired heat pumps use thermal energy to drive a refrigeration cycle to provide space heating and cooling, water heating, or even clothes drying. Because they move heat, rather than relying solely on combustion, natural gas heat pumps have efficiencies of more than 100%. The efficiency of gas and electric heat pumps is measured using the coefficient of performance (COP) – the higher the COP, the more efficient the unit. Some currently available gas heat pumps offer COPs as high as 2.2, though most estimates of expected COPs are around 1.3 to 1.4. When just heating is considered, a 1.4 COP would represent a potential reduction in gas consumption of roughly 36% relative to a 90% efficient gas furnace and a 44% gas reduction compared with a baseline 78% efficient furnace that meets the current minimum federal efficiency standards.

Three different configurations of natural gas heat pumps are currently available:

- **Sorption heat pumps:** Absorption or adsorption heat pumps use thermal energy from gas combustion to drive a refrigeration cycle, typically using comparatively benign refrigerants like ammonia and water in lieu of traditional options.
- **Engine-driven heat pumps:** These are an older style of gas heat pump that uses a small internal combustion engine (similar to the electric motor in an electric heat pump) to physically move refrigerants through a refrigeration cycle.
- **Thermal compression heat pumps:** Also called Vuilleumier heat pumps, these essentially use a large piston that moves in response to thermal energy from gas combustion. They don't use traditional refrigerants, but instead use gases like helium or CO_2 as working fluids.

Photo of residential gas heat pump water heater from field trial.

A variety of products will likely continue to emerge in the coming years to meet a growing range of residential and commercial needs. Some units provide just space heating, some provide both space heating and cooling, and others are being developed to provide both space and water heating to a building. Each of these approaches has unique benefits and drawbacks with regards to characteristics such as size, cost, heating or cooling capacity, noise level, maintenance, refrigerant global warming potential (GWP), and efficiency.

Particularly when compared with electric heat pumps, gas heat pumps have the potential to offer several benefits to customers and utilities alike, including:

- High heating performance even at very low temperatures without needing to rely on supplemental heat sources (and without adding the strain of large spikes on the electric grid from winter space heating on very cold days)
- Lower operating costs than any other alternative heating systems—including electric heat pumps—due largely to the high efficiencies offered combined with the lower cost per BTU of energy delivered for natural gas compared with electricity
- Reduced GHG emissions in regions where the electricity supply relies primarily on fossil generation, in colder climates where emissions-intensive electric peaker plants are needed to meet winter loads, or where low/no-carbon gas supply is available.
- For certain customers (particularly in older homes), avoidance of electric panel upgrades and ductwork upgrades that may otherwise be needed for electric space heating
- In the case of sorption heat pumps, reduced maintenance resulting from having fewer moving parts
- For sorption and thermal compression heat pumps, the opportunity to move away from relatively high GWP refrigerants, further reducing lifetime GHG emissions for the system

Overall, given the substantial energy, emissions, and customer benefits, as well as the many active commercialization efforts currently underway, gas heat pumps represent a compelling opportunity for natural gas utilities to expand DSM programs and support even deeper reductions in customer gas demand in the coming years.

Hybrid Gas-Electric Integrated Space Heating System

Hybrid heating systems, sometimes referred to as dual fuel systems, consist of an electric air-source heat pump paired with a natural gas furnace and utilizes integrated controls that can optimize the energy consumption, emissions, and cost of the system throughout the year.

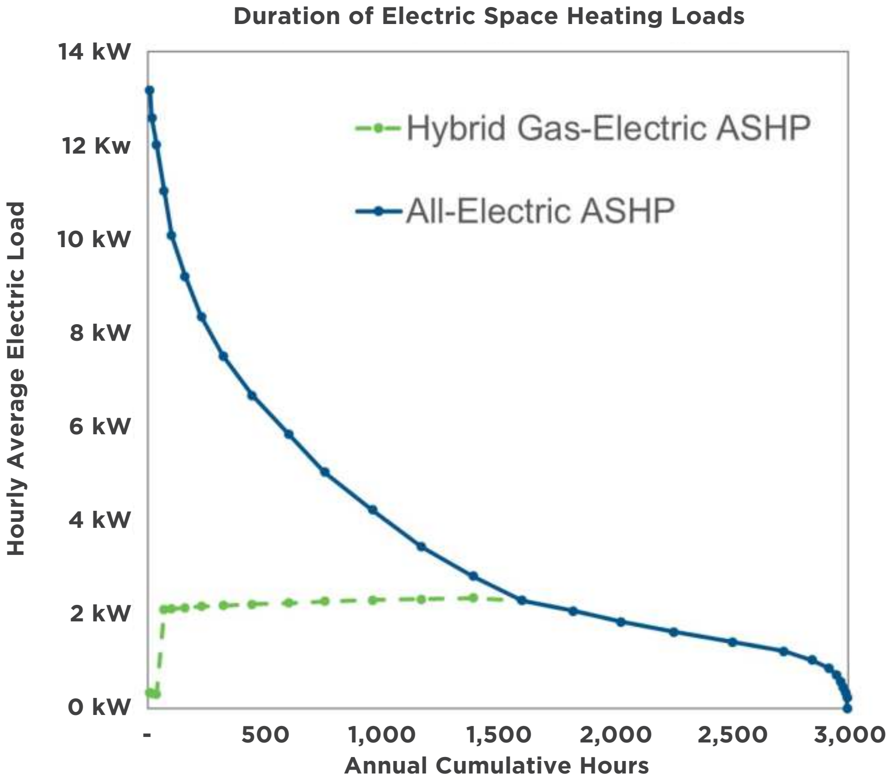
Electric air-source heat pumps (ASHPs) can have efficiencies as high as 300-400% but their performance degrades as the outdoor temperature drops. Falling temperatures increase the temperature differential that must be achieved by the heat pump, and affect heat pump performance in three ways:

- The heat pump's coefficient of performance (COP) decreases, so it becomes less efficient
- The heat pump has reduced output capacity, so it provides less heat
- The discharge air temperatures of the heat pump decrease.

At very low temperatures, heat pumps typically cannot provide adequate heat and require some form of supplemental or back-up energy – typically less efficient electric resistance heating. While the performance of cold climate ASHPs continues to improve, the low temperatures possible during cold snaps in many regions continue to necessitate supplemental heating in most cases.

As illustrated in **Exhibit 8**,[48] the need for back-up electric resistance heating significantly drives up the electricity required to heat a home as temperatures drop, even if this is only for a relatively small number of the coldest hours in the year, raising important questions about the ability of electric infrastructure to accommodate higher levels of peak demand.

Exhibit 8 – Example of Variability in ASHP Load



In a hybrid heating system, the heat delivery systems can be programmed to switch from the electric air source heat pump to the natural gas furnace below a balance point temperature.

This approach allows for a number of potential benefits:

- If power generation is decarbonized and few low-carbon gases have been added to the gas system, carbon emissions can be significantly reduced by using the ASHP to offset much of the heating loads on the gas system.
- A hybrid approach reduces electric demand spikes in the winter (particularly when the use of electric resistance heating can be avoided entirely)—for instance, in the example in Exhibit 8 electric demand from a hybrid ASHP peaks a bit over 2 kW, whereas an equivalent ASHP with electric resistance back-up peaks as high as 13 kW.
- Focusing ASHP uptake on times when customers are replacing their air-conditioners, not their furnaces, may make it easier for them to adopt the technology (as opposed to trying to install an ASHP when a furnace breaks down and the quickest way to restore heat is simply to install a new furnace rather than replacing the air conditioner and furnace at the same time).

48 Adapted from MaRS Future of Home Heating study, available at: https://marsdd.ca/research-and-insights/future-of-home-heating/

- Having multiple heating fuel sources may add flexibility, redundancy, and resiliency compared with an electric-only approach.
- There may be the potential to control hybrid systems based on real-time signals in order to achieve a more optimized energy system. For instance, if an electricity grid is experiencing a period of low levels of renewable generation from intermittent sources such as wind and solar, it could be possible for the hybrid systems to be switched to gas heating in order to shed electric load and avoid electric shortages.

A hybrid approach also faces a number of significant challenges as well. For instance, it may involve higher upfront costs than current heating equipment, and it may raise energy bills for customers when compared with a natural gas-only heating system. These systems will also likely require new regulatory approaches to accommodate in utility DSM programs. There would likely be a need to study how to recognize the value of gas and electric utility systems to allocate costs appropriately and compensate customers equitably since this approach would significantly shift the gas utility operating model. For example, this approach would see gas utilities continue to bear the costs and risks of meeting peak heating loads (to avoid challenges/costs on the electric side), but would also see a significant reduction in annual gas usage, and the associated utility revenue that supports the ability to serve those challenging peaks. This would also represent a fundamental change from an operations perspective – requiring utilities and regulators to re-evaluate how they maintain their system and procure gas supply. There may also be opportunities for gas and electric utilities to partner around combined DSM programs for hybrid space heating systems to maximize program cost-effectiveness for both parties.

Micro CHP

Unlike traditional CHP systems that are primarily targeted at commercial and industrial facilities, there are a variety of smaller CHP units with capacities ranging from less than 1 kW to 50 kW of electrical generation that could be applicable to residential and small commercial applications. As with larger CHP systems, micro CHP has the potential to reduce emissions associated with both heating and electricity consumption by producing both on-site from a single fuel (such as natural gas) and reducing the waste heat involved with the electric generation process. In residential applications, micro CHP can help meet both space and water heating needs while producing low-cost electricity that can offset consumption from the grid. Micro CHP can be particularly well-suited to replacing gas boilers since both systems tend to be available in similar sizes and orientations. Particularly in heating-dominated climates where broad electrification efforts may lead to larger winter peak demand on the electric side, micro CHP may be especially valuable for its ability to meet building heating loads while simultaneously reducing electric demand and overall emissions. Micro CHP systems may also be appealing for microgrid applications (where they can be treated as efficient grid assets) and in buildings where power reliability and resilience are a priority.

3.2 DECARBONIZATION OF GAS SUPPLY

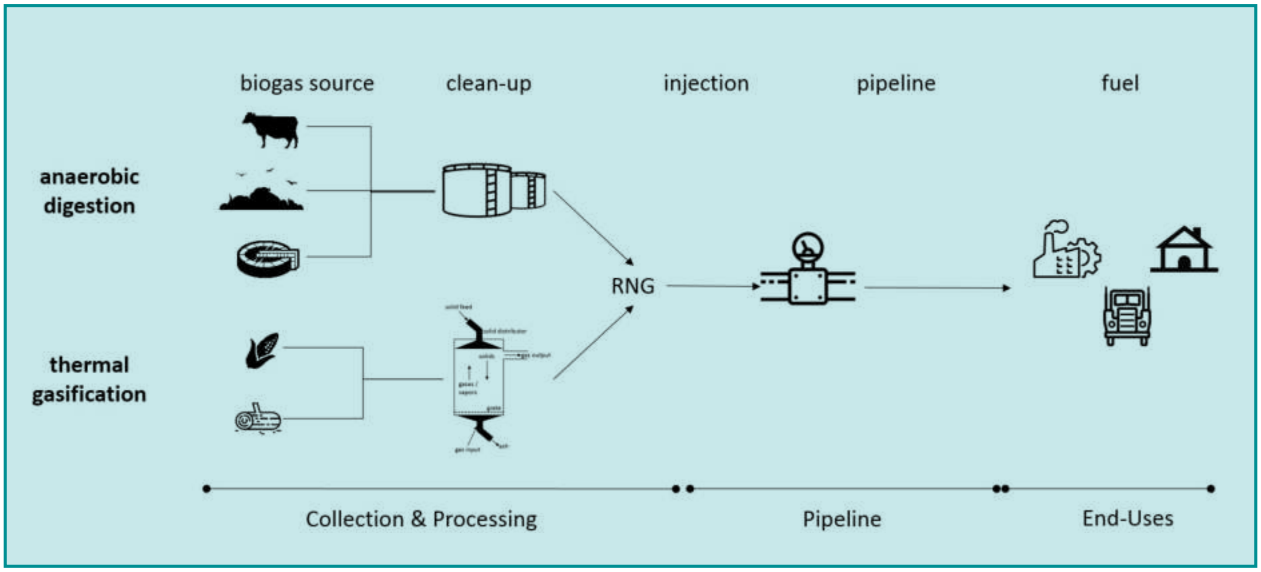
There are several alternatives to geologic natural gas that can be supplied through existing gas infrastructure but result in low or no net carbon emissions when combusted by utility customers. These renewable and low carbon alternatives include renewable natural gas and hydrogen, as well as 'synthetic' RNG produced from hydrogen (referred to as methanated hydrogen in this study). All provide long-term, annual storage solutions and can leverage the existing gas distribution infrastructure.

3.2.1 RENEWABLE NATURAL GAS

RNG is derived from biomass or other renewable resources and is a pipeline-quality gas that is fully interchangeable with conventional natural gas. The AGA defines RNG as pipeline-compatible (after processing) gaseous fuel derived from biogenic or other renewable sources that has lower life cycle carbon dioxide equivalent (CO_2e) emissions than geologic natural gas.[49]

As shown in **Exhibit 9**, RNG is produced over a series of steps: collection of a feedstock, delivery to a processing facility for biomass-to-gas conversion, gas conditioning, compression, and injection into the pipeline. Once the biogas is conditioned and upgraded, and eligible for pipeline injection, it is called RNG. Finally, once injected into the pipeline, RNG is indistinguishable from geologic gas. In this project, ICF considers two production approaches: anaerobic digestion (AD) and thermal gasification (TG).

Exhibit 9 – RNG Production Process via Anaerobic Digestion and Thermal Gasification



49 ICF notes that this is a useful definition, but excludes RNG produced from the thermal gasification of the non-biogenic fraction of municipal solid waste (MSW). MSW, specifically the non-biogenic waste that would be landfilled after diversion of organic waste products, like plastics, is included as an RNG resource in this study even though it does not satisfy the AGA's definition of RNG, as is explained further in **Section 4.4.1**.

Anaerobic Digestion

The most common way to produce RNG today is via anaerobic digestion, whereby microorganisms break down organic material in an environment without oxygen. The four key processes in anaerobic digestion are:

- **Hydrolysis**
- **Acidogenesis**
- **Acetogenesis**
- **Methanogenesis**

Hydrolysis is the process whereby longer-chain organic polymers are broken down into shorter-chain molecules like sugars, amino acids, and fatty acids that are available to other bacteria. **Acidogenesis** is the biological fermentation of the remaining components by bacteria, yielding volatile fatty acids, ammonia, carbon dioxide, hydrogen sulfide, and other by-products. **Acetogenesis** of the remaining simple molecules yields acetic acid, carbon dioxide, and hydrogen. Lastly, **methanogens** use the intermediate products from hydrolysis, acidogenesis, and acetogenesis to produce methane, carbon dioxide, and water, where most of the biogas is emitted from anaerobic digestion systems.

The process for RNG production through AD generally takes place in a controlled environment, referred to as a digester or reactor, including landfill gas facilities. When organic waste, biosolids, or livestock manure is introduced to the digester, the material is broken down over time (e.g., days) by microorganisms, and the gaseous products, referred to as biogas, of that process contain a large percentage of methane and carbon dioxide. The biogas is captured and then requires subsequent conditioning and upgrading before pipeline injection. The conditioning and upgrading helps remove contaminants and other trace constituents, including siloxanes, sulfides, and nitrogen that cannot be injected into common carrier pipelines, and increases the heating value of the gas for injection.

Thermal Gasification

Biomass-like agricultural residues, forestry and forest produce residues, and energy crops have high energy content and are thus ideal candidates for thermal gasification. The thermal gasification of biomass and non-biogenic MSW to produce RNG occurs over a series of steps:

- Feedstock pre-processing in preparation for thermal gasification (not in all cases).
- Gasification, which generates synthetic gas (syngas), consisting of hydrogen and carbon monoxide (CO).
- Water-gas shift reaction that generates more hydrogen and carbon dioxide.
- Filtration and purification, where the syngas is further upgraded by filtration to remove remaining excess dust generated during gasification, and other purification processes to remove potential contaminants like hydrogen sulfide, and carbon dioxide.
- Methanation, where the upgraded syngas is converted to methane (CH4) and dried prior to pipeline injection.

Gasification technology is at an early stage of commercialization. A handful of thermal gasification projects are in the late stages of planning and development in North America. For example, REN is proposing to build a modular thermal gasification facility in British Columbia using wood waste to produce pipeline-quality RNG for the local natural gas utility, FortisBC.[50] Sierra Energy's thermal gasification and biorefinery facility in Nevada produces RNG and liquid fuels using municipal solid waste as a feedstock.[51] West Biofuels have a number of demonstration and research projects using biomass to produce RNG, as well as commercialized thermal gasification facilities producing other renewable fuels.[52] Further afield there are demonstration and early-commercialization thermal gasification projects across Europe, including Sweden, France and Austria.[53]

ICF notes that biomass, particularly agricultural residues, are often added to anaerobic digesters to increase gas production (by improving carbon-to-nitrogen ratios, especially in animal manure digesters). It is conceivable that some of the feedstocks considered here could be used in anaerobic digesters. For simplicity, ICF did not consider any multi-feedstock applications in our assessment; however, it is important to recognize that the RNG production market will continue to include mixed feedstock processing in a manner that is cost-effective.

3.2.2 HYDROGEN PRODUCTION AND BLENDING

Hydrogen is an energy carrier; energy sources are used to create H_2, which can later be combusted or run through fuel cells to release its energy. The combustion of hydrogen produces no GHG emissions and, given the potential to produce hydrogen through low- and no-carbon pathways, it is increasingly seen as a valuable form of energy storage, delivery, and use. Hydrogen's functionality as a gas potentially makes it a high-value decarbonization resource for multiple end-uses currently met by fossil fuels. It can be blended into natural gas pipelines or transported through its own dedicated infrastructure—pipelines, tube trailers, or by conversion or liquefaction.

Clean hydrogen, which indicates low to no carbon emissions associated with production, can be produced through a variety of different processes. To help differentiate the source of clean hydrogen production, a color-coding system is often used for shorthand:

- **Green Hydrogen:** hydrogen produced via electrolysis from renewable energy
- **Blue Hydrogen:** hydrogen produced from steam methane reforming (SMR) with carbon capture and sequestration (CCS)
- **Pink Hydrogen:** hydrogen produced via electrolysis from nuclear energy

Steam methane reformation of geologic natural gas (gray hydrogen) is the conventional approach to hydrogen production. Natural gas reforming accounts for approximately 95% of U.S. commercial H_2 production today.[54] The process involves three key steps:

- Steam methane reforming uses a catalyst/heat input to react methane and steam to generate carbon monoxide and hydrogen
- A water-gas shift reaction takes the CO and steam to generate additional H_2 and carbon dioxide (CO_2)
- Pressure-swing adsorption removes impurities and CO_2 from the hydrogen stream

Other production methods for producing hydrogen from natural gas include partial oxidation and autothermal reforming.

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50 FortisBC, 2020. Filing of a Biomethane Purchase Agreement between FEI and REN Energy International Corp, https://www.bcuc.com/Documents/Proceedings/2020/DOC_57461_B-1-FEI-REN-Sec-71-BPA-Application-Confidential-Redacted.pdf

51 Sierra Energy, 2020. https://sierraenergy.com/projects/fort-hunter-liggett/

52 West Biofuels, 2020. http://www.westbiofuels.com/projects?filter=research

53 Thunman, H. et al, 2018. Advanced biofuel production via gasification - lessons learned from 200 years man-years of research activity with Chalmers' research gasifier and the GoBiGas demonstration plant. Energy Science & Engineering, 29.

54 Hydrogen and Fuel Cell Technologies Office, U.S. Department of Energy, n.d. Hydrogen Production: Natural Gas Reforming. https://www.energy.gov/eere/fuelcells/hydrogen-production-natural-gas-reforming

Due to its upstream emissions, gray hydrogen has higher life cycle greenhouse gas emissions intensity than natural gas.[55] Pairing hydrogen production from natural gas with carbon capture reduces the GHG emissions associated with the production of hydrogen. Blue hydrogen production (SMR with carbon capture) projects are being proposed with plans to capture as much as 95% of the resulting CO_2.[56]

Producing green hydrogen through electrolysis is a primary focus of the investment and R&D momentum for hydrogen as a decarbonization strategy. Electrolyzers split water into hydrogen and oxygen using electricity—power-to-gas (P2G). If the electricity is generated from renewable or nuclear sources, the electrolysis hydrogen production process is considered to have zero emissions.

Electrolysis has been a part of commercial hydrogen production for over 100 years and was discovered long before. The technology is well established. The focus of ongoing R&D is to make electrolysis production costs competitive with those of SMR. Today, there are three main electrolyzer technologies in different stages of development and implementation:

- Alkaline electrolysis,
- Proton exchange membrane (PEM) electrolysis, and
- Solid oxide electrolysis.

In addition to the production of hydrogen, approaches to facilitate the distribution and end-use of hydrogen are critical. Hydrogen has the potential to be blended into the natural gas supply, with a 20% volume blend (equivalent to 7% on an energy basis as hydrogen is less energy dense per unit volume than natural gas) commonly discussed as an upper blending limit without requiring significant upgrades to customer equipment or the gas distribution system.[57] A number of hydrogen blending projects have been announced in U.S., including pilots by SoCalGas[58] and Dominion Energy.[59] To leverage higher percentages of hydrogen two options are methanating that hydrogen and building/converting gas infrastructure to be dedicated to 100% hydrogen use. These two approaches are discussed in the following sections.

3.2.3 METHANATED HYDROGEN

In addition to augmenting natural gas supplies via blending, hydrogen can be converted to methane and injected into the natural gas system. A growing opportunity to reduce methane emissions from the natural gas supply is through the production of RNG from P2G. RNG from P2G can be a net-zero alternative to geologic natural gas.

A methanation process is used to convert the hydrogen into methane. There are two key methanation reactions:

$$CO_2 + 4H_2 \rightarrow CH_4 + 2\ H_2O$$

$CO + 3H_2 \leftrightarrow CH_4 + H_2O$ (this is the Steam Methane Reforming reaction run backwards)

55 EPA Green Vehicle Guide | Fuels https://www3.epa.gov/otaq/gvg/learn-more-fuels.htm

56 Pembina Institute, Proposed hydrogen project a big improvement, 2021. https://www.pembina.org/media-release/proposed-hydrogen-project-big-improvement

57 https://www.nrel.gov/docs/fy13osti/51995.pdf

58 https://sempra.mediaroom.com/index.php?s=19080&item=137866

59 https://www.dominionenergy.com/projects-and-facilities/hydrogen#utah

Hydrogen can be converted into methane by using the CO_2 contained in the biogas resulting from anaerobic digestion of wastes (gas typically made of a large share methane and a smaller share of CO_2), creating a productive use for the CO_2 rather than having to scrub it from the biogas. Similarly, syngas from thermal gasification can serve as a biogenic carbon source. Leveraging thermal gasification as the carbon source for methanation also brings potential benefits achieved by co-locating electrolysis and gasification operations. As with AD gas, leveraging the CO and CO_2 in syngas with hydrogen increases RNG productivity. Plus, biomass gasification requires oxygen, which is a by-product of electrolysis that is typically wasted. Supplying gasifiers with a direct source of oxygen (rather than pulling it from the air, which is predominantly nitrogen) increases the purity of their RNG output and reduces gasification plant capital costs. Methanated hydrogen increases RNG supplies and avoids the cost and inefficiency associated with storing and distributing hydrogen.

Though methanation was invented over 100 years ago, power-to-gas hydrogen methanation is relatively new to the market. R&D into hydrogen methanation has demonstrated its potential to grow overall renewable natural gas supplies significantly. Across the world, from Belgium, Germany, Switzerland and other European countries to the U.S. and Japan (among others) projects have been testing the concept, with most projects having been developed since 2009. For example, Germany's Audi e-gas plant has been using offshore wind to power 6 MWe worth of electrolyzers partnered with biogas the generate synthetic RNG since 2013.[60]

3.2.4 DEDICATED HYDROGEN INFRASTRUCTURE

One approach that reduces the need for geologic natural gas is converting customers to dedicated hydrogen infrastructure. This involves either building new hydrogen-specific infrastructure or converting existing natural gas infrastructure to be used for hydrogen. Key barriers to overcome include hydrogen compatibility with existing infrastructure and addressing regulatory structure and safety considerations.

There are many factors that play into the safety of hydrogen systems. With consumer education, monitoring devices, and unification of safety standards for equipment, hydrogen has the potential to be used safely in new residential and commercial end uses. It has different flammability characteristics than methane, which means that additional (and different from natural gas) precautions are required for the safe management of the fuel. Regarding pipelines, according to an analysis conducted by GTI and summarized by NREL, lower blends of hydrogen into natural gas pipeline flows demonstrate a minor increase in risk, whereas flowing "more than 50% hydrogen to either distribution mains or service lines results in a significant increase in overall risk," which would necessitate risk management tools like increased monitoring. Still, new dedicated hydrogen pipelines could be designed and managed according to hydrogen's technical qualities and, therefore, not subject to the same concerns as converted natural gas pipelines.[61]

While several hydrogen blending projects have been announced in the U.S., in general, Europe has progressed further in planning its pathways to decarbonization and the supportive role that dedicated hydrogen infrastructure can play. One example of this is the European Hydrogen Backbone plan, shown in **Exhibit 10**, which lays out a plan to build an integrated hydrogen network across the continent through a mix of building new hydrogen pipelines and conversion of existing gas pipelines.[62]

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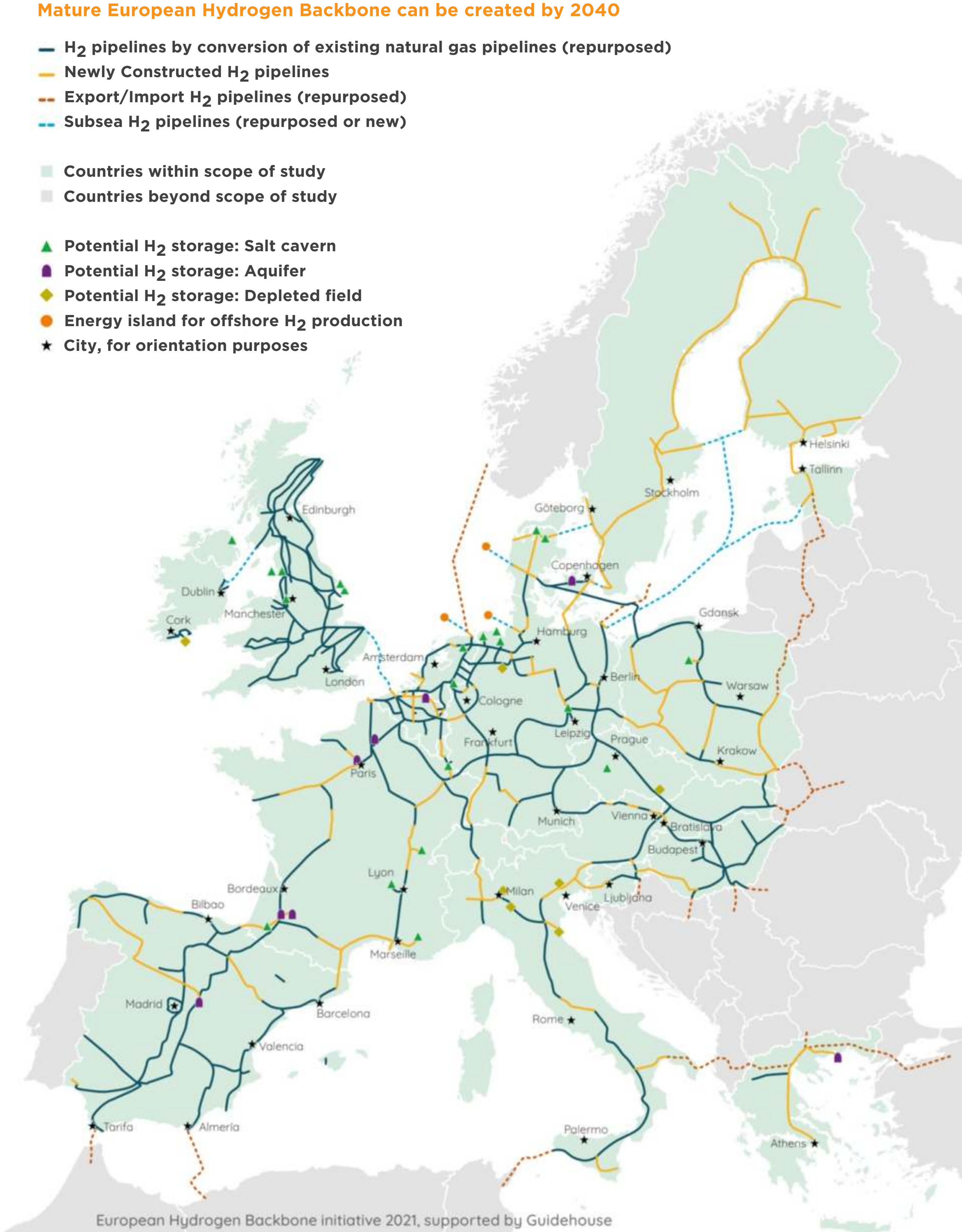
60 Bailera et al., Power to Gas projects review: Lab, pilot and demo plants for storing renewable energy and CO_2, 2017. Available at https://www.sciencedirect.com/science/article/pii/S1364032116307833

61 https://www.nrel.gov/docs/fy13osti/51995.pdf

62 Enagás, Energinet, Fluxys Belgium, Gasunie, GRTgaz, NET4GAS, OGE, ONTRAS, Snam, Swedegas, Teréga (European Hydrogen Backbone) supported by Guidehouse, 2020. https://guidehouse.com/insights/energy/2020/developing-europes-hydrogen-infrastructure-plan

Exhibit 10 – European Hydrogen Backbone Map, Produced by Guidehouse



European Hydrogen Backbone initiative 2021, supported by Guidehouse

In pursuit of its 2050 carbon dioxide emission targets, the UK's Department for Business, Energy & Industrial Strategy coordinated a 'Hydrogen for Heat' (Hy4Heat) program, a three-year study beginning in late 2017 to evaluate the feasibility of displacing natural gas use in residential and commercial appliances with hydrogen.[63] Hy4Heat's work packages include two initiatives to develop domestic and commercial hydrogen appliances. These packages focus on understanding the opportunities and challenges presented by converting natural gas equipment to hydrogen appliances and delivering prototype H2 appliances that are safety-certified along with compatible ancillary equipment.[64] Developments have moved faster on the residential side. Through the project, two show homes in Gateshead, England, using 100% hydrogen were developed with hydrogen boilers, cooktops, and fires and opened to the public in July 2021.[65] [66] The commercial hydrogen appliance work package determined that existing hydrogen boilers used in the industrial sector and faster-moving developments of residential H_2 appliances could demonstrate the potential for safety, efficiency and ultimate feasibility of scaled-up 100% hydrogen appliances for the commercial sector.[67] Further refining of novel hydrogen appliance technology in the domestic space will guide safety and efficacy design decisions for larger-scale commercial appliances. In some applications, our understanding of current natural gas technologies can guide the development of hydrogen versions. For example, some natural gas CHP manufacturers have modified their designs to accommodate 100% hydrogen.[68]

One R&D initiative underway in the U.S. is the Low-Carbon Resource Initiative (LCRI) which is a five-year joint effort between the Electric Power Research Institute (EPRI) and the Gas Technology Institute (GTI) to accelerate the development and demonstration of low-carbon energy technologies, including hydrogen as an energy carrier. LCRI emphasizes large-scale technology commercialization and deployment,[69] aiming to identify promising technologies worldwide with applications across the low-carbon energy value chain, demonstrate those technologies' performance, evaluate decarbonization pathways, and engage key stakeholders.[70] The LCRI demonstrates a recognition of the need to explore opportunities for gas & electric infrastructure to coordinate in support of decarbonization pathways.

Another U.S. hydrogen R&D project is the HyBlend initiative, a collaboration between six national laboratories and more than 20 participants from industry and academia led by the National Renewable Energy Laboratory (NREL) to address the technical barriers faced when blending hydrogen into natural gas pipelines. The project is divided into three main research areas: hydrogen compatibility of piping and pipelines, life-cycle analysis of technologies using hydrogen and natural gas blends, and techno-economic opportunities for hydrogen production and blending.[71] Utilities are also exploring the potential for hydrogen in their infrastructure, including plans to test their capability of running at 100% H_2.[72] [73]

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63 Arup, 2018. https://www.arup.com/projects/hy4heat

64 Hy4Heat Progress Report, 2020. https://www.hy4heat.info/s/2020-annual-report

65 UK Department for Business, Energy & Industrial Strategy, 2021. https://www.gov.uk/government/news/say-hy-to-the-home-of-the-future

66 Hydrogen Home Launch 15 July 2021 - YouTube

67 Hy4Heat, 2020. WP5 – Commercial appliances, https://www.hy4heat.info/s/ERM-FINAL-2020.pdf

68 2G Energy, 2021. https://www.2g-energy.com/products/hydrogen/

69 EPRI, 2021. https://www.epri.com/lcri

70 EPRI, Low-Carbon Resources Initiative (LCRI) Enabling the Pathway to Economy-Wide Decarbonization. https://www.epri.com/research/products/000000003002020041

71 HyBlend Project To Accelerate Potential for Blending Hydrogen in Natural Gas Pipelines | News | NREL

72 Pendrod, 2020. https://www.utilitydive.com/news/hydrogen-is-having-a-moment-and-power-generation-is-leading-the-way/587958/

73 Blunt, 2020. Utilities Look to Green Hydrogen to Cut Carbon Emissions, https://www.wsj.com/articles/utilities-look-to-green-hydrogen-to-cut-carbon-emissions-11599298201#:~:text=U.S.%20utilities%20are%20increasingly%20exploring,0.46%25%20and%20Dominion%20Energy%20Inc

3.3 OFFSETS, CARBON CAPTURE, AND NEGATIVE EMISSIONS TECHNOLOGIES

There are several technologies that can be leveraged to reduce GHG emissions, either directly from point sources in other sectors of the economy or extracted and sequestered CO_2 from the atmosphere. These technologies can enable economy-wide emission reduction pathways to reach net-zero, providing flexibility to companies and governments in pursuit of emissions reductions and climate targets. There is uncertainty on the timeline for some of these options, and the policy frameworks around some strategies and technologies are subject to change. Yet, certain technologies have the potential to develop into relatively cost-effective opportunities and play a role in the achievement of net-zero targets. A selection of technologies is described below.

3.3.1 CARBON CAPTURE, UTILIZATION, AND STORAGE

Carbon capture, utilization, and storage (CCUS) offer a climate change mitigation solution by removing CO_2 from point sources or the atmosphere and storing it underground.[74] Current operational CCUS-equipped power plants and large industrial facilities can reduce around 90%[75] of CO_2 emissions according to their original design. But, it is technically feasible to design future plants with the capacity to remove 99% or more emissions using the same existing technologies.[76] There are a variety of CO_2-capture approaches that fall under the CCUS umbrella. Carbon can be captured from a large point source such as a new or existing gas-fired power plant, municipal solid waste landfill, manure management system, or industrial source involving fossil fuel or biomass use, hydrogen production, among other sources. These volumes of captured CO_2 can be permanently stored in deep geological formations. In addition, CO_2 can be used onsite for enhanced oil and natural gas recovery or transported and used in different applications in the medical, agricultural, and industrial sectors.

CCUS technologies have the potential to capture CO_2 from a fossil power plant before the conventional combustion is completed (pre-combustion), as showcased through recent pilot projects. This technology was, for the first time, tested in Porte, Texas, at a natural gas power plant owned by NET Power LLC. The facility operates with an Allam Cycle, which leverages oxy-combustion by burning natural gas with pure oxygen instead of air while capturing the generated CO_2 and water. Most of the high-pressure CO_2 is contained and reused to spin the turbine, so it isn't released into the atmosphere.[77]

In addition, CO_2 emissions can be captured post-combustion by pulling out CO_2 of flue gases from combustion exhaust or process stream. The oil and gas industry is one of the earlier adopters of this technology. It has been deploying post-combustion capture since the 1970s in the U.S. In some cases, the separated CO_2 is stored permanently through underground injection and geologic sequestration into deep underground rock formations.[78] These formations are often a mile or more beneath the surface and consist of porous rock that holds the CO_2. Overlying these formations are impermeable, non-porous layers of rock that trap the CO_2 and prevent it from migrating upward.[79]

Another option to capture CO_2 post-combustion is directly from the atmosphere through direct air capture (DAC) technologies. Similar to other carbon capture technologies, a DAC system uses chemical reactions to selectively remove CO_2 from air when it passes through a solid sorbent filter or a liquid system while returning the rest of the air to the environment; the difference between DAC and other carbon capture technologies is that this process is applied directly to ambient air.[80] DAC technologies are currently under development, with a focus on increasing efficiencies and decreasing costs for large-scale use.

74 Carbon-Removal-with-CCS-Technologies.pdf (globalccsinstitute.com)
75 https://www.c2es.org/content/carbon-capture/
76 CCUS in Power – Analysis - IEA
77 Technology | NET Power - Making Clean Cheaper Than Dirty
78 Brief-_CCS-in-OAG-3.pdf (globalccsinstitute.com)
79 https://19january2017snapshot.epa.gov/climatechange/carbon-dioxide-capture-and-sequestration-overview_.html
80 Direct Air Capture – Analysis - IEA

Bioenergy carbon capture and storage (BECCS) is another negative-emissions technology option under consideration that involves capturing the CO_2 from power plants or industrial processes that are using biogenic fuels (and hence would have been considered carbon-neutral even without CCUS). The utilization of the gas CO_2 capture system to support the combination of CCS and renewable gases could support net negative emissions outcomes.

The CO_2 captured that isn't sequestered underground can be utilized in different ways. The oil and gas industry widely uses it to produce oil through the enhanced oil recovery (EOR) process (recompressed CO_2 is reinjected into the reservoir where it expands, pushing additional oil towards production wells). It also can be compressed and transported to another facility, usually in pipelines or ships, to be used in the creation of a variety of products that include construction materials, plastics, chemicals, and algae-based products. Some of these alternative uses are currently in the early stages of development, and it is expected they will offer a significant potential to contribute to greenhouse gas reduction in the coming decades.[81]

CCUS plays a significant role in IEA's Net-zero by 2050 Scenario. In this decarbonization pathway, IEA estimates that, by 2050, 22% of worldwide emissions reduction to net-zero comes from CCUS, relative to 2020 total emissions. From that estimate, 95% is stored in permanent geological storage, and 5% is used to provide synthetic fuels, including carbon captured from fossil fuels and processes, bioenergy plants, and direct air capture.[82] To capture those levels of CO_2, an expansion in the number of projects planned and in operation is needed. Currently, there are 26 commercial-scale carbon capture projects operating around the world, including some natural gas processing projects. In addition, 21 projects are in an early stage of development, and 13 are in advanced development.[83]

Currently, there are no large-scale operational projects for direct air carbon capture. The first large-scale plant is being developed in the United States; the Carbon Engineering plant is planned to capture one million metric tons of CO_2 for use in enhanced oil recovery and is expected to begin operations in 2023. Given that this technology isn't yet demonstrated at a large scale, carbon removal costs are uncertain.[84]

3.3.2 GHG EMISSIONS OFFSETS

A carbon offset[85] occurs when GHG emissions reductions at one location are used to "offset" the equivalent amount of GHG emissions from another location or project. Emission reductions that are certified by a verified third-party are widely accepted as high-quality offset credits that can be bought, sold, or traded in carbon offset markets. The carbon offset approach to capturing the value of emission reductions can be used as a market mechanism for many different types of projects. Some examples of carbon offsets are:

- Credits from improving forest management projects
- Credits from livestock projects
- Credits from urban forest projects associated to tree planting and maintenance activities to permanently increase carbon storage in trees
- Credits from the destruction of high global warming potential ozone depleting substances that would have otherwise been released to the atmosphere

81 Carbon Utilization— A Vital and Effective Pathway for Decarbonization Summary Report (c2es.org)

82 https://www.iea.org/reports/net-zero-by-2050

83 https://www.c2es.org/content/carbon-capture/

84 https://www.iea.org/reports/direct-air-capture

85 A carbon offset is a reduction in emissions of carbon dioxide or other greenhouse gases made in order to compensate for ("offset") an emission made elsewhere. https://www.ipcc.ch/2018/06/15/ipcc-meetings-go-carbon-neutral/

- Credits from restoring a U.S forest that include improved forest management, avoided conversion, and reforestation
- Credits from avoiding methane or other GHG emissions from an industrial or agricultural process
- Nature-based solutions like allowing forests to regrow, restoring coastal wetlands, and switching to restorative agricultural practices[86]

Strict protocols are applied to ensure that the reductions are "additional." Namely, that they are actual reductions that would not have occurred but for the offset project. Among other things, this means that the reductions cannot be the result of regulation or other existing requirements. The reduction in greenhouse gas emissions from these projects counts toward the balance of the entity buying the offset, rather than the entity installing the project or the place it's built.

Consumers can purchase offsets to mitigate their routine emissions for home use or travel. Some gas utilities are piloting programs through which gas customers can voluntarily decide to purchase offsets covering a portion of their emissions from gas use.[87] Their voluntary nature facilitates regulatory approval (no customers are being forced to purchase offsets). While similar programs represent a pathway to finance initial emissions reductions efforts for gas utilities, they do not replace the need to reduce customer emissions, which is the focus of the pathways in this study.

Strict offset quantification and certification protocols exist to provide confidence that GHG emissions reductions are achieved. Following the protocols, emissions reductions projects can be turned into creditable and transferrable emission offsets. Protocol guidelines establish that GHG reductions must be below the emissions that would otherwise have occurred and in addition to reductions already occurring or required by regulation and must be carefully and transparently measured and verified.

The offsets' certification process is as follows: Once a project has been identified, the developer identifies an appropriate offset creation protocol from one of the certification organizations such as the U.N. Clean Development Mechanism, the Climate Action Reserve, the American Carbon Registry, or other similar organizations. The developer submits the required analysis and data on the project to the certifier. If the project qualifies, the developer can periodically submit the data to quantify and be awarded creditable offsets. The original certification would ensure that the reductions meet the qualitative criteria and establish the parameters for ongoing quantification. These protocols ensure that the offsets are based on accurate and verifiable reductions that would not have otherwise been achieved. Offsets of this kind are widely accepted in emission cap and trade programs such as the California, NESCAUM, and European Union cap and trade programs.

86 https://ww2.arb.ca.gov/our-work/programs/compliance-offset-program/arb-offset-credit-issuance

87 https://solutions.dteenergy.com/dte/en/Products/DTE-CleanVision-Natural-Gas-Balance-LVL-1/p/NATURAL_GAS_BALANCE_LEVEL_1?utm_campaign=natural+gas+balance&utm_medium=vanity+url&utm_source=universal

3.4 METHANE EMISSION REDUCTION MEASURES

The previous sections have focused on strategies to reduce the CO_2 emissions from the combustion of geologic natural gas by utility customers or to offset those emissions. This section introduces opportunities to reduce methane emissions from gas utility operations and upstream production, processing, and transportation of geologic natural gas. Methane emission reductions are critical due to methane's higher global warming potential than CO_2 and because these represent the largest component of the direct emissions from gas utilities – emissions under their control.

3.4.1 GAS UTILITY EMISSIONS

The primary sources of direct GHG emissions for gas utilities are fugitive and vented methane emissions and CO_2 from combustion for storage compressors, on-site generators, and fleet operations. The methane emissions are typically the much larger share and on a national basis comprise nearly 85% of the GHG emissions from natural gas distribution. Over 90% of the methane emissions typically are from:

- Gas mains and services
- Meters/meter sets
- Third-party damage to pipes (also known as dig-ins or mishaps)

These emission estimates are typically based on factors the U.S. EPA has adopted for the Greenhouse Gas Reporting Rule (GHGRP)[88] or the annual national Inventory of U.S. Greenhouse Gas Emissions and Sinks (EPA GHGI).[89] The emission factors were typically developed in studies over the years, in which methane emissions from a sample of pipes or a given type of equipment were measured and averaged. The resulting emission factor represents the average emissions from that category of pipe or equipment at the time of the study. Most methane emission estimates are developed by multiplying these average, fixed emission factors by "activity factors" that represent equipment counts (miles of pipe, number of meters, etc.). This approach is limiting because the only way to reduce the emissions estimate is to reduce the counts (e.g., number of meters or miles of pipe), so measures that reduce actual emissions from existing equipment are not accounted for in the estimate. In addition, more accurate company-specific data reflecting actual emissions reductions cannot be incorporated. The limitations of the existing approaches point to the value in developing company-specific emissions factors to better account for emissions-reduction efforts.

88 GHGRP: https://www.epa.gov/ghgreporting

89 GHGI: https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks

With this caveat, the most significant pathways for reducing actual (as opposed to estimated) emissions typically are as follows:

- **Pipes** – There are different emission factors for different pipe materials. Replacing the higher-emitting types of pipe (cast iron and unprotected steel) with lower-emitting types of pipe that also have a lower emission factor (protected steel and plastic) is the primary existing option to reduce both actual and estimated emissions. Going beyond this pipeline replacement, companies can reduce actual emissions by incorporating leak detection and reduction programs. Reflecting the resulting emission reductions in estimates will require developing company-specific emission factors, which some companies are pursuing. In addition, gas utilities can reduce methane emissions by replacing the higher emitting vintage plastic pipe with modern polyethylene (PE) pipe. The resulting emission reduction could be demonstrated in emission estimates either with company-specific emission factors or by developing updated emission factors for PE plastic pipe.

- **Meters** – Since the standard emissions estimates, based on industry average emissions factors multiplied by meter counts, would not be reduced even if a company eliminated all meter leaks, accounting for reduction programs requires the development of company-specific emission data. This can be done through direct measurement as part of meter integrity programs combined with leak detection and repair (LDAR) programs. Direct measurement programs would provide more accurate estimates and help to document and recognize reductions made through these programs.

- **Excavation Damage / Mishaps** – Similar to meters, company-specific data can provide more accurate estimates than the standard mileage-based factors and document company emission reduction programs. Many companies estimate actual emissions from mishaps and this information can be used to develop more accurate estimates.

- **Other Operational and Maintenance Measures** – There is a variety of O&M measures that can help to reduce methane emissions. Leak detection and repair (LDAR) are standard parts of LDC operations and could include meter and regulator (M&R) stations and gas storage facilities. Expanded LDAR programs can reduce methane emissions but must be coupled with measurement and documentation to account for the reductions. Blowdowns (managed releases of gas) are required for a variety of maintenance and repair operations. A variety of techniques are available to reduce or eliminate these releases, which again must be measured and documented.

- **Replacement of Higher Emitting Equipment** – There are other types of equipment in addition to pipelines that can be replaced to reduce emissions. One common option is the replacement of high bleed pneumatic controllers with lower-emitting or "no-bleed" equipment.

All of these topics are addressed in more detail in **Section 4.6** of this report.

3.4.2 UPSTREAM NATURAL GAS EMISSIONS

There are opportunities across the U.S. oil and gas industry value chain to reduce emissions of methane significantly.[90] Some utilities are examining their gas supply procurement practices to account for environmental performance criteria across the value chain. There are several labels used for natural gas products meeting such criteria, including 'differentiated gas,' 'responsibly sourced gas,' and 'certified gas.' All these approaches focus on acquiring geologic natural gas with a minimized emissions footprint that has been verified. Certification criteria are typically focused on methane emissions, but some also consider additional qualities, including other air emissions or water use.[91]

Various entities have established certification programs for differentiated gas, although to date no standards exist. Some companies have already begun acquiring differentiated gas. For example, in 2018, Southwestern Energy entered into a bilateral contract[92] with New Jersey Natural Gas for natural gas produced at selected wells in the company's Marcellus play certified by IES' TrustWell™, and in June 2021, Southwestern Energy announced it is entering an arrangement to have all its natural gas production certified as "responsibly sourced gas" by Project Canary and IES TrustWell™. In May 2021, Xcel Energy announced[93] it agreed to buy TrustWell™ certified "responsibly sourced gas" natural gas for delivery to its customers in Colorado from Crestone Peak Resources. In addition, several producers in summer 2021 are piloting a MiQ (Methane Intelligence) certified low methane gas program based on the Natural Gas Sustainability Initiative methane intensity protocol.

The biggest obstacle for gas utility purchases of differentiated gas is the lack of regulatory approval to purchase natural gas at a cost premium. Most states have a regulatory prudency requirement for "least cost" gas supply acquisition that does not leave discretion for companies to select lower-emitting gas supplies, even if these amount to relatively cost-effective emission reduction measures on a $/t$CO_2$e basis.

90 https://www.edf.org/icf-methane-cost-curve-report
91 https://www.gti.energy/introducing-a-differentiated-gas-initiative/
92 https://marcellusdrilling.com/2018/09/southwestern-sells-1st-certified-responsible-gas-to-nj-resources/
93 https://www.reuters.com/business/energy/xcel-energy-strikes-deal-purchase-low-emissions-gas-colorado-2021-05-12/

4 NET-ZERO EMISSION PATHWAYS

This study is intended to explore several illustrative pathways to net-zero for gas utilities but does not attempt to predict what is most likely to happen by 2050, nor to determine the lowest cost pathway to meet net-zero emissions reduction targets. Instead, the study examined the technologies and low-carbon fuels that gas utilities could leverage to support emissions reductions for themselves and their customers. The study then analyzed several combinations of these gas emission reduction strategies to understand their potential to contribute to net-zero emissions targets.[94]

The results show a diversity of potential pathways leveraging gas infrastructure and technologies that could support 2050 net-zero objectives. This is not intended to say that reaching these targets will be easy or that it will not require change. In this study and other work, all net-zero pathways represent transformative and uncertain changes to our energy system and the entire economy, to be implemented at an unprecedented pace. These pathways show that gas infrastructure can support such a transition, demonstrate that gas pathways should still be part of planning discussions in regions looking at net-zero targets, and support the need to avoid ruling out any options to help reach 2050 targets at this stage.

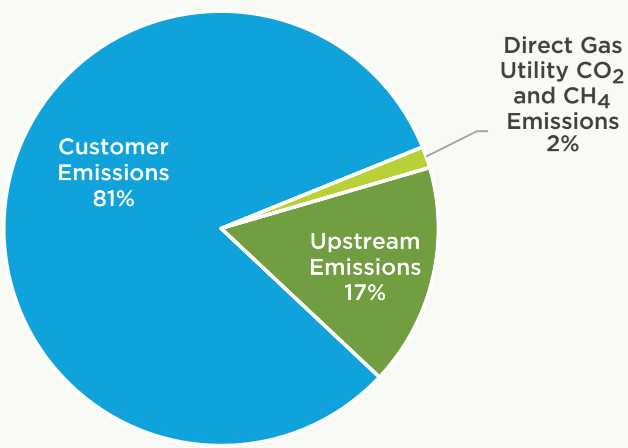
Establishing the GHG Inventory

Greenhouse gas emissions related to gas utilities can be considered in three separate categories[95]:

- **Direct natural gas utility emissions**
- **Customer emissions from the onsite combustion of gas**
- **Upstream emissions from the production and transportation of gas**

As shown in **Exhibit 11**,[96] customer emissions are the largest category. The ability of gas utilities to help their customers reduce GHG emissions will be critical to the country reaching economy-wide net-zero targets. As such, much of the focus of the analysis in this study is on pathways to reduce customer emissions, but separate opportunities and pathways are also presented for direct utility and upstream emissions categories.

Exhibit 11 – Gas Utility GHG Emissions by Category



94 Global economy-wide net-zero requirements, supported by the climate science, do not necessarily mean that all sectors of the economy will no longer have any GHG emissions. Some sectors might reach zero greenhouse gas emissions, while other sectors might have some remaining emissions that could be balanced out by ‘negative’ emissions technologies or by different sectors that are able to reach negative emissions, to achieve net-zero emissions cumulatively. For the purposes of this report, we focus on achieving net-zero emissions for customers served by gas utilities as a simplifying assumption, but targets may vary by sector and region.

95 The World Resources Institute and World Business Council for Sustainable Development (WRI/WBCSD) have established widely adopted GHG measurement and tracking protocols. These protocols separate corporate emissions for reporting companies into three categories or “Scopes.” This report avoids the scope terminology in an attempt to make the content easier to comprehend by a broad audience. However, the three gas utility GHG emissions categories discussed here do generally fall into the scope categories as well. Direct natural gas utility emissions are Scope 1 emissions. For gas utilities, customer emissions from the onsite combustion of gas sold by the company are Scope 3 emissions. Customer emissions from combustion of gas delivered but not sold by utilities are not included in Scope 3 but are sometimes included in this analysis. For gas utilities, upstream emissions from the production and transportation of gas they sell are also Scope 3 emissions. Scope 2 emissions related to electricity consumed by the gas utility are not included here but are typically negligible relative to the Scope 1 or 3 emissions, and would be mitigated as electricity generation shifts to net-zero.

96 Data from https://www.eia.gov/dnav/ng/ng_cons_sum_a_EPG0_vgt_mmcf_a.htm

Structure of this Section of the Report

The results in the remainder of this section are split into the following categories:

- **Summary of Study Approach and Pathways** – This section provides a brief overview of the different components of the analysis, what is included in the four illustrative pathways, and discusses related areas outside the scope of this analysis.
- **Customer Emission Reduction Pathways Results** – This section summarizes pathways through which gas utilities can help their customers reduce GHG emissions.
- **Gas Demand Reductions** – This section shows more detailed results of how energy efficiency, the use of gas technologies, and selective electrification[97] measures in the pathways reduce the volumes of gas required by utility customers.
- **Decarbonization of the Gas Supply** – This section shows more details on how renewable and low carbon gas supplies can help gas customers reach emission reduction targets.
- **Upstream Emission Reductions** – This section summarizes pathways to reduce upstream GHG emissions corresponding to the customer pathways.
- **Direct Gas Utility Emission Reductions** – This section summarizes pathways to reduce and offset remaining gas utility emissions directly attributable to gas utility system operations (e.g., fugitive methane emissions).

While the actions taken by customers to reduce gas demand will impact upstream and direct gas utility emissions, and the fuel supply mix dictates customer emissions, each segment was evaluated separately in this analysis. Namely, the emissions accounting is siloed, demonstrating how each category – customer, direct from gas utility, and upstream emissions – can achieve net-zero GHG emissions. For example, suppose a customer pathway calls for offsets. In that case, the offsets are not assumed to come from emissions reductions elsewhere in these listed emissions inventory categories (like upstream), to avoid accounting ambiguity.

4.1 SUMMARY OF STUDY APPROACH AND PATHWAYS

The analysis conducted in this study was designed to evaluate the potential for different combinations of emission reduction strategies (pathways) for natural gas utilities and gas utility customers to contribute to net-zero GHG emissions targets. While the pathways highlight the magnitude of the impact of different approaches toward decarbonization available to gas distribution companies, the different approaches are not optimized pathways and are intended to be illustrative of different scenarios or opportunities rather than prescriptive roadmaps for a given utility to follow. For instance, some pathways include an element of selective electrification to help inform and shape the dialog around how such measures may be able to work alongside emissions reductions in the gas system without providing recommendations on the "best" approach. Detailed region-specific and utility-specific analyses will be required to understand the optimal pathways in different states and cities. However, these national-level results suggest that climate solutions leveraging gas infrastructure should be given due consideration as part of local and national climate planning.

This section provides a brief overview of the different components of the analysis included in each of the four pathways. This section also discusses the limitations of the study scope and what sectors were included in the analysis. Additional details on this analysis and assumptions can also be found in the report appendices.

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97 Selective Electrification as a possible approach within these illustrative pathways refers to the selective use of electric appliances, equipment or vehicles that achieve consumer cost savings, greenhouse gas emissions reductions and reliability improvements relative to alternative energy options for the same applications for a given area. Selective Electrification would also be considered so to avoid or minimize adverse cost and reliability impacts to the electric grid to serve increased peak demand.

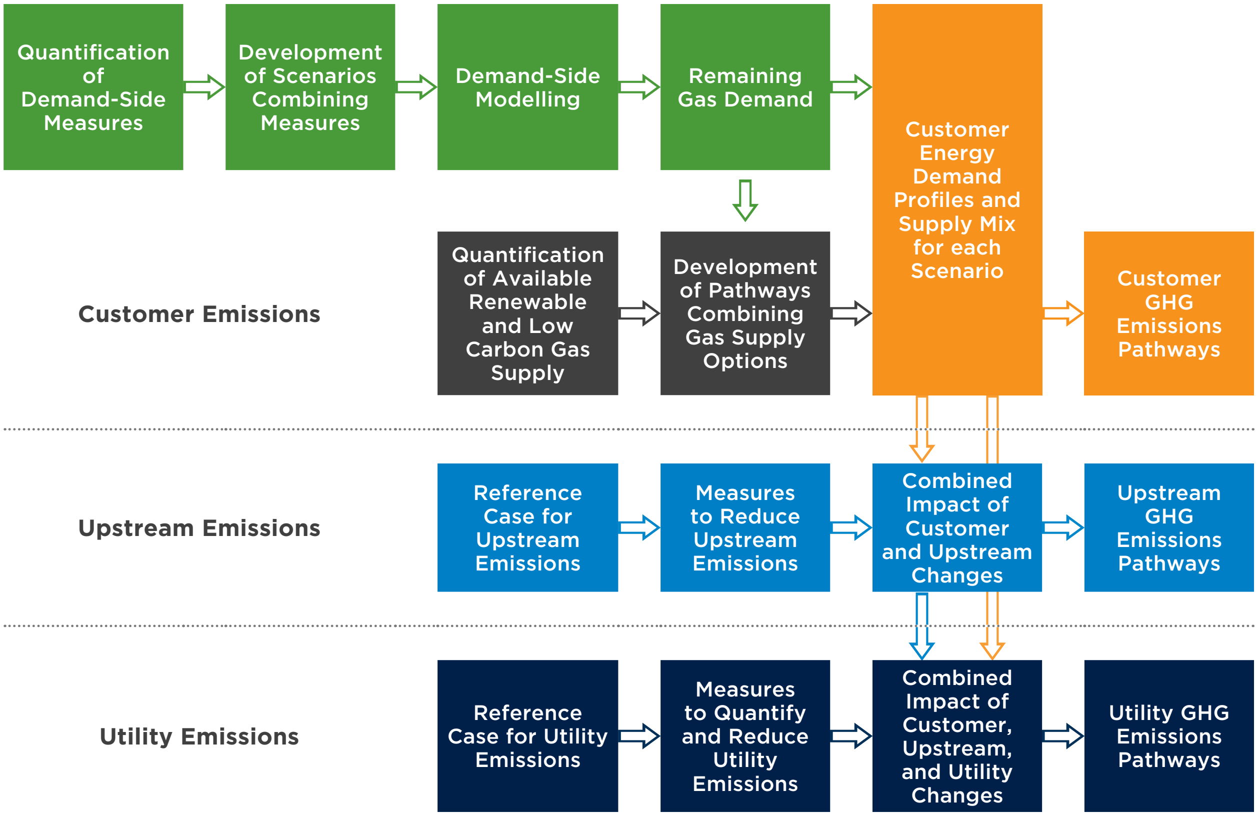
4.1.1 STUDY APPROACH

This analysis presents emissions reduction pathways for three separate categories of GHG emissions associated with the use of the gas distribution system:

- Utility customer CO_2 emissions from the consumption of natural gas
- Upstream methane and CO_2 emissions
- Gas utility methane and CO_2 emissions

As shown in **Exhibit 12**, the analysis for each of these comprises many different steps. The approach to reducing the most significant emissions component—customer emissions—is further split into three components. The first component is an analysis of illustrative scenarios for reduced gas demand by modeling different pathways combining efficiency and, in some cases, selective electrification measures (**Section 4.3**). The second component looks at the potential for renewable and low carbon gas supplies that could be used to decarbonize the remaining customer gas demand in each pathway (**Section 4.4**). The first two components were combined, along with consideration of negative emissions technologies and offsets, to develop possible scenarios for achieving net-zero gas customer GHG emission reductions (**Section 4.2**). A parallel analysis of upstream gas emissions pathways (**Section 4.5**) combines some opportunities specifically targeting upstream emissions reductions with the impacts driven by the assumptions for customer demand reductions and the changing mix of customer gas supply. Finally, the analysis includes a look at key scenarios driving utility emissions to net-zero (**Section 4.6**) through more accurate quantification of actual emissions followed by combinations of targeted emission reduction measures, in combination with impacts from the customer and upstream emissions segments.

Exhibit 12 – Overview of Study Components



4.1.2 PATHWAY DESCRIPTIONS

Four pathways combining different technologies and strategies to reduce emissions were developed to highlight a diversity of potential scenarios in which gas utilities support economy-wide net-zero emissions targets using the existing and new gas infrastructure. Each pathway increases or decreases the level of adoption for different demand- and supply-side emissions reduction measures. The pathways are illustrative of the potential impacts of different combinations and scenarios and do not represent an 'optimized' approach. The logic behind each of the four pathways is highlighted below:

- **Pathway 1: Gas Energy Efficiency Focus**

  This pathway is designed to help maintain customer fuel choice by leveraging existing infrastructure, demand-side management programs, and regulatory structures. It drives emission reductions primarily through the significant expansion of utility energy efficiency programs, promotion of gas heat pump technology, building shell retrofits, more stringent fuel-neutral building energy codes, and considerable volumes of renewable and low carbon gases.

- **Pathway 2: Hybrid Gas-Electric Heating Focus**

  This pathway focuses on coordinated gas and electric infrastructure planning and optimization through widespread adoption of hybrid gas-electric integrated heating systems, as well as selective electrification of certain end uses (with the goal of avoiding additional stress on the electric grid where possible), in conjunction with a large push for more gas energy efficiency. Greater coordination, and hybrid heating systems specifically, will require new regulatory structures to accommodate, but may also offer the potential to achieve a more optimized energy system (eg. controlling hybrid systems to respond to real-time signals like low levels of wind or solar generation).

- **Pathway 3: Mixed Technology Approach**

  This pathway represents an "all of the above" scenario with fuel-neutral policy where customers choose from a range of applications. Rather than focusing primarily on a single technology or a single energy system, this pathway illustrates a wide range of technologies to reach emission reduction targets such adoption of gas heat pumps, a ramp-up in utility efficiency programs, hybrid heating technologies, and some electric applications.

- **Pathway 4: Renewable and Low Carbon Gas Focus**

  This pathway prioritizes the decarbonization of the energy supply in order to limit the need for customers to make major changes in energy equipment and infrastructure. It relies heavily on existing and emerging renewable and low carbon fuels and less on aggressive retrofits of the building stock. This pathway still includes significant levels of gas energy efficiency improvements.

None of these pathways is based on one single technology or approach. All the pathways rely on a combination of different approaches to decarbonizing the gas system. The differences between the four pathways reflect modifications in the emphasis placed on different technologies and approaches. Additional details on some of the key assumptions included in each of the pathways are outlined in **Exhibit 13** below. A full list of measure adoption assumptions can be found in **Appendix B**.

Exhibit 13 – Examples of Changes to Customer Equipment (Demand-Side)

<table>
<tr><th>Sector</th><th>Pathway 1
Gas Energy Efficiency Focus</th><th>Pathway 2
Hybrid Gas-Electric Heating Focus</th><th>Pathway 3
Mixed Technology Approach</th><th>Pathway 4
Renewable and Low Carbon Gas Focus</th></tr>
<tr><td rowspan="2">Residential and Commercial Natural Gas Demand</td>
<td>Gas heat pump uptake for both space and water heating
• Gas heat pumps are assumed to grow to 80% of both space and water heating appliance sales for new construction by 2040, with high-efficiency furnaces for space heating for remainder of gas customers
• Gas heat pumps also used for 40% to 80% of replacements by 2040 (varies by sector)
Building envelope improvements
• Building codes shift in steps towards 'net-zero ready' homes for 50% of new construction by 2035
• 0.5% of existing buildings undergoing building shell efficiency retrofits (25-30% lower heating load) each year from 2025-2050</td>
<td>Adoption of electric ASHPs with gas backup for space heating
• 'Hybrid heating' arrangements increase to 80% of gas heating installations in new construction by 2030
• Also used for 40% to 80% of replacements by 2040 (varies by sector)
Electric heat pump water heater (HPWH) uptake
• Electric HPWHs displace natural gas equipment for 40% of new construction and replacements by 2035
Building envelope improvements
• Higher 'conventional' building codes apply for all new construction. New residential homes have 40% lower heating load by 2035</td>
<td>Gas heat pump uptake for both space and water heating
• Continuous growth of gas heat pumps for space heating covering 15% of new construction and for 20% to 30% of replacements by 2035
• Gas heat pumps for water heating covering 25% of gas unit replacements by 2040
Adoption of electric ASHPs with gas backup
• ASHPs with gas backup for space heating covering 15% of gas heating customers by 2030
Electric ASHP uptake (all electric) for space and water heating
• Electric ASHP displacement of natural gas increases, growing in new construction to 50% by 2035.
• ASHPs also used for 5% to 10% of retrofits by 2031 (varies by sector)
• Electric HPWHs displace natural gas equipment for 40% of new construction and retrofits by 2035
Building envelope improvements
• Higher 'conventional' efficiency-oriented building codes apply to all new construction by 2035</td>
<td>Gas heat pump uptake for both space and water heating
• Gas heat pumps reach 10% of appliance sales in 2031 and 15% for single-family homes in 2035
Residential & commercial customers being served with 100% hydrogen
• Hydrogen furnaces/ boilers and district energy adoption gradually increase from 0.5% in 2040 to 10% in 2050 of all new construction
Building envelope improvements
• Higher 'conventional' building codes apply for all new construction by 2035</td></tr>
<tr><td colspan="4">Other energy efficiency measures applied equally in all decarbonization pathways
• 1% of existing buildings undergoing moderate envelope improvements (5-15% heating load reduction) each year from 2025-2050
• Behavioral measures continuously increase to reach 80% of single family and 60% of multifamily existing homes in 2026 and 20% of existing commercial customers in 2023
• Smart thermostats for residential homes and building control systems for commercial buildings progressively build up to 85% of all new construction after 2035</td></tr>
<tr><td rowspan="2">Industrial Natural Gas Demand</td>
<td>• Process electrification of 2% gas demand reduction from 2050 ref. case</td>
<td>• Process electrification of 9% gas demand reduction from 2050 ref. case</td>
<td>• Process electrification of 16% gas demand reduction from 2050 ref. case</td>
<td rowspan="2">• Process electrification of 2% gas demand reduction from 2050 ref. case
• Incremental energy efficiency gas demand reduction of 15% from 2050 ref. case
• Direct use of 100% hydrogen (17% gas demand reduction from 2050 ref. case)</td></tr>
<tr><td colspan="3">• Accelerated adoption of energy efficiency measures (20% gas demand reduction from 2050 ref. case)
• Some direct use of 100% hydrogen (10% gas demand reduction from 2050 ref. case)</td></tr>
<tr><td>Transportation Natural Gas Demand</td><td colspan="4">• 413% projected gas demand growth from 2020 to 2050 (as per EIA AEO reference case)</td></tr>
</table>

4.1.3 LIMITS ON SCOPE OF THE ANALYSIS

Net-zero emissions targets represent broad and complex transformations, with many inter-dependencies between sectors. This analysis focused on the end-use sectors served by AGA's gas distribution company members, including gas utility customers in the residential, commercial, industrial, and transportation sectors. Electric power generation customers served by gas utilities were not included in the analysis. However, the analysis was completed under the assumption that net-zero requirements were economy-wide. Therefore, even sectors not explicitly analyzed here would contribute to net-zero GHG emissions by 2050. Decarbonizing these other sectors will have implications for the cost and opportunities to decarbonize the analyzed sectors. While not the focus of this study, these implications are important to recognize. The exclusion of these out-of-scope sectors from this analysis is not expected to have an impact on the validity of the study's key take-aways.

Additional details on key aspects and limitations of the study scope are discussed below:

- **Power Generation Sector**

  Gas demand in the power generation sector was not included in the reference case for demand nor considered in the decarbonized gas supply mix. This study did not include any analysis of the decarbonization of the power generation sector, but it assumes that electricity generation will be net-zero by 2050; that it will be possible to generate as much of this net-zero electricity as required by the economy; and that selective electrification of some gas end uses will effectively result in the elimination of their associated emissions. However, these assumptions are far from certain. For instance, in many states, the current generation mix is so emissions-intensive that electrification of gas end-uses can increase overall GHG emissions rather than decrease them. Moreover, greatly expanding the electricity supply while also transitioning to high levels of intermittent renewable generation is expected to come with significant challenges and costs.

  There may be untapped synergies between changes to the power sector driven by net-zero targets and technologies included in these pathways. For example, in the power sector, the National Renewable Energy Laboratory (NREL) views hydrogen as one of the most promising[98] options for long duration energy storage (beyond the daily cycling of batteries) to ensure that power is available in periods of extended lack of renewable productions (e.g., low wind speeds for a week). A developing market for green hydrogen in support of power generation, and other sectors, could facilitate the technology's adoption for pipeline blending, use in industry, and use by residential or commercial customers. Additionally, one proposed strategy for dealing with the intermittency of renewable generation is to 'overbuild' renewable capacity so that there is a higher likelihood of having enough renewables on a greater number of days of the year. A by-product of renewable capacity overbuilding would be an increasing number of days with surplus renewable electricity generation. The production of green hydrogen (discussed in **Section 3.2.2**) might be one use for such surplus power.

- **Non-utility Industrial Customers (inter-state pipelines)**

  This study did not include all industrial consumers of natural gas. The analysis focused on customers to whom utilities deliver natural gas and not industrial customers who take delivery of gas directly from inter- or intra-state pipelines (bypassing the local distribution company). This non-utility portion of industrial customers is assumed to remain roughly 50% of the total industrial gas demand, which is consistent with the AEO reference case. Non-utility gas volumes are not included in the reference case for demand or in the decarbonized gas supply mix shown in these results. Similar to the power sector, there may be synergies from these out-of-scope sectors also decarbonizing, with the largest industrial users representing some of the best candidates to adopt emerging technologies like green hydrogen and carbon capture

98 https://www.nrel.gov/news/program/2020/answer-to-energy-storage-problem-could-be-hydrogen.html

and storage, and the potential spillover benefits for the industry included in this analysis (some of which are still large industry) from the broader drive to bring those technologies to maturity.

- **Transportation Sector**

This study did not evaluate the impact of decarbonizing the transportation sector. The study pathways include the AEO's reference case for natural gas growth in the transportation sector. **Section 4.3.4** provides an illustrative pathway that medium- and heavy-duty transportation could follow on a pathway to net-zero, relying on a mix of hydrogen fuel cell and battery electric vehicles, in addition to some vehicles using gas. But the gas supply analysis here does not include those potential volumes of hydrogen, only the transportation natural gas demand that would need to be met through renewable natural gas (RNG) by 2050.

- **LNG Exports**

This study did not include any analysis of the liquified natural gas (LNG) exports, and these volumes are not included in figures showing the reference case for gas demand or the total gas supply of decarbonized gas.

- **Propane / Fuel Oil / Electric Customers**

Beyond what is factored into the AEO reference case, the analysis did not include pathways for buildings that currently rely on propane or fuel oil for space and/or water heating. Due to higher emissions and more favorable conversion economics, propane and fuel oil customers are typically the first groups of customers targeted for electrification. Significant electrification of these customers would increase the challenges on the electric grid to then also electrify natural gas customers. Though conversion to natural gas could also afford emissions reduction opportunities, it was not explored further in this study. This study also did not analyze existing all-electric customers.

- **National vs. Regional Analysis**

Parts of the analysis were conducted at the national level (transportation sector, industrial sector, upstream emissions, and utility emissions), while other aspects (residential and commercial sectors) were modelled separately for the four main census regions before the results were rolled up to national level totals presented here. Given that the pathways are not presented in terms of suggesting a single optimized approach, or even covering all the possibilities, this higher-level granularity was deemed to be sufficient.

In practice, the optimal pathways for a specific region will vary based on highly localized factors, such as climate and temperatures, energy prices, differences in the housing stock, as well as the capacity, age and GHG intensity of existing electricity generation, transmission, and distribution infrastructure, as well as the specific characteristics of the natural gas distribution system. The other decarbonization pathways adopted in a given area, including for sectors outside the scope of this work, as well as the speed of change, will also impact the optimal pathways. Evaluation of these pathways with a regional assessment of safety, affordability, reliability, resilience, and feasibility criteria will be necessary. Community and customer benefits beyond greenhouse gas emissions reductions, such as reduction in air pollution, increased economic development, and consumer energy savings, may also be realized and are not reflected in this analysis.

Exhibit 14 shows a sample of the kinds of measures and screening criteria that utilities, regulators, and policymakers could consider when developing gas emission reduction plans tailored to their region. It should be noted that thoroughly evaluating these local screening criteria requires an intensive analytical effort, and that plans will need to be re-visited periodically and evolve over time as conditions change.

Exhibit 14 – Example of Gas Utility Emissions Reduction Plan Options and Screening Criteria

Emission Reduction Options

Natural Gas Demand Reductions	Building shell upgrades (and/or code improvements focused on improving efficiency)
	High-efficiency space heating
	High-efficiency water heating
	Smart thermostats and building control upgrades
	More-efficient appliances and process equipment
	Building commissioning/ retrocommissioning
	Combined heat and power (CHP)
	District heating
	Home energy reports (behavioral efficiency)
	Low-flow hot water fixtures
	Gas heat pumps
	Electric appliances, and space and water heating equipment
	Hybrid space heating (e.g. electric heat pump paired with a gas furnace)
Renewable and Low-Carbon Gas Supply	Renewable natural gas
	Methanated hydrogen
	Hydrogen blended into gas supply
	Dedicated hydrogen infrastructure (including adoption of new end uses)
Methane Emission Reduction Measures	Differentiated gas
	Leak detection and repair programs
	More accurate emissions measurement
	Replacement of higher emitting pipe and equipment
	Operational and maintenance measures
Negative Emissions Technologies	Carbon capture and sequestration
	Direct air carbon capture
	GHG emissions offsets

→

Screening Criteria

Local Considerations	Local, state, and regional emission reduction targets and climate policy
	Regulatory environment (including cost-effectiveness tests, etc.)
	Climate (particularly heating degree days and extreme temperatures) and impact on measure efficacy
	Composition and age of existing building and appliance stock
	Commercial and industrial base
	Current and projected economic growth
	Current energy prices (gas and electricity)
	Composition and age of existing natural gas and electric utility infrastructure
	Existing/planned electricity generation, transmission, and distribution infrastructure (capacity, age, GHG intensity, etc.)
	Regional renewable resource potential
	Utility type (gas or dual fuel, investor-owned, municipal, co-op, etc.)
	Local/regional plans for non-gas decarbonization, and potential competitive impacts from surrounding regions
	System hydrogen conversion feasibility
Local Evaluation Criteria	Safety
	Costs and affordability
	Impacts to energy system (resiliency, peak demand impacts, reliability, etc.)
	Impacts to customers (energy prices, reliability, non-energy impacts, etc.)
	Customer equity
	Consumer preferences
	Feasibility and ability to scale
	Renewable and low-carbon supply considerations
	Implementation support required (traditional DSM program, market transformation effort, etc.)
	Technological readiness
	Expected future technology improvements (performance, costs, etc.)
	Current and projected natural gas utility rate base

→

Prioritized Utility Plan

Gas Utility Emissions Reduction Plan

4.2 CUSTOMER EMISSION REDUCTION PATHWAY RESULTS

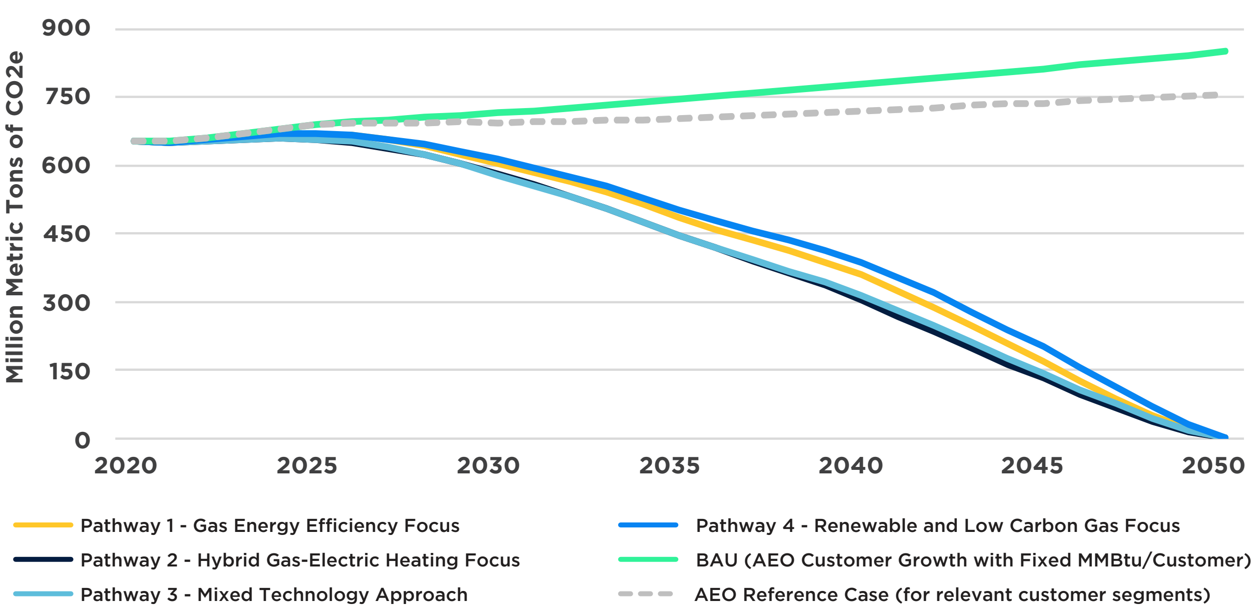
This section starts with a side-by-side comparison of the customer emission reduction pathways from the four different pathways, followed by sub-sections looking in more detail at each of the individual pathways. Later sections of this report will outline in more detail the demand-side (**Section 4.3**) and supply-side (**Section 4.4**) results that build up these customer emission reduction pathways.

4.2.1 OVERALL RESULTS

Exhibit 15 showcases the changes in GHG emissions for gas utility customers under each of the four pathways relative to the Reference Case and a 'Business-As-Usual' (BAU) Case.[99] Each of the four pathways achieves net-zero emissions by 2050, although the pattern of the emissions reductions differs modestly between pathways. The AEO Reference Case includes significant growth in natural gas customers (around 24% from 2020 to 2050 overall, but varies by sector). The energy demand associated with that growth is partially offset by energy efficiency improvement. The BAU pathway shows the same customer growth, but per-customer gas demand does not change (shows emissions without the expected reference case efficiency improvements). The four net-zero pathways include the same expectations for customer growth but leverage different combinations of efficiency, renewable and low-carbon gas supplies, and negative emissions technologies to drive emissions down.

All four of the pathways follow a relatively similar timeline and trajectory. Less emphasis was placed on optimizing all technologies included in a given pathway or trying to reach interim milestones. More emphasis was placed on developing pathways showcasing a diversity of scenarios for meeting 2050 targets. Different choices in the type and speed of actions included in the pathways would have resulted in a different emissions reduction pattern over time, although all of the pathways were designed to reach the same point by 2050.

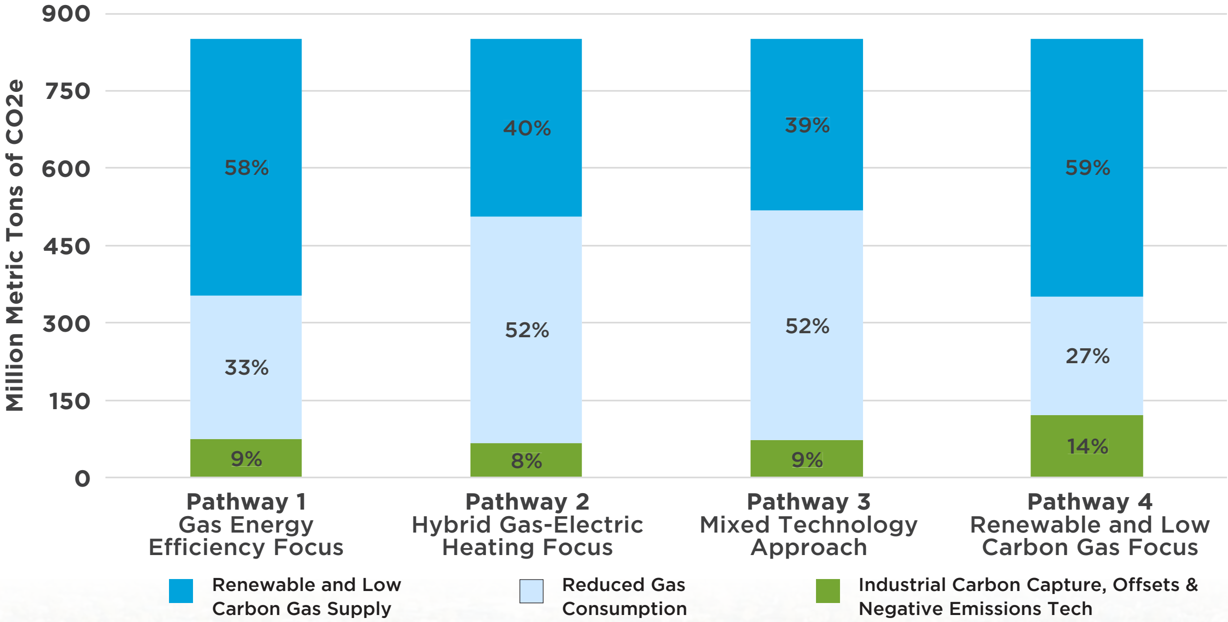
Exhibit 15 – Total Natural Gas GHG Emissions in Study Scope (Residential, Commercial, Transportation, & LDC Industrial Customers)



99 The analysis includes residential, commercial, transportation and industrial customers served by gas utilities – but not power generation customers, industrial customers purchasing gas from inter- or intra-state pipelines, or emissions from customers in these sectors that do not currently use natural gas.

To provide an overview of how the emissions reductions shown in the previous exhibit were achieved, **Exhibit 16** shows the relative contributions of different emissions reduction approaches towards 2050 net-zero emissions in each of the pathways.

Exhibit 16 – Summary of Types of 2050 Emission Reductions



More detail on the types of measures included in each of these emissions-reduction approaches and their relative contributions to 2050 targets are provided in **Table 1**. The groups of measures from this table are briefly explained below:

Table 1 – 2050 Emissions and Percentages of Total Emissions Reduction by Pathway and Measure Categories

Category / Measure	Annual Emissions (million metric tons of CO_2e)							
	Pathway 1 Gas Energy Efficiency Focus		Pathway 2 Hybrid Gas-Electric Heating Focus		Pathway 3 Mixed Technology Approach		Pathway 4 Renewable and Low Carbon Gas Focus	
2020 Natural Gas GHG Emissions	**655**		**655**		**655**		**655**	
Estimated Change Between 2020 and 2050	195		195		195		195	
Demand Reductions	**-279**	**(32.8%)**	**-439**	**(51.6%)**	**-446**	**(52.4%)**	**-230**	**(27%)**
Buildings Efficient Envelopes	-63	(7.4%)	-34	(4%)	-34	(4%)	-34	(4%)
Buildings Gas Heat Pumps	-63	(7.4%)	-		-31	(3.7%)	-14	(1.6%)
Buildings Selective Electrification	-		-71	(8.3%)	-116	(13.7%)	-	
Buildings Hybrid Gas/Electric Heating	-		-146	(17.2%)	-66	(7.7%)	-	
Buildings Dedicated Hydrogen Infrastructure	-		-		-		-6	(0.7%)
Buildings Other EE	-62	(7.2%)	-80	(9.4%)	-69	(8.1%)	-80	(9.5%)
Industrial Hydrogen Clusters	-27	(3.2%)	-27	(3.2%)	-27	(3.2%)	-48	(5.6%)
Industrial EE & Selective Electrification	-64	(7.5%)	-81	(9.5%)	-102	(12%)	-48	(5.6%)
Low Carbon Supply	**-497**	**(58.4%)**	**-344**	**(40.4%)**	**-333**	**(39.1%)**	**-500**	**(58.8%)**
Renewable Natural Gas	-284	(33.4%)	-295	(34.7%)	-201	(23.6%)	-284	(33.4%)
Methanated Hydrogen (RNG)	-173	(20.3%)	-35	(4.1%)	-104	(12.2%)	-173	(20.3%)
Hydrogen Blended into Gas Supply	-40	(4.7%)	-14	(1.7%)	-28	(3.3%)	-43	(5.1%)
Carbon Capture, Offsets and Negative Emissions Tech	**-75**	**(8.8%)**	**-68**	**(8%)**	**-72**	**(8.5%)**	**-121**	**(14.2%)**
Industrial Carbon Capture and Sequestration	-28	(3.3%)	-27	(3.2%)	-14	(1.7%)	-28	(3.2%)
Offsets and Negative Emissions Tech	-47	(5.5%)	-41	(4.8%)	-58	(6.8%)	-93	(11%)
2050 Natural Gas GHG Emissions	**0**		**0**		**0**		**0**	

- **Reductions in natural gas demand**
  - **Buildings - Envelope Efficiency:** Efficient building envelopes include building shell improvements and retrofits for existing buildings and different levels of improvement to energy building codes for new construction in both residential and commercial sectors
  - **Buildings - Gas Heat Pumps:** This category includes gas-fired heat pumps to provide space heating and cooling, and gas heat pump water heaters. Both technologies are expected to address new and existing buildings in residential and commercial sectors

- **Buildings - Selective electrification:** The selective electrification category assumes that a portion of residential and commercial consumers' use of natural gas is replaced by electricity through the adoption of air-source heat pumps (ASHPs), electric heat pump water heaters, electric cooling, electric clothes dryers, electric cooking appliances, and other electric end uses

- **Buildings - Hybrid Gas-Electric Integrated Heating Systems:** Hybrid heating category assumes adoption of a heating system that pairs an ASHP with a natural gas furnace in residential and commercial sectors

- **Buildings - Other Energy Efficiency Measures:** This category includes residential and commercial customers adoption of natural gas conventional efficiency measures such as behavioral programs, smart thermostats, energy-saving kits, ENERGY STAR appliances, high-efficiency gas furnaces, boilers, and tankless water heaters

- **Industrial - Energy Efficiency and Electrification:** Includes industrial energy efficiency improvements and selective electrification for process heating, boilers, and space heating

- **Industrial - Hydrogen Clusters:** This represents the build-out of new infrastructure to enable the development of clusters of industrial customers using 100% hydrogen

- **Buildings - Dedicated Hydrogen Infrastructure:** This category represents the build-out of new infrastructure to enable targeted residential and commercial customers to convert to 100% hydrogen use for space and water heating

- **Low carbon fuel supply**

  - **Renewable Natural Gas (RNG):** Includes methane produced by Anaerobic Digestion and Thermal Gasification from a variety of feedstocks

  - **Methanated Hydrogen:** This portion represents RNG (carbon-neutral methane that can be blended without limit in existing infrastructure) produced from a clean hydrogen feedstock and biogenic CO_2

  - **Hydrogen Blended into Gas Supply:** Hydrogen that is assumed to be mixed into existing gas infrastructure without requiring significant infrastructure and end-use upgrades

- **Carbon Capture, Offsets, and Negative Emissions Technologies**

  - **Industrial Carbon Capture and Sequestration:** This approach to reducing remaining emissions involves carbon capture and storage at industrial facilities

  - **Offsets and Negative Emissions Technologies:** This indirect approach involves buying offsets from a validated third party to fund projects that reduce the equivalent amount of remaining GHG emissions or extract CO_2 from the atmosphere through direct air carbon capture, biomass combustion with CCS, and nature-based solutions

4.2.2 PATHWAY 1 – GAS ENERGY EFFICIENCY FOCUS

Pathway 1 focuses on leveraging existing utility energy efficiency technology and DSM program infrastructure, as well as aggressive fuel-neutral building codes, to drive significant emissions reductions. This pathway also incorporates programs that support greater adoption of existing high-efficiency technologies, achieving major uptake of emerging technologies like gas heat pumps, and significantly reducing the energy used by new buildings. **Exhibit 17** shows how emissions reductions from the different measures build over time towards the 2050 net-zero target.

Exhibit 17 – Pathway to Net-Zero Customer GHGs (Gas Energy Efficiency Focus)

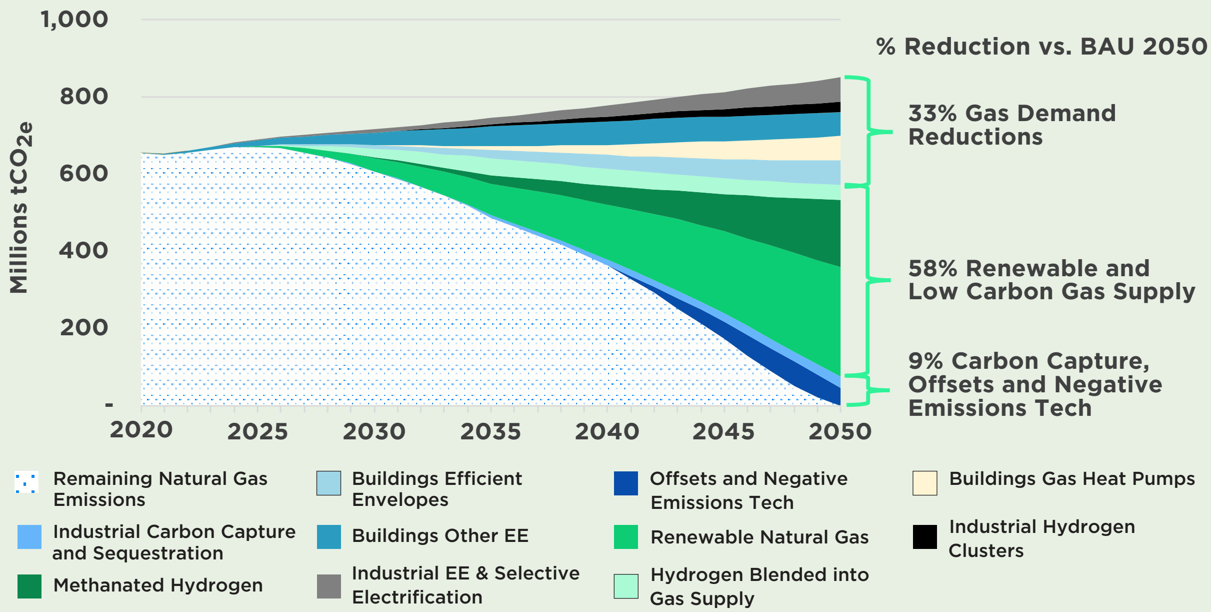
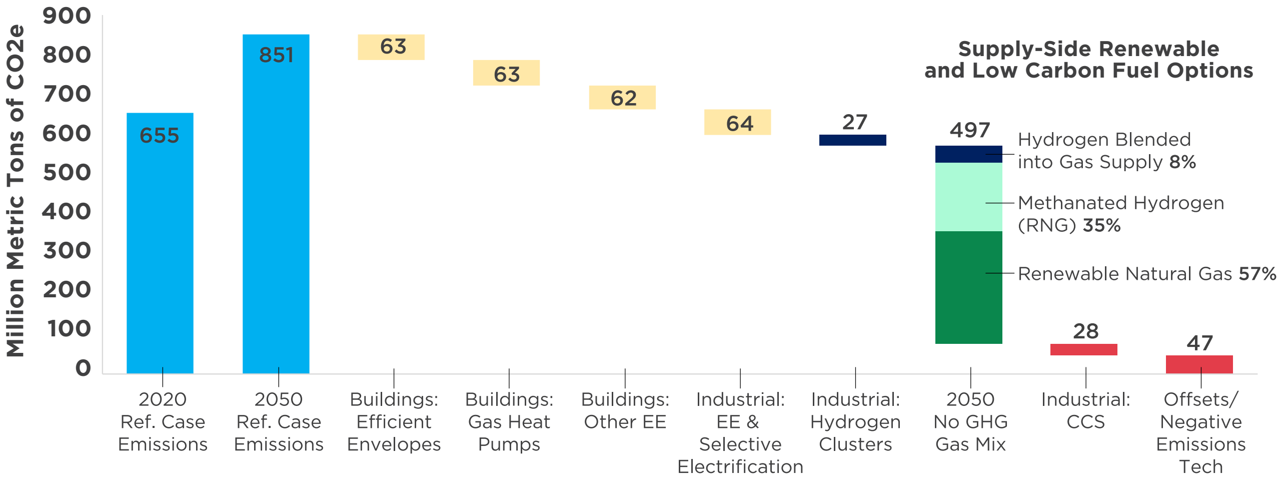


Exhibit 18 provides a more detailed snapshot of the customer emission reductions measures building up to the 2050 net-zero target for the Pathway 1. Strict energy codes for new building construction, as well as programs to retrofit existing building envelopes and drive adoption of gas heat pumps and other gas efficiency technologies, reduce 2050 gas demand in the residential sector by 23% and in the commercial sector by 11%, relative to 2020 levels, despite ~24% customer growth over that 30-year period. The mix of low-carbon gas sources used to decarbonize the remaining 2050 gas demand could be varied or optimized in different ways, but this pathway is presented with a mix of RNG, methanated hydrogen, and hydrogen blended into the pipeline system.

Exhibit 18 – 2050 Customer GHG Emissions Reductions (Gas Energy Efficiency Focus)



4.2.3 PATHWAY 2 – HYBRID GAS-ELECTRIC HEATING FOCUS

Pathway 2 focuses on using hybrid gas-electric integrated heating systems to achieve significant gas demand and emission reductions while continuing to rely on gas infrastructure to meet peak winter energy needs and minimize the electric infrastructure expansion costs. This approach is not without challenges and the need for regulatory changes, with gas utilities continuing to serve growing peak demand loads while annual sales volumes decline significantly. The pathway also includes greater adoption of gas efficiency technologies and building envelope improvements, as well as increased energy building codes. **Exhibit 19** shows how emissions reductions from the different measures build over time to reach the 2050 net-zero target.

Exhibit 19 – Pathway to Net-Zero Customer GHGs (Hybrid Gas-Electric Heating Focus)

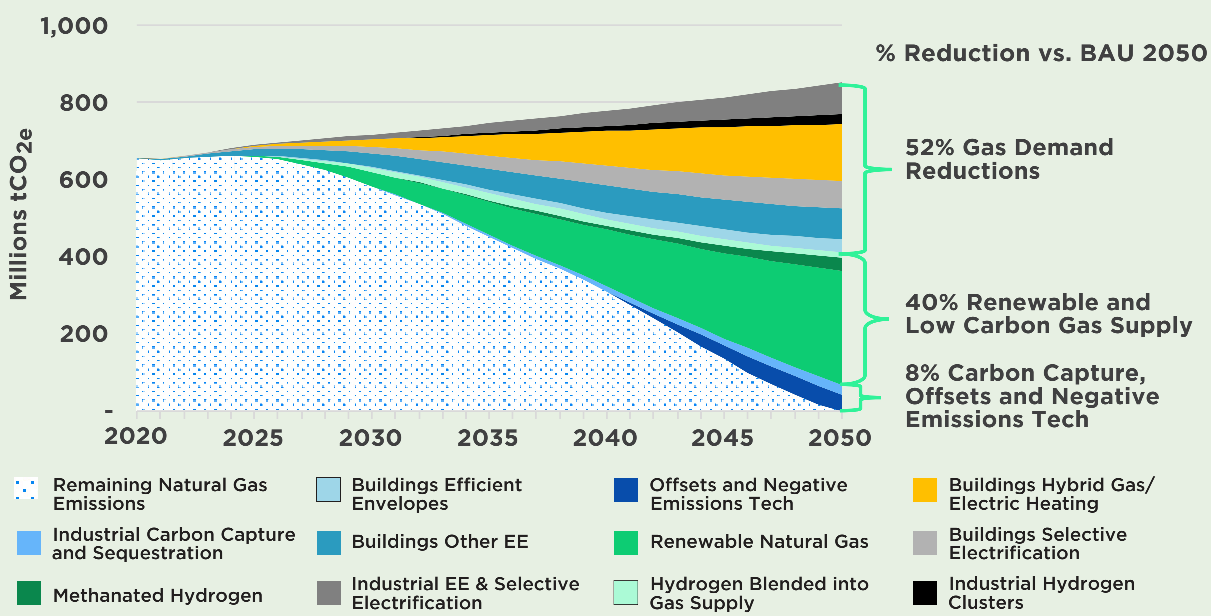
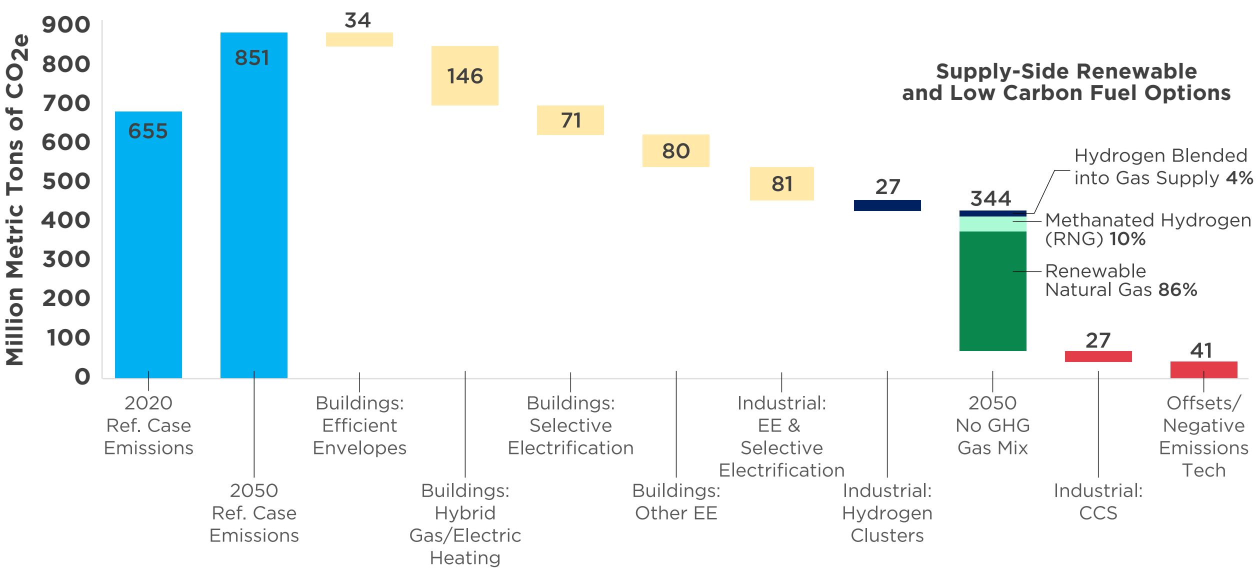


Exhibit 20 provides a more detailed snapshot of the customer emission reduction measures building up to the 2050 net-zero target. Hybrid gas/electric space heating, selective electrification of some other end-uses, as well as other energy efficiency measures, reduce 2050 gas demand in the residential sector by 54% and by 46% in the commercial sector, relative to 2020 levels, despite ~24% customer growth over that 30-year time period. The mix of renewable and low-carbon gas supplies used to decarbonize the remaining 2050 gas demand could be varied or optimized in different ways, but this pathway is presented with increased emphasis on RNG, demonstrating that a pathway exists even if hydrogen supply or use is more constrained than otherwise expected.

Exhibit 20 –
2050 Customer GHG Emissions Reductions (Hybrid Gas-Electric Heating Focus)



4.2.4 PATHWAY 3 – MIXED TECHNOLOGY APPROACH

Pathway 3 focuses on leveraging a wide range of technologies and approaches to reach emission reduction targets, reflective of the need to consider the array of emission reduction technologies available in order to increase the feasibility of reaching transformative net-zero targets by increasing consumer choices, lowering system risks, and potentially decreasing overall costs. This pathway features the adoption of energy efficiency measures, gas heat pumps, hybrid gas-electric technologies, and some electrification of building end-uses. The use of selective electrification in this pathway reflects, in part, a logic that some regions may have the electrical system capacity to support a degree of electric space heating without requiring major infrastructure upgrades in the power sector. **Exhibit 21** shows how emissions reductions from the different measures build over time towards the 2050 net-zero target.

Exhibit 21 – Pathway to Net-Zero Customer GHGs (Mixed Technology Approach)

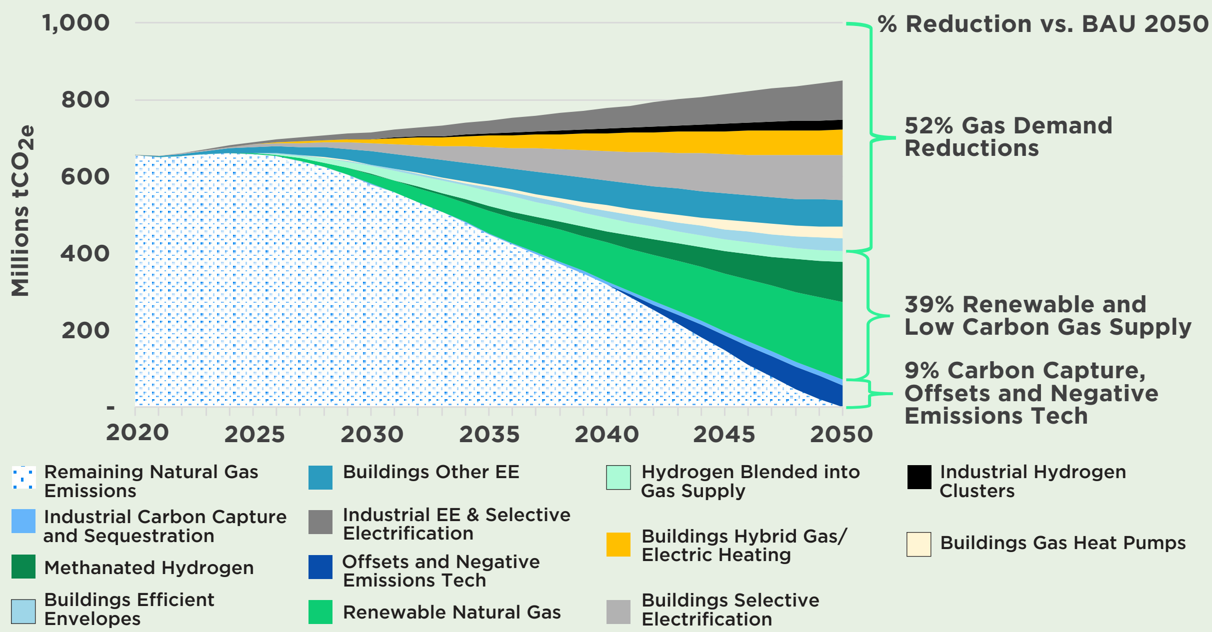
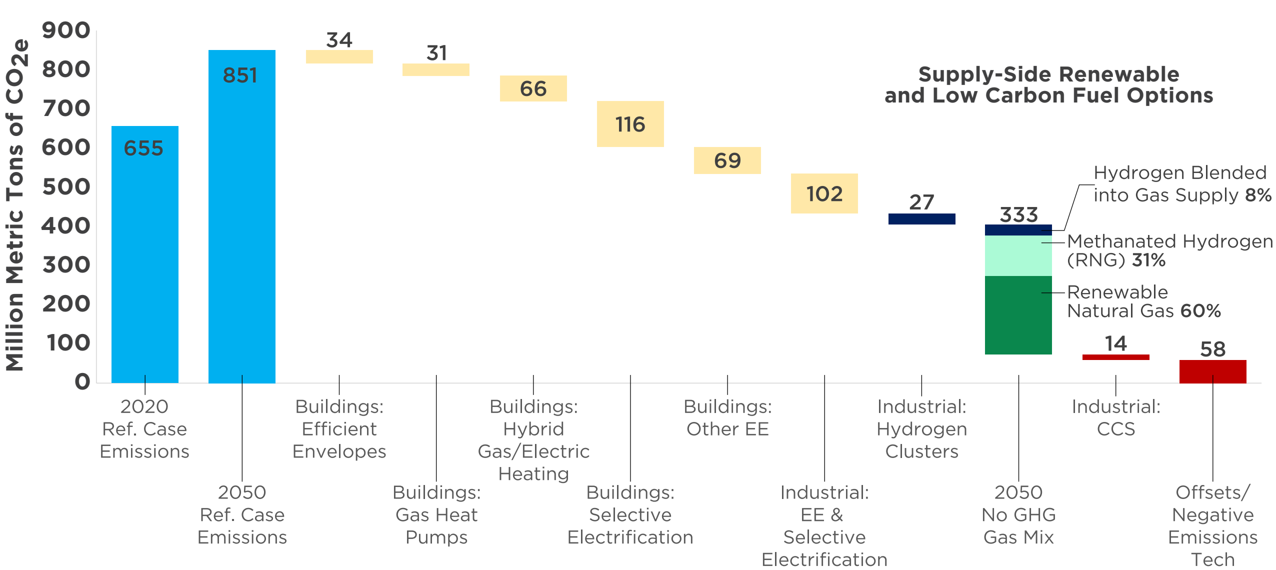


Exhibit 22 provides a more detailed snapshot of the customer emission reduction measures building up to the 2050 net-zero target. Gas efficiency upgrades, gas heat pumps, hybrid gas-electric heating, and some electrification of natural gas customers (primarily replacing new construction / part of gas customer growth) reduces 2050 gas demand in the residential sector by 52% and by 44% in the commercial sector, relative to 2020 levels. The mix of renewable and low-carbon gas supplies used to decarbonize the remaining 2050 gas demand could be varied or optimized in different ways, but this pathway is presented with a mix of RNG, methanated hydrogen, and hydrogen blended into the pipeline system.

Exhibit 22 – 2050 Customer GHG Emissions Reductions (Mixed Technology Approach)



4.2.5 PATHWAY 4 – RENEWABLE AND LOW CARBON GAS FOCUS

Pathway 4 focuses more heavily on existing and emerging renewable and low carbon fuels. This represents a pathway with less impact on consumers in that it is less reliant on consumers taking on aggressive retrofits of their homes or equipment. **Exhibit 23** shows how emissions reductions from the different measures build over time towards the 2050 net-zero target.

Exhibit 23 – Pathway to Net-Zero Customer GHGs (Renewable and Low Carbon Gas Focus)

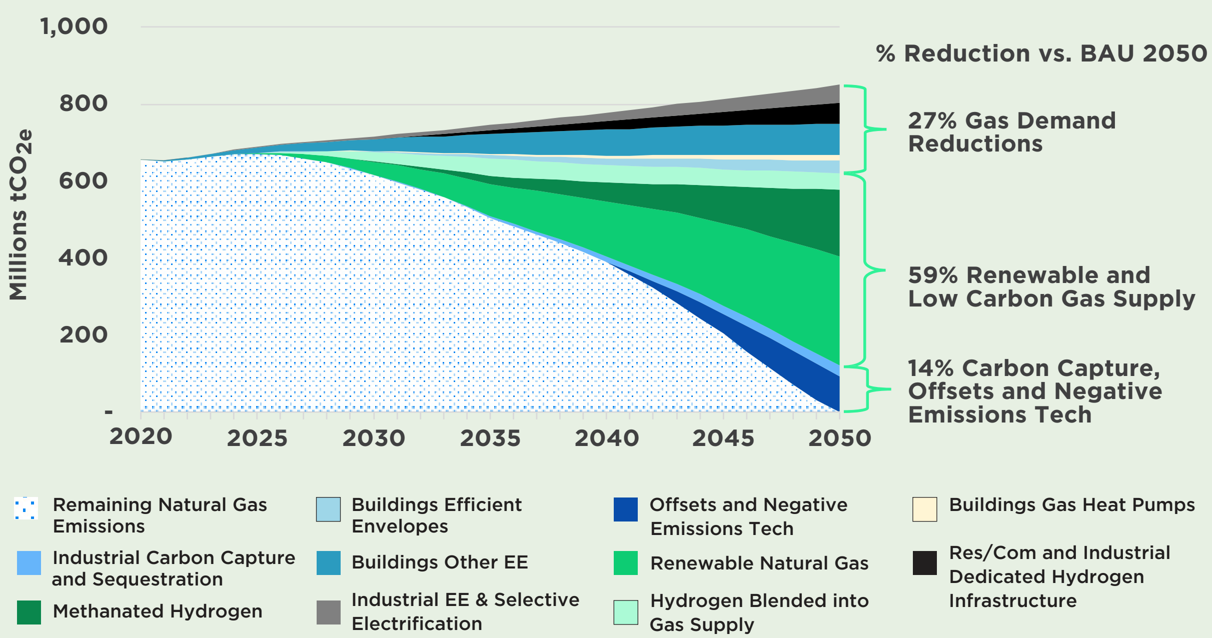
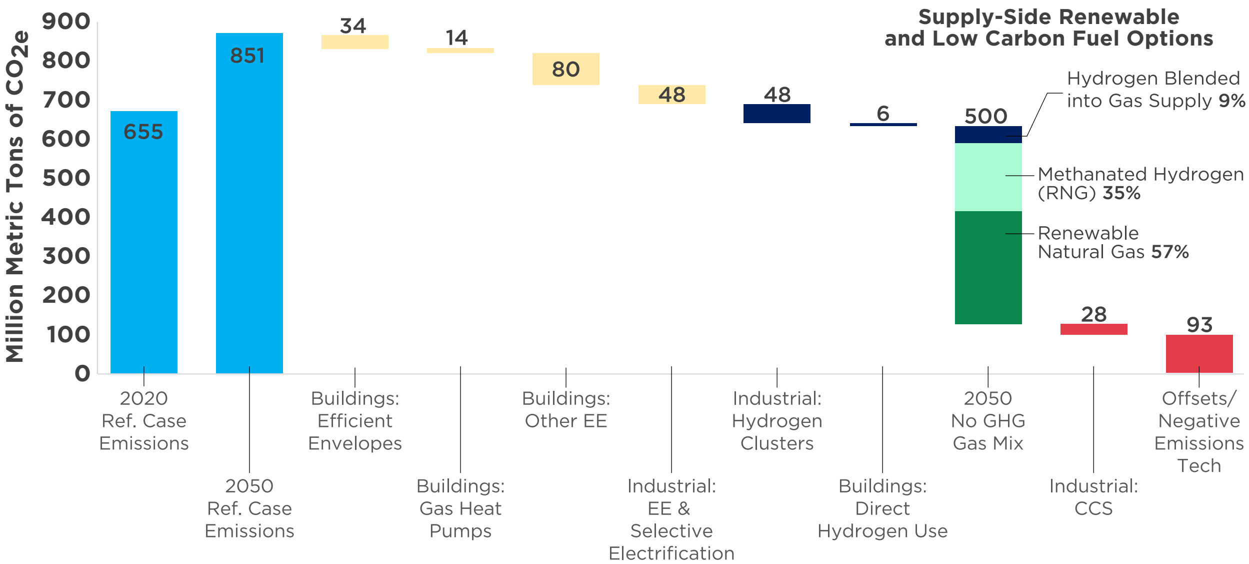


Exhibit 24 provides a more detailed snapshot of the customer emission reduction measures building up to the 2050 net-zero target. Gas efficiency and building envelope measures, moderate gas heat pump adoption, and some buildings being built or converted to 100% hydrogen use reduces 2050 gas demand in the residential sector by 9% and by 5% in the commercial sector, relative to 2020 levels (while also accounting for roughly 24% customer growth over that 30-year period). The mix of no-carbon gas supplies used to decarbonize the remaining 2050 gas demand could be varied or optimized in different ways, but this pathway is presented with a mix of RNG, methanated hydrogen, and hydrogen blended into the pipeline system.

Exhibit 24 – 2050 Customer GHG Emissions Reductions (Renewable and Low Carbon Gas Focus)



4.3 GAS DEMAND REDUCTIONS

This section starts with a side-by-side comparison of the total gas demand reduction from the four different pathways, followed by more detail on the individual sectors and measures included in the analysis.

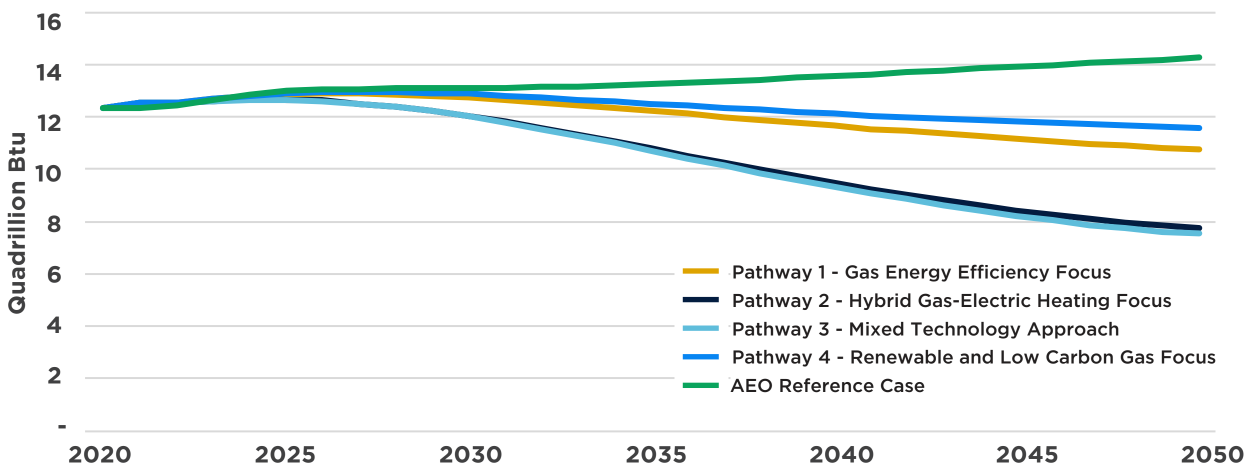
4.3.1 OVERALL GAS DEMAND RESULTS

Including all the sectors within the scope of this analysis, **Exhibit 25** shows the total gas demand changes for the four pathways studied here. These pathways are compared against a modified version of the reference case from the EIA's AEO (adjusted to include only the ~50% of industrial load assumed to be from gas utility customers).

This AEO Reference Case would see gas demand increase 16% between 2020 and 2050, while the study pathways achieve overall gas demand reductions of 6%, 13%, 37%, and 39% by 2050 compared to 2020 levels. These pathways assume the same gas customer growth levels as the AEO Reference Case (~24% residential customer growth and ~33% commercial customers growth over that 30-year time period). Thus, the gas demand reductions are even higher when compared against the projected demand in 2050 in the AEO Reference Case.

The 'Business as Usual' case is calculated using the AEO customer growth projection and assuming that gas demand by end-use remains constant over time. The demand estimation reflects that consumption by end-use varies among different Census regions and sub-sectors. In total, the approximate number of natural gas customers estimated in 2020 is 91 million, from which 88 million are residential homes (8% multifamily homes and 92% single-family homes), and 3 million are commercial customers (45% retail businesses, 23% offices, 8% institutional buildings, and 23% other businesses). The AEO customer growth between 2020 and 2050 is approximately 24% for residential and 33% for commercial.

Exhibit 25 – Total Gas Demand in Study Scope (Residential, Commercial, Transportation, & LDC Industrial Customers)



More specific values on the assumed base year and 2050 gas demand are provided for each pathway and sector in **Table 2**.

Table 2 – Total Gas Demand by Sector

	2020	Demand 2050 (Trillion Btu)				Demand variation 2020-2050 (%)			
		Pathway 1	Pathway 2	Pathway 3	Pathway 4	Pathway 1	Pathway 2	Pathway 3	Pathway 4
	Trillion Btu	Gas Energy Efficiency Focus	Hybrid Gas-Electric Heating Focus	Mixed Technology Approach	Renewable and Low Carbon Gas Focus	Gas Energy Efficiency Focus	Hybrid Gas-Electric Heating Focus	Mixed Technology Approach	Renewable and Low Carbon Gas Focus
Residential	4,969	3,838	2,283	2,410	4,511	-23%	-54%	-52%	-9%
Commercial	3,313	2,939	1,800	1,848	3,149	-11%	-46%	-44%	-5%
Industrial	3,982	3,556	3,230	2,836	3,463	-11%	-19%	-29%	-13%
Transportation	87	448	448	448	448	413%	413%	413%	413%
Total	**12,352**	**10,781**	**7,761**	**7,541**	**11,571**	**-13%**	**-37%**	**-39%**	**-6%**

The detailed results highlight that while some pathways may look similar from a total gas demand perspective, there may be significant differences between the individual components and where gas demand reductions are achieved. For example, while Pathway 3 (Mixed Technology Approach) may have had the largest overall gas demand reduction, this table highlights how this was driven in part by greater inclusion of industrial electrification options, while Pathway 2 (Hybrid Gas-Electric Heating Focus) achieved larger demand reductions in the residential and commercial sectors.

The significant gas demand reductions achieved in the residential and commercial sectors are also worth noting in context to the smaller overall percent changes in demand. The lower percentage reduction in gas demand in the industrial sector and the potential growth of natural gas use in the transportation sector, partially offsets the deeper reductions made in the building sectors.

The following sections explore additional detail in the analysis for each sector.

4.3.2 RESIDENTIAL AND COMMERCIAL SECTOR (BUILDINGS)

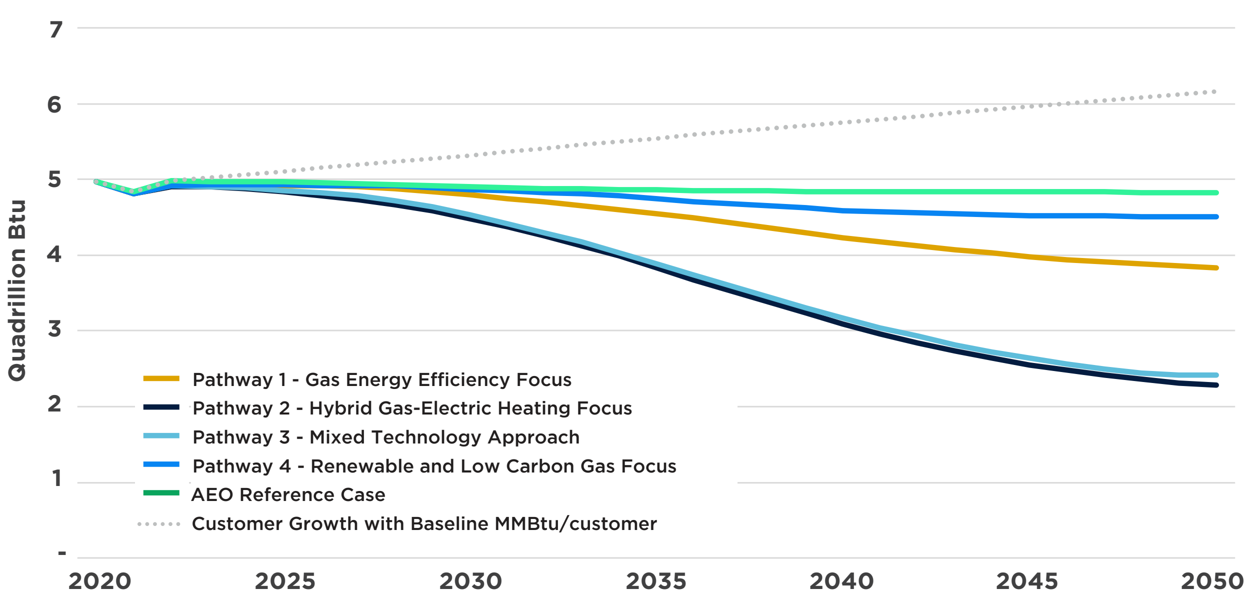
Focusing first on the residential sector, **Exhibit 26** shows gas demand changes modeled for the four pathways in this study. The AEO Reference Case for the residential sector includes a 3% demand reduction, despite the 24% customer growth over this period. This chart also includes a dotted 'Business as Usual' line showing how customer growth would increase gas demand if per customer gas consumption was unchanged (no efficiency gains or selective electrification). The large gap between the AEO Reference Case and the BAU represents expectations for significant energy efficiency improvements to be achieved by gas utility customers.

Pathway 4 features the most modest level of energy efficiency improvements and therefore shows residential gas demand that is marginally lower than the AEO reference case, reaching gas demand reduction of 9% from 2020 levels by 2050. The average per-customer gas demand reduction in Pathway 4 is approximately 27%.

Among other measures that feature higher levels of energy efficiency, Pathway 1 leverages more gas heat pumps, deeper energy efficiency retrofits of buildings, and a more stringent new construction energy code to reduce gas demand by 23% from 2020 levels by 2050.

Pathway 2 achieves a 54% demand reduction, the highest amongst these pathways, through a focus on the adoption of hybrid heating systems. Pathway 3 follows a similar trajectory, but with a broader mix of technologies - gas heat pumps, electric ASHPs, high-efficiency furnaces, hybrid heating—achieving a 54% reduction in gas demand. Reductions in residential and commercial sector gas demand tied to electrification efforts could lead to an increase in the power sector's gas demands before 2050, but that dynamic is not modeled here.

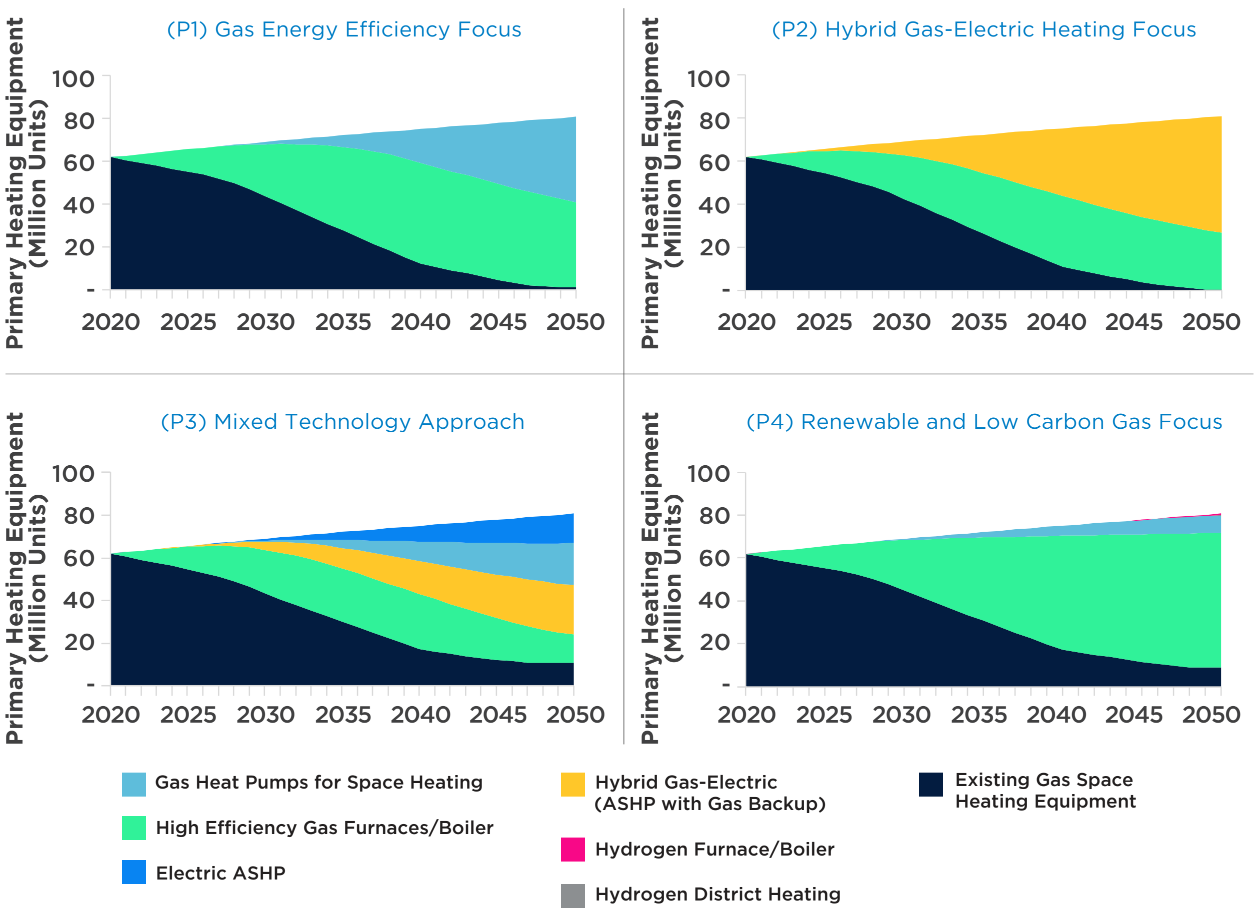
Exhibit 26 – Residential Sector Gas Demand



To give more context on some of the key changes envisioned in each pathway, **Exhibit 27** shows how the gas heating equipment stock from the AEO reference case (existing units and expected growth) is modeled as shifting over time in the different pathways. 'Existing' gas space heating equipment, which has a stock-average efficiency level of 80% in the AEO Reference Case,[100] is replaced over time by high efficiency gas furnaces, gas heat pumps, hybrid heating systems, electric ASHPs, and hydrogen furnaces and boilers. Note that the analysis only looks at how natural gas equipment from the reference case is shifted over time and does not analyze existing or reference case electric, propane, or fuel oil equipment. More details on the specific adoption assumptions for each technology included in the analysis can be found in **Appendix A**.

While the energy efficiency assumptions in most of the pathways represent a significant step-change in demand reductions from current participation levels and savings of gas DSM programs, they are not as aggressive as some other net-zero forecasts like the IEA's Net Zero by 2050 report.[101] For example, the IEA report assumes that retrofit rates will increase in advanced economies from less than 1% per year today to about 2.5% per year by 2030, whereas the retrofit rates for building shell improvements in the pathways of this analysis range from 1% to 1.5% per year. These comparatively conservative assumptions provide a buffer to help ensure that the pathways in this study are likely to be realistic and feasible. Ultimately, any opportunities to drive additional energy efficiency improvements beyond what is modeled in this analysis will make it easier for the gas customers to reduce gas demand and, consequently, support reaching net-zero targets.

Exhibit 27 – U.S. Residential Gas Space Heating Equipment Stock

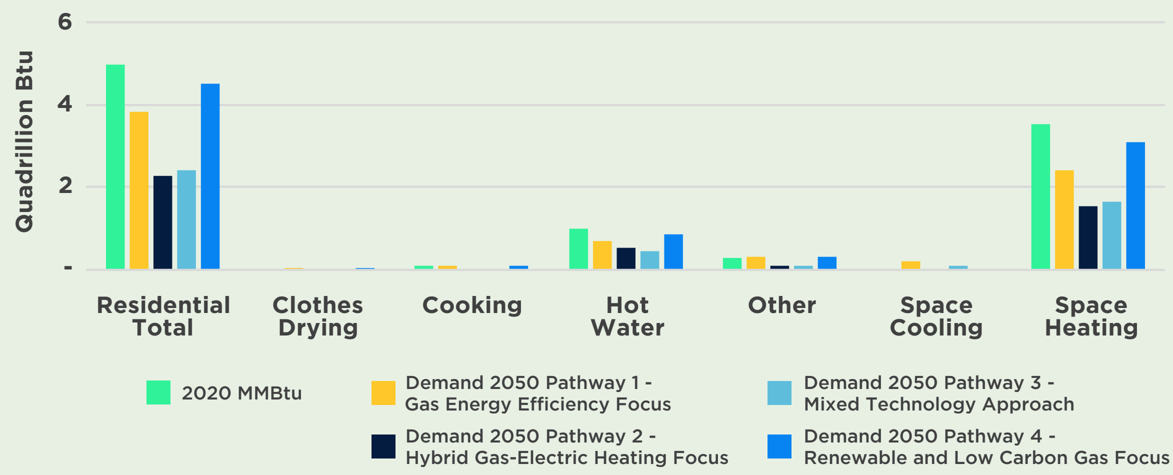


100 [Assumptions to the Annual Energy Outlook 2021: Residential Demand Module (eia.gov)](#) p. 4

101 *Net Zero by 2050: A Roadmap for the Global Energy Sector*, International Energy Agency, 2021: https://www.iea.org/reports/net-zero-by-2050

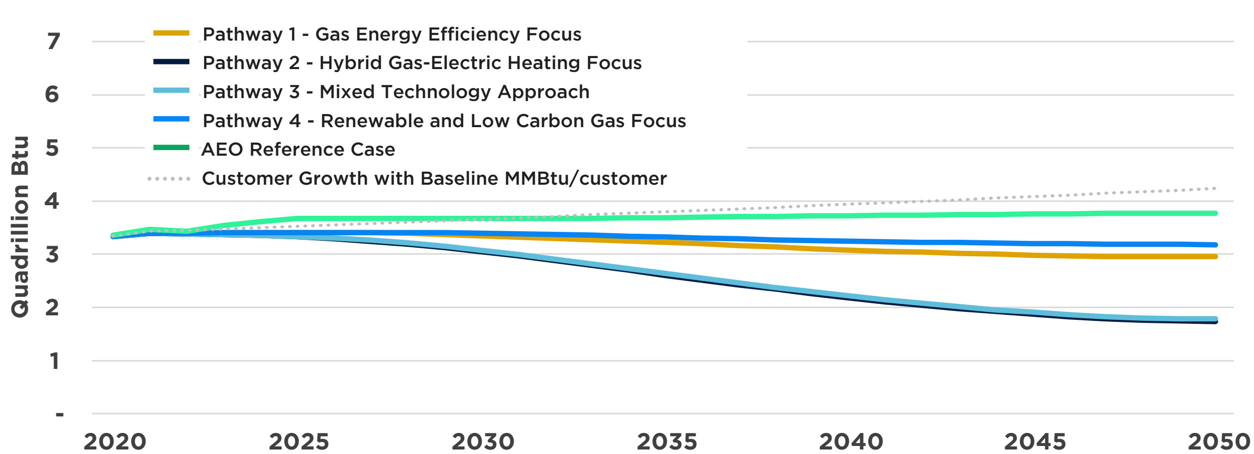
Details on the breakdown of 2050 residential sector savings by end-use are provided in **Exhibit 28**. Space heating typically dominates residential gas demand, followed by domestic hot water. Larger reductions in space heating gas demand in Pathways 2 and 3 drive the higher overall gas demand savings for those pathways. In addition to space heating, roughly half of the gas heat pumps included in this analysis are also assumed to provide space cooling, resulting in a growing demand for this end-use that was roughly zero in 2020.

Exhibit 28 – 2050 Residential Sector Gas Demand by End Use



For the commercial sector, **Exhibit 29** shows the gas demand changes modeled for the four pathways in this study. The AEO Reference Case for the commercial sector includes a 13% increase in gas demand—larger than the residential sector, but still below the 33% growth in the square footage of gas-heated commercial buildings over this period (i.e., customer growth). This chart also includes a dotted 'Business as Usual' line showing how customer growth would increase gas demand if per-customer gas consumption was unchanged (assuming no efficiency gains adopted past 2020 levels). The pathways for commercial buildings leverage similar measures to the pathways modeled for the residential sector, but in some cases with lower adoption levels.

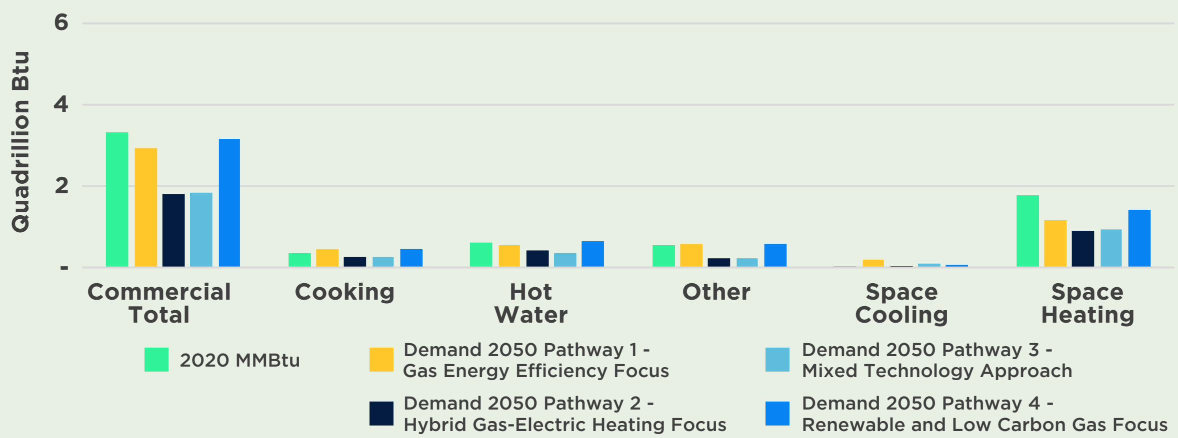
Exhibit 29 – Commercial Sector Gas Demand



Pathway 4 features the most modest levels of energy efficiency improvements and achieves commercial emission reductions of 5% from 2020 levels by 2050. Again, the average reduction in gas demand per square foot of buildings in that pathway is approximately 28%, which means the overall pathway reduction is achieved despite growth in building stock. Pathway 1 reduces commercial gas demand by 11% from 2020 levels by 2050. Pathway 2 achieves a 46% demand reduction, with Pathway 3 achieving a 44% reduction in gas demand.

Details on the breakdown of 2050 commercial sector savings by end-use are provided in **Exhibit 30**. While space heating also represents the largest gas end-use for the commercial sector, water heating, cooking, and 'other' end-uses also represent significant gas demand. The 'other' end-use for the commercial sector includes significant gas volumes for combined heat and power (CHP) systems. In Pathways 1 and 4, these CHP units would run on renewable and low carbon gases by 2050, while Pathways 2 and 3 would see gas and electric boilers replacing a portion of CHP loads by 2050, in conjunction with higher purchases of grid electricity.

Exhibit 30 – 2050 Commercial Sector Gas Demand by End-Use



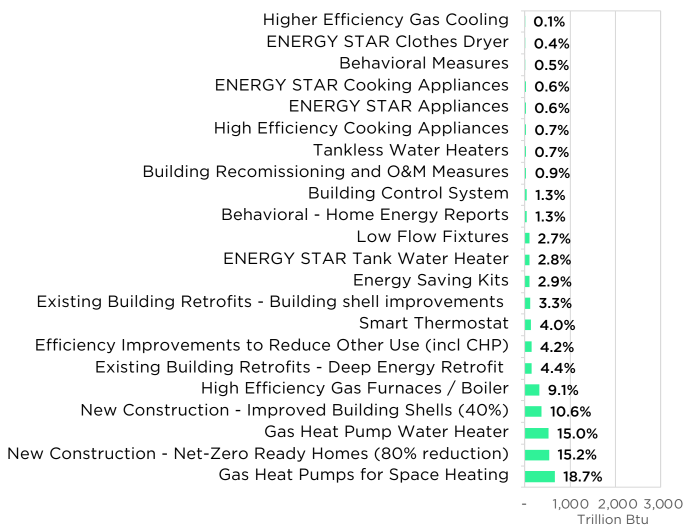
More specific values for the 2050 end-use level changes in the residential and commercial sectors are shown in **Table 3**. Additional detail on the specific measures that build up to these savings in each of the pathways is then provided below in **Exhibit 31**.

Table 3 – Summary of Gas Demand by End-Use

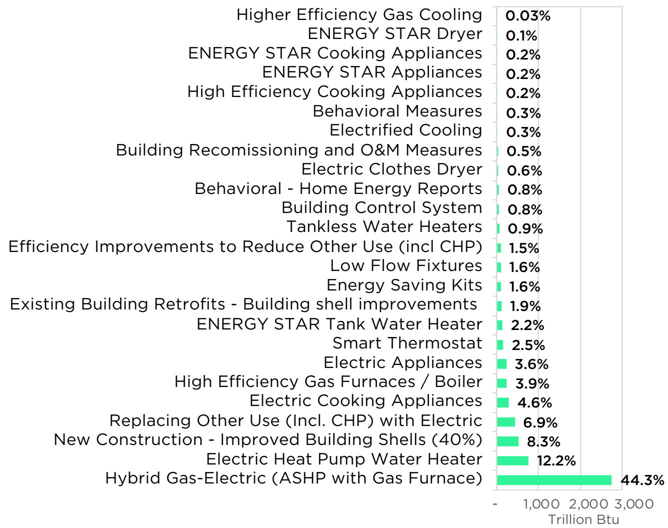
	2020		Demand 2050 (Trillion Btu)				Demand variation 2020-2050 (%)			
			Pathway 1	Pathway 2	Pathway 3	Pathway 4	Pathway 1	Pathway 2	Pathway 3	Pathway 4
	Trillion Btu	%	Gas Energy Efficiency Focus	Hybrid Gas-Electric Heating Focus	Mixed Technology Approach	Renewable and Low Carbon Gas Focus	Gas Energy Efficiency Focus	Hybrid Gas-Electric Heating Focus	Mixed Technology Approach	Renewable and Low Carbon Gas Focus
Residential	**4,969**	**100%**	**3,838**	**2,283**	**2,410**	**4,511**	**-23%**	**-54%**	**-52%**	**-9%**
Space Heating	3,527	71%	2,429	1,555	1,665	3,102	-31%	-56%	-53%	-12%
Hot Water	1,007	20%	704	552	466	872	-30%	-45%	-54%	-13%
Other	435	9%	706	176	280	537	62%	-59%	-36%	23%
Commercial	**3,313**	**100%**	**2,939**	**1,800**	**1,848**	**3,149**	**-11%**	**-46%**	**-44%**	**-5%**
Space Heating	1,773	54%	1,148	915	931	1,425	-35%	-48%	-47%	-20%
Hot Water	612	18%	558	405	364	632	-9%	-34%	-41%	3%
Cooking	344	10%	442	246	246	442	28%	-29%	-29%	28%
Other	583	18%	791	233	306	650	36%	-60%	-47%	11%
LDC Industrial Customers	**3,982**	**-**	**3,556**	**3,230**	**2,836**	**3,463**	**-11%**	**-19%**	**-29%**	**-13%**
Transportation	**87**	**-**	**448**	**448**	**448**	**448**	**413%**	**413%**	**413%**	**413%**
Total	**12,352**		**10,781**	**7,761**	**7,541**	**11,571**	**-13%**	**-37%**	**-39%**	**-6%**

Exhibit 31 – 2050 Residential and Commercial Savings by Measure

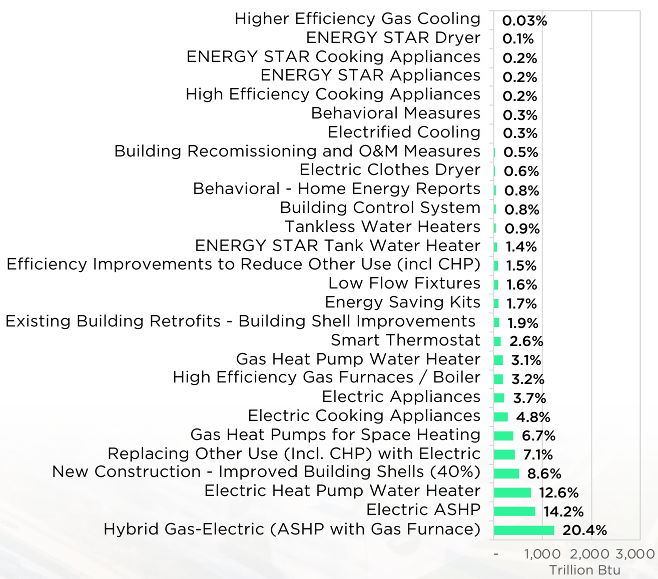
(P1) Gas Energy Efficiency Focus



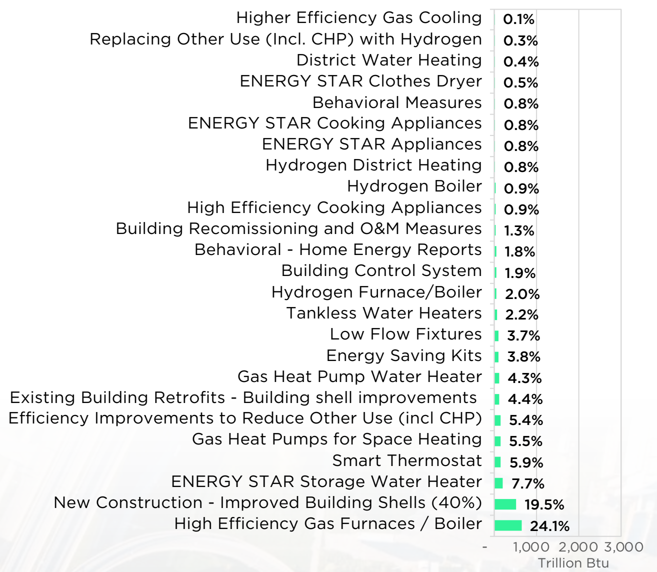
(P2) Hybrid Gas-Electric Heating Focus



(P3) Mixed Technology Approach



(P4) Renewable and Low Carbon Gas Focus

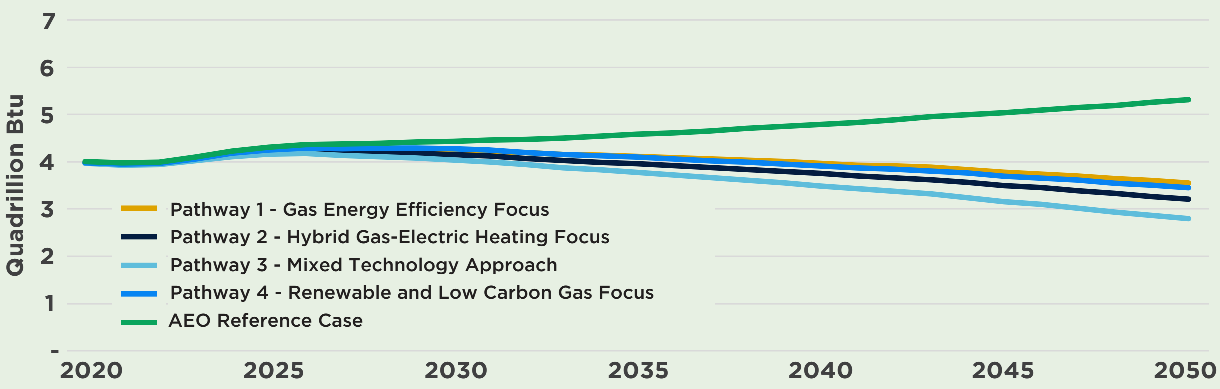


4.3.3 INDUSTRIAL SECTOR

For the industrial sector, **Exhibit 32** shows the gas demand changes modeled for the four pathways in this study. The AEO Reference Case for the industrial sector includes a 32% increase in gas demand—significantly larger than the projected growth in the residential and commercial sectors. Although only half of the U.S. economy-wide industrial gas load is included in this analysis, accounting for the portion of industry customers of gas utilities, the same growth rate is assumed here.

Significant energy efficiency improvements are assumed in all industrial pathways. Thus the industrial gas demand trends shown below for the different pathways are relatively similar. Higher levels of adoption of hydrogen clusters are assumed in Pathway 4, which leads to additional gas demand reductions relative to the other pathways. Dedicated hydrogen infrastructure adoption is shown as a reduction in pipeline gas demand within this chart.

Exhibit 32 – Industrial Gas Demand in Study Scope (Gas Utilities Industrial Customer at 50% of Total Industry)



Additional details on 2050 industrial gas demand reductions by measure type are shown in **Table 4**. For Pathways 1, 2, and 3, energy efficiency drives higher savings levels, representing 48%, 45%, and 39% of total natural gas savings, respectively. Aligned with the results from residential and commercial sectors, Pathway 3 shows higher savings from selective electrification measures than the rest of the approaches, and Pathway 4 results indicate a higher adoption of hydrogen clusters.

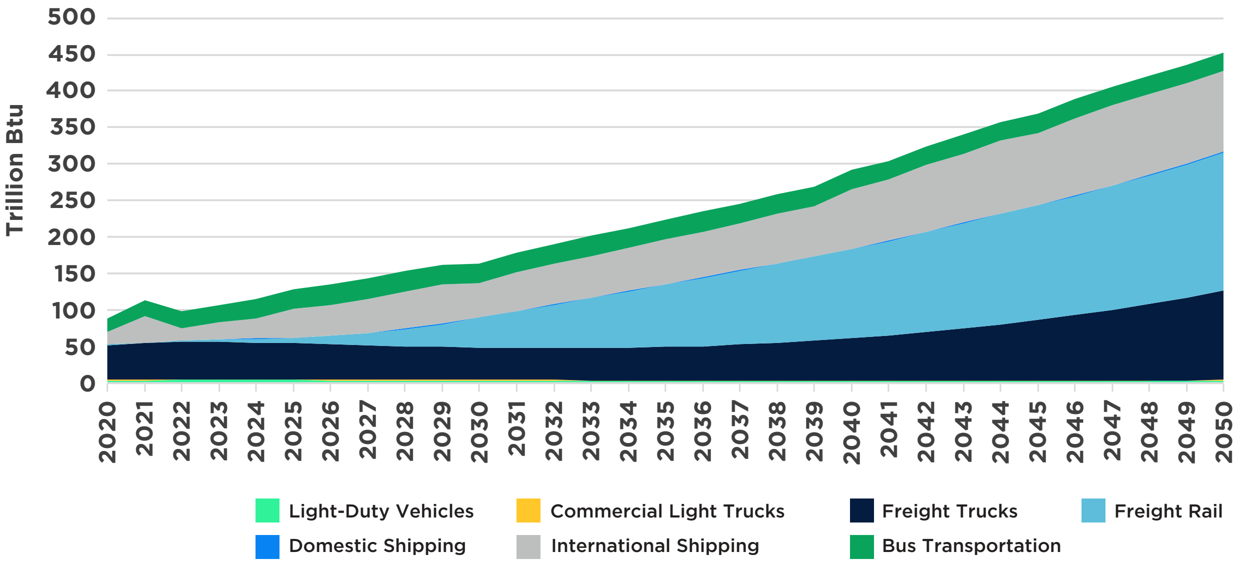
Table 4 – 2050 Industrial Sector Gas Demand Reductions by Measure Type

Measure	Trillion Btu							
	Pathway 1		Pathway 2		Pathway 3		Pathway 4	
	Gas Energy Efficiency Focus		Hybrid Gas-Electric Heating Focus		Mixed Technology Approach		Renewable and Low Carbon Gas Focus	
Selective Electrification	124	6%	471	20%	862	32%	124	5%
Dedicated Hydrogen Infrastructure	511	23%	511	22%	511	19%	906	39%
Gas Energy Efficiency	1,077	48%	1,055	45%	1,059	39%	775	33%
Carbon Capture and Sequestration	533	24%	301	13%	266	10%	519	22%
Total	**2,245**	**100%**	**2,338**	**100%**	**2,698**	**100%**	**2,324**	**100%**

4.3.4 TRANSPORTATION SECTOR

Over time, EIA projections suggest that the transportation sector will see growth in natural gas demand. Per the EIA's AEO reference case, as shown in **Exhibit 33**, transportation gas energy demand could grow fivefold by 2050. By 2050, the EIA analysis anticipates that freight transport will account for nearly 70% of transportation gas demand. The analysis in this study modeled the same total transportation gas demand included in the EIA Reference Case and specified that this gas demand be met by renewable or low-carbon gas supplies, or offsets, by 2050.

Exhibit 33 – EIA AEO 2021 Projected Transportation Sector Natural Gas Use by Mode



The transportation sector could shift significantly from the EIA's projections over time under pressure to decarbonize. There are facilitative regulatory frameworks and incentives like the federal Renewable Fuel Standard and California's Low Carbon Fuel Standard and their Zero Emission Vehicle (ZEV)[102] program, which are being mirrored in multiple states. For the transportation sector, transitioning to low/zero-emission vehicles will depend on the availability of advanced vehicle technology, requirements such as weight class and duty cycle, costs, refueling infrastructure, and consumer preference.

Electrification and low/zero-carbon fuels will likely all factor into transportation decarbonization. It is possible that geologic natural gas use for transport will increase, particularly in the short term, during a shift away from diesel and gasoline. Renewable natural gas and hydrogen will likely be incentivized for transport. In particular, transportation is a key future market for hydrogen, where the fuel could out-compete battery electric vehicles for certain ZEV applications like long-haul freight. Consequently, the natural gas sector could consequently see increased transportation reliance on their networks for natural gas, hydrogen blending, or even conversion to hydrogen.

102 ZEVs generally include battery electric vehicles and hydrogen fuel cell electric vehicles. Some programs allow for some plug-in hybrid electric vehicles to qualify.

4.4 DECARBONIZATION OF THE GAS SUPPLY

This section focuses on how the remaining gas demand can be decarbonized to support deeper customer emissions reduction pathways. The significant volumes of low- or no-GHG gas supply presented in these pathways play a major role in supporting net-zero targets by 2050.

This section describes the array of renewable and low-carbon gas supply options included in four different customer pathways—the results of which fed into the customer emissions pathways presented earlier in **Section 4.2**. Adding low-/zero-GHG supply diversity facilitates decarbonization, often without requiring consumer change.

The pathways include different combinations and approaches using geologic natural gas, renewable natural gas, and hydrogen. These are split into the following five supply options:

- **Geologic natural gas:** Gas supply from shale / conventional natural gas production
- **Renewable natural gas (RNG):** This includes methane produced by Anaerobic Digestion and Thermal Gasification from a variety of feedstocks
- **Methanated hydrogen:** This portion represents RNG (carbon-neutral methane that can be blended without limit in existing infrastructure) that was produced from a clean hydrogen feedstock and biogenic CO_2.
- **Hydrogen blending into gas supply:** Hydrogen that is assumed to be mixed into existing gas infrastructure without requiring significant infrastructure upgrades
- **Dedicated hydrogen infrastructure:** This represents the build-out of new infrastructure to enable targeted customers/clusters to convert to higher levels of hydrogen use.

Details about the supply availability of low-GHG gases are addressed later in this section, which showcases the possibilities for a significantly expanded low-GHG gas supply. Additional examination of the greenhouse gas emissions associated with the use of renewable and low-carbon gas resources is briefly described in this section and addressed in more detail in **Section 4.5** on Upstream Emissions.

4.4.1 AVAILABILITY OF RNG SUPPLIES

RNG Feedstocks

After biogas is produced through anaerobic digestion and thermal gasification of organic matter and waste, it can be cleaned and processed up to pipeline quality renewable natural gas. The variety of renewable feedstocks and production methods from which RNG can be produced are described in **Section 3.2** and illustrated here in **Table 5**.

The categories of feedstocks examined in this analysis align with categories evaluated included in the 2019 RNG Supply and Emissions Reduction Assessment that ICF conducted for the American Gas Foundation (AGF).[103]

While ICF's resource assessments apply these feedstock categories as a framework to assess RNG potential, ICF notes that these categories are not necessarily discrete and that RNG production facilities can utilize multiple feedstock and waste streams. For example, food waste is often added to anaerobic digester systems at water resource and recovery facilities to augment biomass and overall gas production. In addition, current waste streams can potentially be diverted from one feedstock category to another, such as municipal solid waste or food waste that is currently landfilled being diverted away from landfills and LFG facilities.

103 https://gasfoundation.org/2019/12/18/renewable-sources-of-natural-gas/

To avoid the potential double-counting of biomass, landfill gas (LFG) potential is derived from current waste-in-place estimates and does not include any projections of waste accumulation or the introduction of waste diversion. Such an approach likely underestimates the potential of RNG from landfill gas, but additional materials that could potentially be used to produce RNG are captured in other feedstock categories, such as municipal solid waste and food waste.

Table 5 – RNG Feedstock Types

Feedstock for RNG		Description
Anaerobic Digestion	**Animal manure**	Manure produced by livestock, including dairy cows, beef cattle, swine, sheep, goats, poultry, and horses.
	Food waste	Commercial, industrial and institutional food waste, including from food processors, grocery stores, cafeterias, and restaurants.
	Landfill gas (LFG)	The anaerobic digestion of organic waste in landfills produces a mix of gases, including methane (40–60%).
	Water resource recovery facilities (WRRF)	Wastewater consists of waste liquids and solids from household, commercial, and industrial water use; in the processing of wastewater, a sludge is produced, which serves as the feedstock for RNG.
Thermal Gasification	**Agricultural residue**	The material left in the field, orchard, vineyard, or other agricultural setting after a crop has been harvested. Inclusive of unusable portion of crop, stalks, stems, leaves, branches, and seed pods.
	Energy crops	Inclusive of perennial grasses, trees, and annual crops that can be grown to supply large volumes of uniform and consistent feedstocks for energy production.
	Forestry and forest product residue	Biomass generated from logging, forest and fire management activities, and milling. Inclusive of logging residues, forest thinnings, and mill residues. Also, materials from public forestlands, but not specially designated forests (e.g., roadless areas, national parks, wilderness areas).
	Municipal solid waste (MSW)	Refers to the non-biogenic fraction of waste that would be landfilled after diversion of other waste products (e.g., food waste or other organics), including construction and demolition debris, plastics, etc.

Available RNG Supply

In 2019, ICF completed a study of renewable natural gas supply potential for the American Gas Foundation, referred to below as 'the AGF Study.'[104] It looked out to 2040 and analyzed data on the resource availability for different RNG feedstock options to develop a 'Technical Potential' for annual RNG production in 2040, around 14,000 tBtu of combined anaerobic digestion and thermal gasification RNG supplies. The AGF Study also calculated 'High' and 'Low' cases for 2040, where projects capturing different portions of the technical potential feedstock would be developed. The 'High' and 'Low' cases considered what was achievable from the technical potential, factoring in resource competition, the timing of technology deployment, and other practical limitations. The 2019 AGF study did a high-level review of power-to-gas methanated hydrogen but did not incorporate it into the AGF Technical Potential estimate because the potential was "dependent on market developments beyond scope of study."

A lot has changed since 2019. Climate policy discussions have increasingly focused on the need for deeper reductions and more solutions to be brought to the table to reach net-zero targets. RNG markets have also continued to grow rapidly in regions like California and British Columbia, Canada—where different market mechanisms have assigned a premium value to RNG and driven the construction of projects. Some projects that would not previously have been thought to be economic have also been developed through innovations such as clustering enabling agricultural facilities together to achieve the scale required for an RNG project. There are also several promising technologies for both anaerobic digestion and thermal gasification feedstocks that could unlock more RNG supply potential.

104 American Gas Foundation, Renewable Sources of Natural Gas Supply and Emission Reduction Assessment study, 2019. https://gasfoundation.org/2019/12/18/renewable-sources-of-natural-gas/

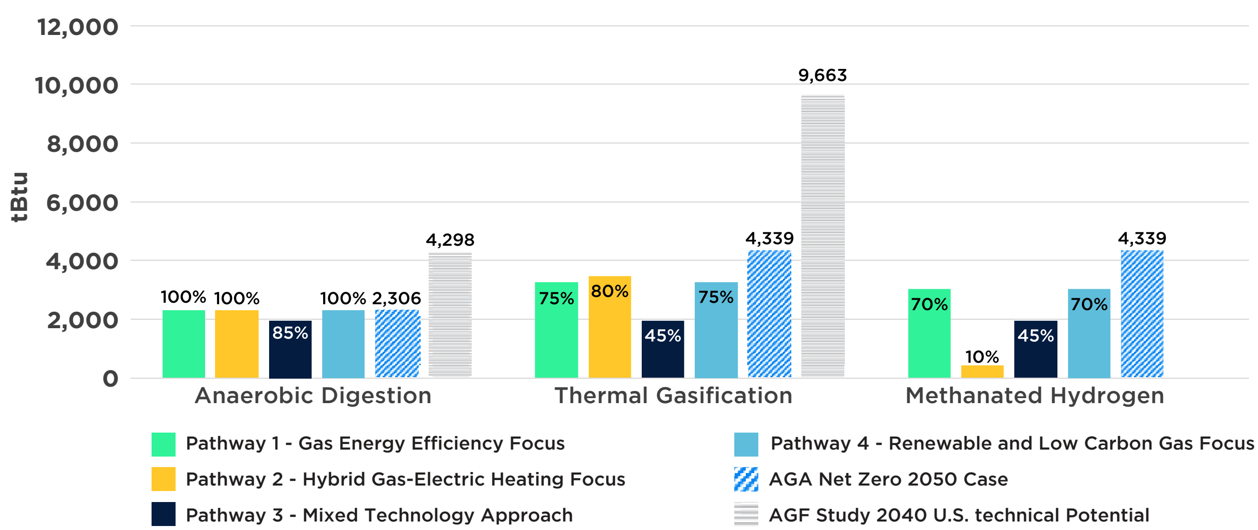
This AGA analysis was built off the same 2040 Technical Potential from the AGF Study but assumed that a larger portion of that technical potential could be captured by 2050. Higher RNG resource availability has significant implications for economy-wide decarbonization pathways. Furthermore, the greater availability of RNG enables gas utilities to provide more opportunities to fulfill net-zero greenhouse gas emissions objectives.

The RNG resource availability developed for this analysis is referred to as the 'AGA Net-zero 2050 Case.' This case represented 48% of the 2040 technical potential. In contrast, the 2040 'High Case' for the AGF Study was about 27% of the technical potential. Importantly, not all of the available AGA Net-zero 2050 Case's RNG supply was assumed to be utilized by the gas demand sectors covered in this analysis. To develop the AGA's 2050 resource potential, the levels of available resources of the eight different AD and TG feedstock categories analyzed in the AGF study were reconsidered, and the higher feasible portions of each that could be captured by 2050 are aggregated into the results in **Exhibit 34**.

To illustrate the RNG resource availability in the pathways examined in analysis relative to available RNG estimated in earlier analyses, **Exhibit 34** showcases the 2040 AGF Study Technical Potential for RNG production alongside the 2050 estimate for this study and the AGF study's 'High Case' for 2040, and the amount of low carbon gas from of each category used in the four pathways of this study. The percentages in **Exhibit 34** refer to the share of the AGA study's 2050 resource availability leveraged in each pathway. For example, Pathways 1, 2, and 4 all utilize the full amount of RNG from anaerobic digestion supplies considered available in the study's AGA Net-zero 2050 Case. This chart also showcases an expansion in the expectations for RNG production through the methanation of hydrogen; this is discussed in more detail in **Section 4.4.2** but represents another significant opportunity to develop larger renewable and low carbon gas supplies. The P2G supplies evaluated at a high level in the AGF 2019 study are captured under the methanated hydrogen umbrella in **Exhibit 34** for the AGA Net-zero 2050 Case. This is an emerging area of RNG production and not necessarily an upper limit on methanated hydrogen resources.

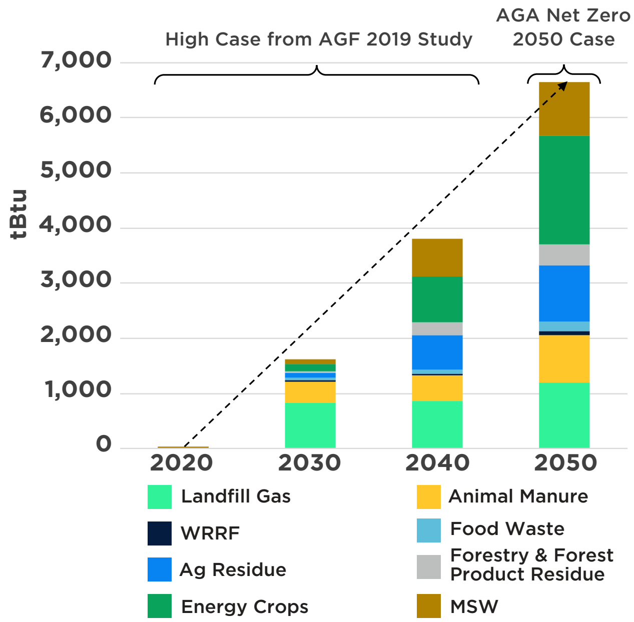
While uncertainty exists in the future production volumes of RNG developed from different feedstocks, the feedstock potential is significant. Furthermore, RNG resource development is a key area of focus for the gas utility industry to ensure that further emission reductions opportunities develop. RNG resource expansion (via improved efficiencies, easier access, and lowered costs) also represents a significant area for additional research, development, demonstration, and deployment funding to unlock low carbon energy supplies that can make a considerable difference towards reaching net-zero greenhouse gas emissions.

Exhibit 34 – Amount of RNG Supply Leveraged in Each Pathway



The potential for increased RNG resource availability is further illustrated in **Exhibit 35**. The possibility for a more significant portion of RNG supply to be developed is a critical aspect of this study and can be supported by the following rationales:

Exhibit 35 – Comparison of 2040 and 2050 Cases for RNG Supply



- This analysis (conservatively) does not assume that more feedstock becomes available. Rather, an additional decade to develop RNG projects allows for a significantly higher portion of the available resource that can be captured.
- As shown in **Exhibit 35**, the scale of RNG projects added from 2040 to 2050 is like what was projected that could come online in the previous decade.
- The AGF 'High Case' for 2040 was based on relatively conservative assumptions on the uptake of some types of RNG technologies. It did not represent an upper boundary on what might be possible.
- The climate policy landscape and targets have shifted dramatically in the last two years. Given more ambitious 2050 targets for GHG reductions, more aggressive technology adoption (RNG or otherwise) will be required and can be justified.
- Utilities that have studied RNG potential in their service territories since the AGF Study have indicated that higher levels of RNG would be capturable.
- Companies in California and other regions with markets assigning a value to RNG are bringing online projects that were not previously thought to be feasible—through innovations such as clustering—and this is unlikely to be the last innovation or improvement in this nascent market.
- While not explicitly modeled here, in the net-zero emissions 2050 envisioned in this study, electrification of light-duty vehicles will free up more biogenic sources (no gasoline being used by 2050 could mean ethanol is no longer required), which could support additional RNG production or be used for new low carbon transportation fuels.

Because the availability of RNG resources is vital for gas utility plans to support their customers in reducing emissions through RNG use, it is important for stakeholders to understand the above logic and the underlying analysis from the 2019 AGF Study. ICF is not alone in highlighting significant resource potential. For example, analysis included in the California Energy Commission's (CEC) study titled 'The Challenge of Retail Gas in California's Low-Carbon Future' gave an estimate of 4,785 BCF/year of RNG potential for the U.S., not including energy crops.[105] It should be noted that the CEC study's authors indicated their model's expectation was for much of those potential RNG feedstocks to accommodate liquid biofuels (the competition for RNG feedstocks is discussed in the next section). In a separate report by the same authors, published two months after the CEC report, they explained how their expectations for hydrogen costs had dropped dramatically from what was included in the CEC analysis, indicating how quickly technology developments can occur.[106] Their conclusion further suggests the possibility that transportation end-uses may be more likely to favor hydrogen fuel cells over biofuels.

105 https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-AP-G.pdf

106 https://www.ethree.com/wp-content/uploads/2020/07/E3_MHPS_Hydrogen-in-the-West-Report_Final_June2020.pdf

Competition for RNG with Sectors Outside the Scope of this Analysis

A consideration in the development of gas utility plans to support RNG projects to help their customers reduce GHG emissions is whether those sectors will need or want the RNG. For example, **Section 4.4** presented a high-level pathway that might be possible for the medium- and heavy-duty transportation market. That pathway saw RNG play an increasingly prominent role, but it also showed that transportation demand largely being met by electrified vehicles (which may be applicable for some MDV/HDV routes) and hydrogen fuel cell vehicles (seen as a leading option for applications where battery energy density is insufficient). Depending on future hydrogen production cost reductions, it may be more cost-effective for many transportation applications to use fuel cells over RNG. Similar uncertainty exists in the industrial sector, part of which is included in the scope of this analysis and uses a significant portion of RNG supply. Will hydrogen, carbon capture, or using carbon offsets be a more attractive option than RNG for some large industrial facilities not captured in this analysis? Will large industrial facilities competing in commoditized international markets be in a position that they can switch to RNG without losing market share to foreign competition?

Finally, in terms of the actions that should be taken in the next decade to support the development of RNG supplies, it may not matter who will be the exact customer for renewable and low carbon gas supply in 2050. Gas distribution companies are best positioned to help drive demand for RNG by supporting their customers in reducing emissions. This utility-supported adoption, coupled with an increased focus on RD&D in the area, could unlock large renewable and low carbon gas supplies that will be critical to overall 2050 net-zero targets, and are less likely to materialize without the gas industry helping drive the market forward.

GHG Emissions Accounting for RNG

Another area for consideration is the GHG intensity of RNG. **Exhibit 36** illustrates two distinct accounting methods for determining the carbon or GHG intensity of fuels. **Exhibit 36** demonstrates how RNG emissions are accounted for between the different methodologies.

For the customer emissions pathways, this analysis uses the 'combustion approach,' which focuses on the GHG emissions attributable to the combustion of natural gas at the end-use, such as in a home, business, or industrial facility. When determining the combustion GHG emissions factor, the GHG emissions attributable to the fuel use are divided by the amount of energy in the finished fuel. A combustion GHG accounting framework is the standard approach for most volumetric GHG targets, inventories, and mitigation policy frameworks (e.g., cap-and-trade programs and renewable portfolio standard (RPS) programs) as they are more closely tied to a particular jurisdiction—where the emissions physically occur.[107]

Accounting for Biogenic Emissions

IPCC guidelines state that CO_2 emissions from biogenic fuel sources (e.g., biogas- or biomass-based RNG) should not be included when accounting for emissions in combustion; only CH_4 and N_2O are included.

This is to avoid any upstream "double counting" of CO_2 emissions that occur in the agricultural or land use sectors per IPCC guidance. Other approaches exclude biogenic CO_2 in combustion as it is assumed that the CO_2 sequestered by the biomass during its lifetime offsets combustion CO_2 emissions.

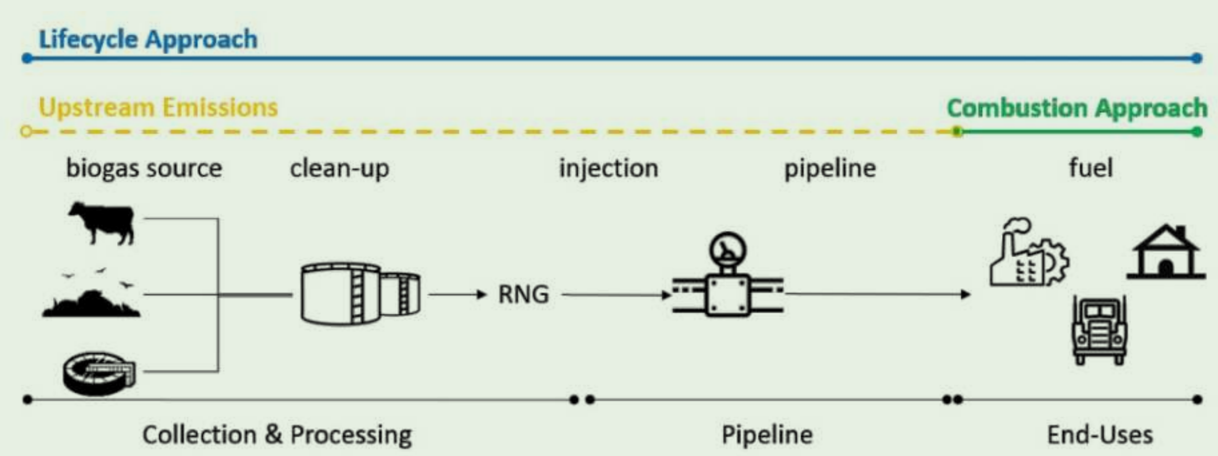
This method of excluding biogenic CO_2 is still commonly practiced for RNG users and producers. For example, LA Metro did not include CO_2 emissions in the combustion of RNG in the agency's most recent Climate Action and Adaptation Plan.

107 Estimating and attributing greenhouse gas emission reductions from RNG is inextricably linked to the type of commitment, voluntary or regulatory, and the associated GHG emission accounting approach.

Using the combustion framework, the CO_2 emissions from the combustion of biogenic renewable fuels are considered zero, or net-zero. In other words, RNG has a combustion emission carbon intensity of zero.[108] This includes RNG from any biogenic feedstock, including landfill gas, animal manure, and food waste. Upstream emissions, whether positive (electricity, etc. emissions associated with biogas processing) or negative (avoided methane emissions), are not included in the customer emissions.

ICF separated out the customer emissions into a combustion emission conversation to facilitate a conversation about gas end-use. This report aimed to demonstrate the complete picture of gas utility-related emissions, so the direct and upstream emissions are also discussed, as categorized in the emissions inventory in **Exhibit 11**. Thus, in addition to the carbon-neutral combustion of RNG by utility customers, upstream emissions from RNG (positive and negative) are analyzed as part of the upstream emissions analysis in **Section 4.5**.

Exhibit 36 – RNG Upstream Emissions and Combustion Approach for Customer Emissions



108 Excluding RNG from the non-biogenic fraction of MSW. Consistent with the ICF assessment of RNG conducted for the American Gas Foundation (AGF) in 2019, non-biogenic MSW is included in the RNG resource potential for this analysis. In most cases, the thermal gasification of the non-biogenic fraction of MSW yields lower CO_2e emissions than geologic natural gas. In the same AGF study, ICF developed an estimated emissions factor of 15 kg/MMBtu for renewable gas from thermal gasification of non-biogenic MSW, which is incorporated in this analysis.

4.4.2 AVAILABILITY OF HYDROGEN SUPPLIES

This study assumes a mix of gray, blue, and green hydrogen for initial consumption of the fuel, with a transition over the study period to lower-emitting sources, resulting in 75% green and 25% blue hydrogen by 2050. For the purposes of customer emissions, all hydrogen is treated as zero-emissions fuel use. The upstream emissions analysis (**Section 4.5**) includes upstream emissions from the different production sources, with the decreasing upstream emissions factor over time as the supply shifts to clean hydrogen.

For RNG, the key limiting factors on available supply are expected to be the total RNG feedstock potential, competing uses for RNG across sectors, as well as the RNG supply costs. But hydrogen is a little different, with more constraints on the ability of gas customers to acquire and use hydrogen, not on the hydrogen supply that could potentially be available. Hydrogen production is generally limited only by the expansion of renewable or nuclear electricity generation, and reforming methane coupled with carbon capture. To illustrate, as part of the H2@Scale project, NREL conducted a 'Resource Assessment for Hydrogen Production' and found that potential hydrogen needs would only require a relatively small percentage of the technical potential for renewable generation in the United States.[109] While the technical potential likely includes many challenging-to-develop projects, as discussed in **Section 4.1.3**, there are also discussions of strategies that would 'overbuild' renewable generation capacity and may be synergistic to large-scale hydrogen production.

Further, forecasted hydrogen prices have been decreasing significantly. The Hydrogen Insights report published by the Hydrogen Council and McKinsey & Company in early 2021 noted that green hydrogen costs are declining faster than previously expected such that it could reach cost parity with gray hydrogen before 2030 in some cases, largely due to declining renewable electricity costs. In the last year, the Hydrogen Council's projections of renewable costs for 2030 dropped by as much as 15%. Anticipated electrolyzer capital cost reductions by 2030 (which are also accelerating at 30-50% lower than projected in the Council's 2020 report) will also reduce the price of green hydrogen.[110] Through its Energy Earthshots Initiative, the Department of Energy aims to reduce the cost of green hydrogen to $1/kg by 2030.[111] This facilitative initiative establishes funding and guidance to accelerate the drop in hydrogen prices further. If successful, it could dramatically transform the industry. Though green hydrogen production is dependent on water resources and gray hydrogen uses natural gas resources, potential hydrogen production is overarchingly an issue of economic feasibility and not an issue of resource supply.

In another study for the H2@Scale project, in place of hydrogen production limits, NREL focused on limitations on how hydrogen could be used—assuming that with current gas infrastructure up to 20% hydrogen (by volume) could be blended into the U.S. natural gas pipeline system.[112]

This analysis takes a similar approach, assuming the limitations on hydrogen use are a function of constraints on customers' ability to acquire and use hydrogen, not in the production of hydrogen. The pathways considered here for the deployment of hydrogen are outlined in **Exhibit 37** and described below.

109 https://www.nrel.gov/docs/fy20osti/77198.pdf

110 Hydrogen Council, McKinsey & Company, 2021. Hydrogen Insights, https://hydrogencouncil.com/en/hydrogen-insights-2021/

111 U.S. Department of Energy, 2021. https://www.energy.gov/articles/secretary-granholm-launches-energy-earthshots-initiative-accelerate-breakthroughs-toward

112 https://www.nrel.gov/docs/fy21osti/77610.pdf

Exhibit 37 – Hydrogen Deployment Pathways

1. H2 Blended into NG Supply
2. H2 Methanated into Synthetic NG & Blended into NG Supply
3. H2 Clusters for Industry & Power Generation
4. New Customers in Targeted Regions Built for 100% H2
5. Targeted Conversion of Existing Customers to 100% H2
6. Any Other Approaches

   E.g., H2 powering distributed fuel cells

Hydrogen Deployment

- **Hydrogen Blended into the Gas Supply:** The 20% by volume (closer to 7% on an energy basis) level is commonly discussed as an upper blending limit without requiring significant upgrades to customer equipment or the gas distribution system. Existing transmission pipelines are considered to have a higher tolerance limit, of up to 50% by volume.[113] This is an area of significant research and testing for AGA members to validate the levels possible with and without equipment upgrades and understand what changes might be required to achieve higher blending levels. All the pathways in this study allow up to 20% hydrogen blending by volume (but not all pathways go up to the full 20%).

- **Hydrogen Methanated into Synthetic RNG and Blended into the Natural Gas Supply:** Without exceeding a 20% hydrogen blend by volume or building new hydrogen infrastructure, one option for customers to take advantage of even more low/no-carbon hydrogen supplies is by transforming that hydrogen into a synthetic form of renewable methane. Adding the clean hydrogen to a biogenic CO_2 supply in a methanation process can produce a synthetic renewable natural gas that avoids the need for customer equipment or infrastructure changes. The limitation on this pathway is the availability of biogenic sources of CO_2, which ensures the resulting synthetic natural gas is carbon neutral.

  Methanation is a commercially available process, and various sources of biogenic CO_2 might be available. The potential here is quantified based on an assumption that the RNG thermal gasification processes are paired with green hydrogen, thus taking advantage of biogenic CO_2 coming off that process and in effect doubling the RNG produced by thermal gasification. By some estimates, increasing yields by more than the doubling assumed here could be possible, but even this level of hydrogen methanation yields a very large source of renewable and low carbon gases to decarbonize customer demand. The exact yield varies as it depends on multiple process variables: the composition of syngas being used, which is in turn a function of feedstock composition, operating temperature, air mix vs. pure oxygen flow, and gasifier type, among other factors.

113 Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues (nrel.gov)

- **Hydrogen Clusters for Industry and Power Generation:** Hydrogen has some advantages that make it particularly attractive for certain industrial sectors with high-temperature heating requirements and long-duration storage applications for power generation. Clean hydrogen could also meet lower temperature space, water, and process heating needs if economics were favorable (e.g., if aggressive hydrogen price reduction forecasts materialize, especially for equipment where electric efficiency not greater than 100%). One approach being considered is developing clusters or hubs grouping facilities looking to use 100% hydrogen to facilitate better the deployment of new hydrogen infrastructure. Grouping large energy consumers into clusters serves more load with less new infrastructure. The results show this opportunity under the 'dedicated hydrogen infrastructure category' for all four pathways, and more details on specific industrial assumptions were included in **Section 4.3.3**.

- **New Buildings in Targeted Regions Built for 100% Hydrogen:** One approach to leverage hydrogen beyond the 20% blending limits would be to shift some end-uses to dedicated hydrogen infrastructure and equipment. This might require sections of existing gas distribution system to run on 100% hydrogen or building out new segments with hydrogen-specific infrastructure. Demonstration projects in Europe are already showing how different appliances for homes can run on hydrogen, and neighborhood scale demonstrations are planned. While residential and commercial customers are unlikely to be 'anchor tenants' initially, meaning these customer support in initial buildout of dedicated hydrogen infrastructure, there may be opportunities in some regions, potentially adjacent to industrial hydrogen clusters for example. Such conversions will also be easier for new construction—where buildings/neighborhoods can be designed for hydrogen from the start, potentially even with hydrogen power a district heating loop. This opportunity was included only for Pathway 4 in the analysis, with the first buildings come online in 2040—but this would be an opportunity that continues to grow beyond 2050. The results show this opportunity under the 'dedicated hydrogen infrastructure category,' and more details on specific assumptions were included in **Section 4.3**.

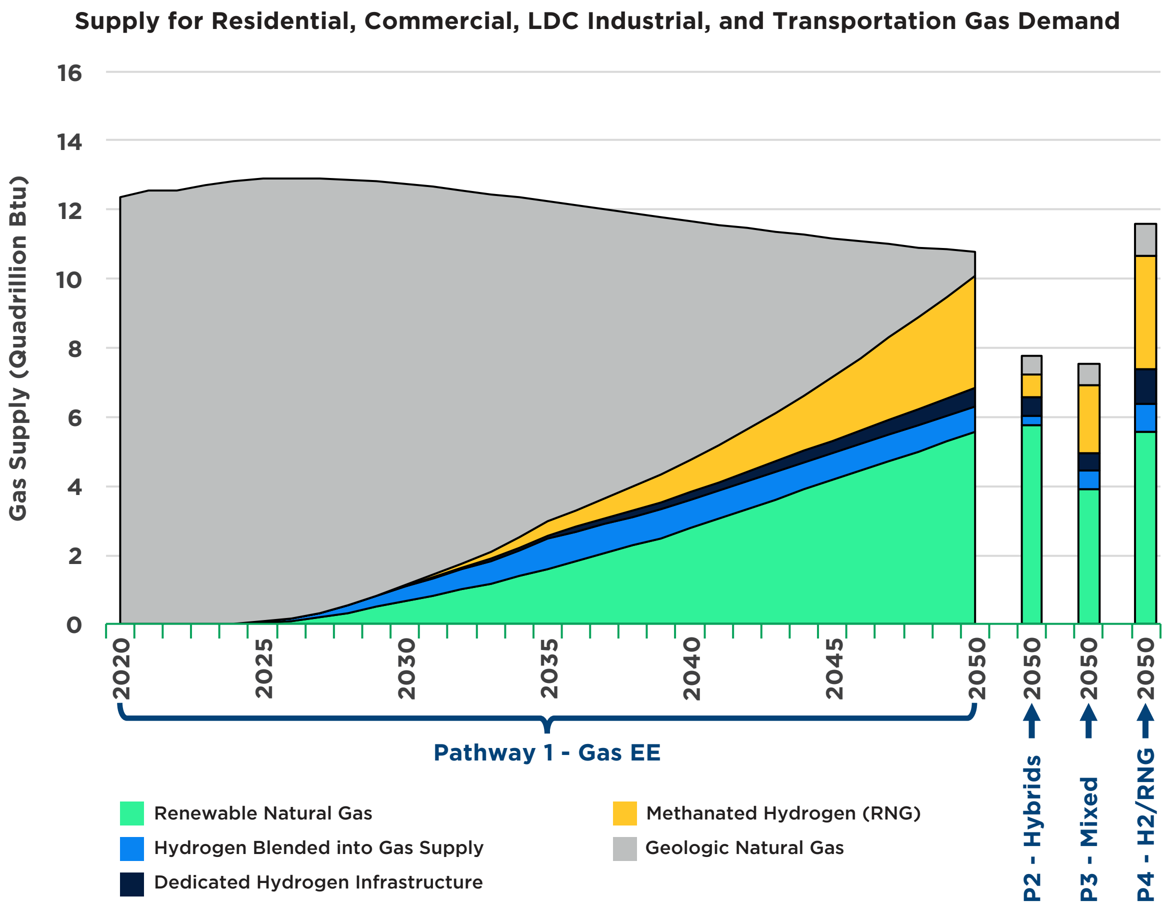
- **Targeted Conversion of Existing Buildings to 100% Hydrogen:** This approach would involve the conversion of existing buildings to 100% hydrogen. Hydrogen-compatible equipment is increasingly available for end-uses ranging from residential boilers to commercial CHP units. Equipment could be replaced over time in anticipation of a later switchover point. This opportunity was included only for Pathway 4 in the analysis, with the first buildings come online in 2045—but this would be an opportunity that continues to grow beyond 2050. The results show this opportunity under the 'dedicated hydrogen infrastructure category.' More details on specific assumptions were included in **Section 4.3**.

- **Other Approaches to Hydrogen Deployment:** There are numerous other pathways to utilize hydrogen for current gas customers. One approach would be whether existing distribution systems and customer equipment could handle higher than 20% blends, something being studied by gas utilities. Another would be the use of distributed hydrogen fuel cells to support localized electric demand in a highly electrified future (assumes many customers would be electrified, causing constraints on the electric distribution system, which could be alleviated with localized power generation from fuel cells supplied with hydrogen through existing gas distribution infrastructure). These and other potential pathways were not analyzed in this study.

4.4.3 GAS SUPPLY PATHWAYS

The combined results of the demand-side analysis and the assumed changes to the gas supply mix for each pathway are showcased in **Exhibit 38**. The reduction in the total height of the chart over time showcases how gas demand is expected to reduce by 2050 for a given pathway. The bands within the chart then show how the mix of remaining gas supply changes out to 2050 for the customer groups included in the scope of this analysis (thus not including power generation, roughly half of industrial customers, or LNG exports). Geologic gas use is significantly reduced in all the pathways, with different degrees of RNG and hydrogen options providing the renewable and low carbon gas supply in each pathway. The main portion of **Exhibit 38** showcases how the supply phases in over time for Pathway 1 (Gas Energy Efficiency Focus), while the bars to the right contrast the 2050 results for the other three pathways. The full approaches for the other pathways can be seen in **Exhibit 39**.

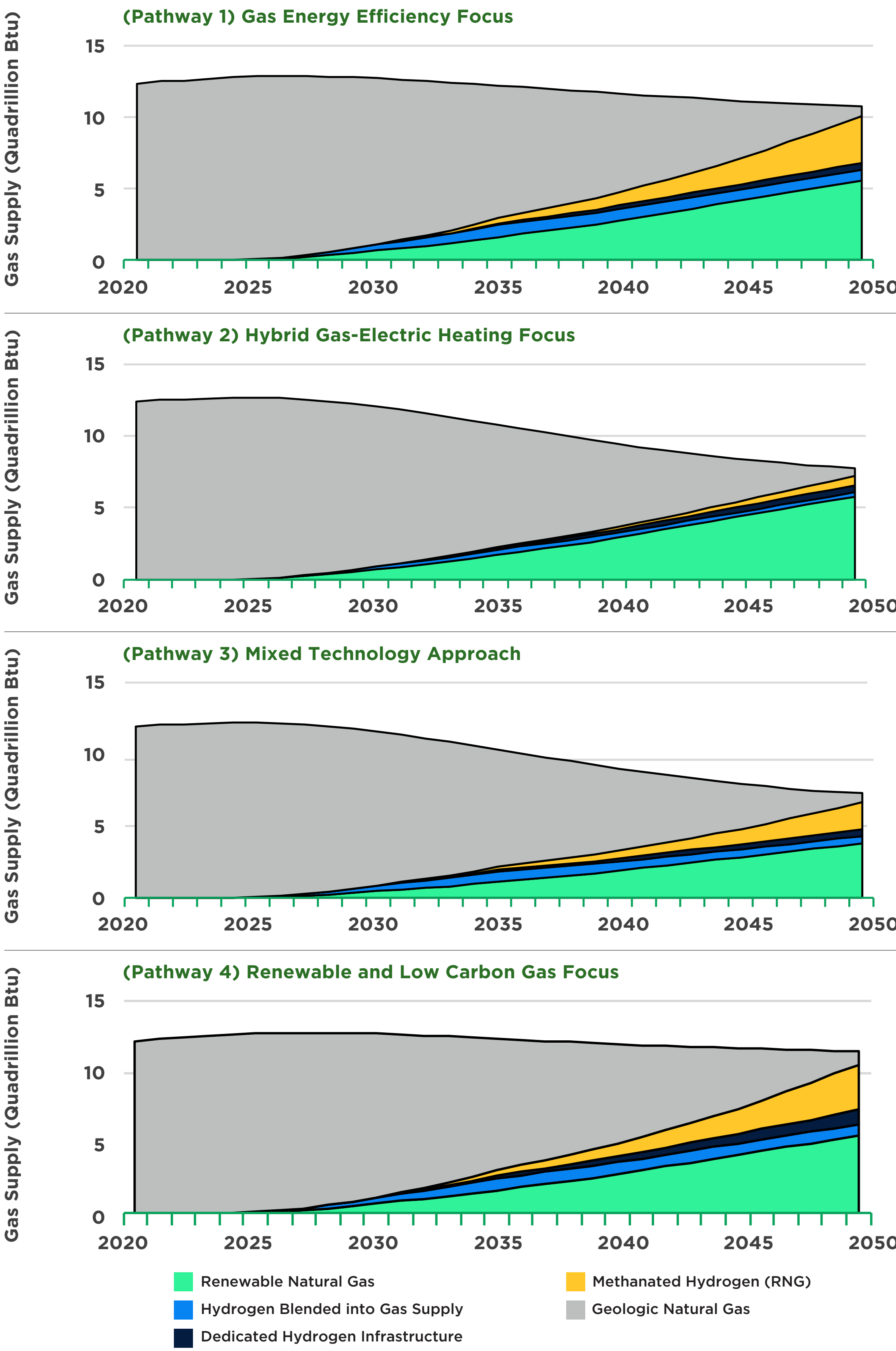
Exhibit 38 – Gas Supply Mix for all Pathways



As an example, in the Gas Energy Efficiency pathway, RNG from anaerobic digestion and thermal gasification is ~51.5% of the energy supply in 2050 (with an additional 30% of supply from methanated hydrogen), hydrogen provides another ~12% of supply (between blending and dedicated H_2 infrastructure) and the last ~6.5% is maintained by geologic natural gas.[114] Across all four pathways, combined AD and TG sources of RNG account for between 48-75% of the 2050 fuel mix, consistently the largest energy contributors to gas supplies in 2050.

114 These percentages reflect the portions of gas supply included in the scope of this analysis – and does not include all sectors currently using natural gas.

Exhibit 39 – Full Gas Supply Mix for All Pathways



As discussed previously, the gas supply mixes used here are intended to showcase a diversity of supply options and do not optimize the supply pathway in coordination with the demand reduction pathway. For example, Pathway 2 uses relatively small amounts of hydrogen on the supply-side and could be reflective of a potential future if current forecasts for significant hydrogen price reductions and supply availability fail to materialize. In all of these pathways, there was sufficient renewable and low carbon gas supply to cover the needs to the customers in the scope of this analysis without using all of the supply that was considered available. **This reflects the significantly expanded expectations for renewable and low-carbon gas supplies discussed in this analysis. The potential to capture a greater portion of RNG feedstocks by 2050, coupled with a broad push for methanating hydrogen feedstocks, can provide even more low carbon supply that gas customers can use interchangeably with their existing equipment.**

4.5 UPSTREAM EMISSION REDUCTIONS

This analysis examined the upstream emissions associated with the production and transportation of gas as an indirect part of gas utilities' GHG inventory. While much of the GHG accounting focus is on customer emissions downstream due to gas combustion (**Exhibit 11** earlier showed to be 81% of the 2020 total), upstream emissions from gas producers and transporters today represent 17% of the GHG emissions related to gas utility operations. Combined with emissions directly from gas utilities (2%), the upstream (17%) and downstream customer (81%) emissions add up to the total fuel life cycle emissions associated with gas utilities, as outlined in **Exhibit 11**. ICF chose to evaluate the full range of emissions associated with gas use to demonstrate how each component can achieve net-zero emissions.

First, due to the significant reliance on RNG across all pathways, ICF inspected the contributing factors to the greenhouse gas intensity of renewable natural gas production in **Section 4.5.1**. Though this report used a combustion emissions accounting approach to customer emissions, there will be upstream emissions from the production and distribution of fuel supplies. In the upcoming **Section 4.5.2**, upstream emissions from all the fuels feeding the gas supply mix (geologic natural gas, renewable natural gas, hydrogen, and methanated hydrogen) are evaluated and consolidated.

There is growing interest in evaluating how the GHG intensity of fuel and electricity sources might change as the economy shifts to net-zero by 2050. ICF chose to mirror its assumptions about decarbonizing the transportation and power sectors from other parts of this study into its calculation of upstream emissions over time for consistency. This assessment is illustrative of what might happen in a decarbonizing economy, not a guarantee.

Currently, upstream emissions are driven by both the scale of the fuel use and the fuel production processes. Geologic natural gas's upstream emissions come from well extraction, processing, and pipeline transport. Renewable natural gas is produced by a variety of approaches with associated emissions depending on the scale of process energy consumption and methane releases. RNG is then fed into the same natural gas pipelines for transport; this evaluation explored how reducing fugitive pipeline emissions could decrease the upstream footprint of geologic and renewable natural gas. This study also modeled upstream hydrogen and methanated hydrogen emissions changing over time as a hypothetical hydrogen supply mix shifted from majority gray (as the market stands today) to 50% blue and 30% green by 2030, gray phased out by 2035, and 25% blue and 75% green hydrogen by 2050.[115] Hydrogen uptake modeled in the customer emissions pathways anticipated hydrogen adoption timelines generally in line with this assumed increase in penetration of clean hydrogen. All electricity (as a processing input) was assumed to be 100% zero-emissions by 2050.

4.5.1 UPSTREAM EMISSIONS FROM RNG PRODUCTION

Renewable natural gas's upstream emissions are a function of emissions released during feedstock transportation, electricity, and geologic natural consumption during production, biogas processing feed loss and flares, and pipeline transmission leaks.

ICF began this assessment by developing illustrative emission factors for current RNG supplies, found in **Appendix D**. ICF evaluated the potential for upstream emissions from all RNG feedstock production pathways included in the AGA Net-zero 2050 RNG resource case by referencing GHG intensity data from Argonne National Laboratory's Greenhouse gases, Regulated Emissions, and Energy use in Technologies Model (GREET) and the California Air Resources Board's (CARB) Simplified Carbon Intensity (CI) Calculators that are based on GREET.[116]

115 Alternate 2050 breakdowns of clean hydrogen would yield similar overall emissions results.

116 California Air Resources Board, LCFS Life Cycle Analysis Models and Documentation https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation

Projections of future improvements in RNG processing and emissions reductions from related sectors were applied to the CI insight from CARB. The result of this analysis is summarized in the RNG upstream emission factors presented below. For example, the upstream emissions from RNG produced at a water resource recovery facility (WRRF) might currently be considered around 37.5 kg CO_2e/MMBtu of RNG, but these could decrease to 6.0 kg CO_2e/MMBtu in a net-zero economy.

Fossil fuel used for vehicular transportation of RNG feedstocks and electricity used in processing those feedstocks are significant contributors to the upstream emissions from RNG production today. Both the transportation and power sectors would be expected to transition to zero emissions options by 2050 as part of the economy-wide push for net-zero emissions. Consequently, zero-emissions vehicles transporting RNG feedstocks and renewable electricity used in RNG processing would contribute zero emissions to RNG production in a net-zero economy. Furthermore, ICF explored how reducing processing and transmission leaks (something the entire gas industry is working towards already) might reduce RNG upstream emissions footprints.

The emission factors in **Table 6** are illustrative and are meant to generally be representative of average resources (not the best- or worst-case scenario) for process emissions in a decarbonized future, which will vary between facilities and regions. An in-depth explanation of how RNG's potential future upstream emissions factors were developed for this report can be found in **Appendix D**.

Table 6 – Example of Potential Low Carbon Future[117] Upstream GHG Contributions by Production Process in the RNG Supply Chain (in kgCO2e/MMBtu)

RNG Feedstock	Transportation	Electricity Consumption	Gas Consumption	Processing Feed Loss & Flares	Transmission Leaks	Gross Positive Upstream Emissions	Avoided Emissions	Net Upstream Emissions
Dairy Manure	0.0	0.0	17.4	4.8	2.4	24.5	-239.5	**-214.9**
Food Waste	0.0	0.0	2.9	3.9	2.4	9.2	-108.6	**-99.4**
LFG	0.0	0.0	0.0	3.5	2.4	5.9		**5.9**
WRRF	0.0	0.0	0.1	3.5	2.4	6.0		**6.0**
Agricultural Residue	0.0	0.0	0.0	3.5	2.4	5.9		**5.9**
Forest Residue	0.0	0.0	0.0	3.5	2.4	5.9		**5.9**
Energy Crops	0.0	0.0	0.0	3.5	2.4	5.9		**5.9**
MSW	0.0	0.0	0.0	3.5	2.4	5.9		**5.9**

As outlined in **Table 6**, dairy manure and food waste RNG supplies offer avoided upstream emissions credits. This means is that there are associated economy-wide emissions reductions tied to dairy manure and food waste getting processed into renewable natural gas. Namely, RNG emissions accounting upstream evaluates the emissions released from feedstock and gas processing, relative to the emissions (methane and carbon dioxide mostly) that would be released if the feedstock materials were not converted into RNG. So, not only does RNG

117 The table shows how a net-zero economy translates into zero electricity and transport emissions and assumes efforts have been undertaken to better measure and reduce methane leaks. Note that the gas consumption category presumes that geologic natural gas would be consumed during RNG processing, rather than a parasitic use of biogas, though using such low-carbon gas supplies would further reduce the upstream emissions from relevant RNG production pathways, as is explained in **Appendix D**.

from these two biogenic resources have net-zero combustion emissions, but their collection and processing into RNG avoids agricultural/food system emissions from a business-as-usual case where the manure and food waste are not repurposed as RNG supplies. It is not guaranteed that these negative emissions can be attributed to or claimed by gas utilities, as it is all predicated on the regulatory structure.

4.5.2 REDUCING UPSTREAM GAS GHG EMISSIONS TO NET-ZERO

Considering the AEO 2021 Reference Case's projection for geologic natural gas demand, without considering alternative low carbon fuel adoption or upstream emissions reductions measures (some of which are already being pursued), would lead to upstream emissions growth between 2020 and 2050 as customers consume more natural gas. However, in the net-zero pathways of this analysis, upstream emissions will shift as the use of geologic gas decreases and renewable natural gas and hydrogen make up a greater portion of the supply mix. As RNG becomes a significant portion of the overall gas supply mix (as shown previously in **Exhibit 39**), emissions reduction actions focused on RNG will be required to lower upstream GHG emissions. In general, the GHG emissions associated with upstream sources are a factor of gas demand and will shift with a changing gas supply and feedstock sources.

Upstream gas emissions can be mitigated through several approaches, including by reducing gas demand, by reducing pipeline gas transmission methane emissions, by reducing the upstream methane emissions from the production of geologic gas, by leveraging renewable and low carbon gas supplies, by reducing the processing emissions from renewable and low carbon fuels, as well as by reducing any fugitive emissions of gas from renewable natural gas.

Exhibit 40, **Exhibit 41**, and **Exhibit 42** below demonstrated an illustrative combination of these emission reduction approaches. Upstream emissions are calculated based on the changes in customer demand and gas supply over time. Customer Pathway 4 is featured in these exhibits, but all the pathways studied here would provide similar upstream emissions outcomes. The following categories are specifically highlighted in the chart:

- **Upstream emissions reductions for geologic natural gas:** Geologic natural gas can be produced and transported in a manner that minimizes methane emissions. Various entities are now interested in establishing standards or certification programs for what is sometimes called 'differentiated' or 'certified' gas. ICF's analysis assumes that methane emissions from pipeline transmission leaks and the processing of geologic natural gas decrease by 50% by 2030, reducing total geologic natural gas upstream greenhouse gas emissions by about 25% (since methane accounts for approximately half of the overall upstream emissions for geologic gas). This emissions reduction pathway can ramp up relatively quickly, but the emission reductions achieved are reduced over time as the level of geologic gas being used declines out to 2050.
    - Because renewable natural gas generally flows through the same pipelines as geologic natural gas, the pipeline methane emissions improvements were also applied to the RNG upstream emissions evaluation, as outlined in the previous section.
    - Though not modeled in this report, there may be opportunities to further reduce upstream emissions from the geologic gas supply chain (e.g., via efficiency improvements, process electrification, or the use of low-carbon fuels in processing).

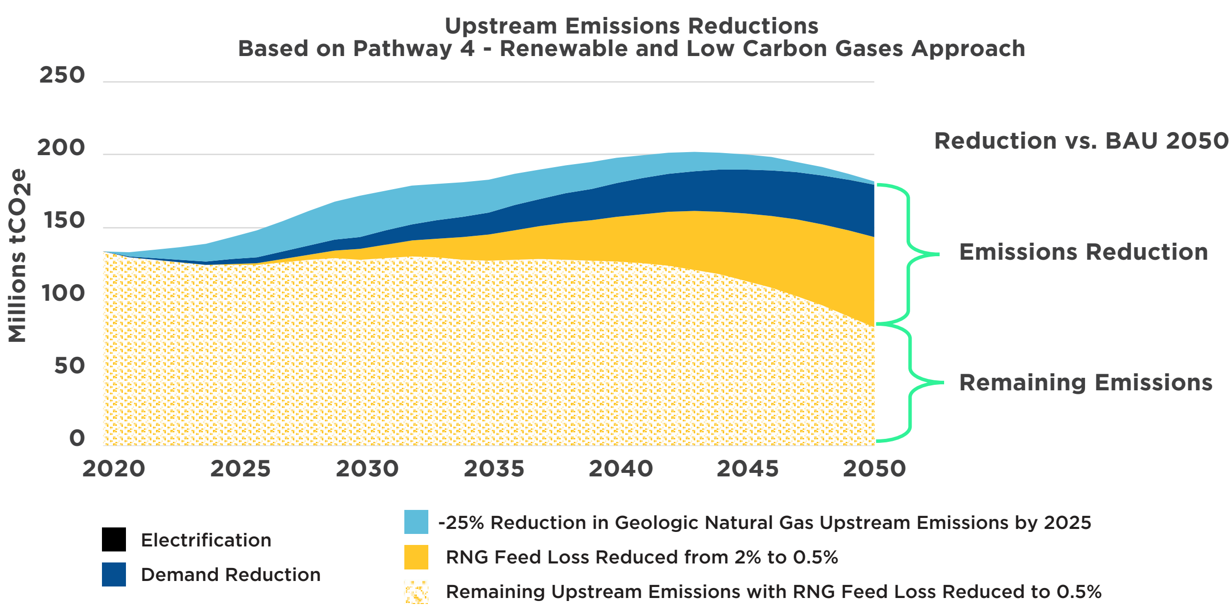
- **Gas demand reductions:** Demand reduction was an important factor in reducing customer emissions. Reductions in customer gas demand (based on this chart on customer Pathway 4) also reduce the upstream emissions associated with the avoided gas use. Efforts to engage customers in gas end-use equipment and building efficiency improvements, behavioral programs, selective electrification, and appliance swaps to run on alternative low- and zero-GHG emissions fuels all reduce gas demand. Note that added upstream electricity emissions from newly electrified measures are out of scope for gas utilities' upstream emissions (not included in the upstream emissions charts shown here).[118]

- **RNG feed loss reduction:** This represents industry action to establish more accurate measurement procedures for RNG processing and programs to eliminate any fugitive emissions from this stage of RNG production. As discussed in **Appendix D**, most analyses assume a 2% methane leak from this stage because metering accuracy does not allow for actual values to be used. This analysis assumes that this could be reduced to 0.5%, while lower emissions are likely possible.

- **RNG avoided emissions:** This represents the upstream emissions reductions from certain types of RNG production, which can divert carbon dioxide emissions and avoid prevent the release of methane to the atmosphere. Animal manure and food waste RNG projects capture methane and, in some cases, divert carbon dioxide that would not otherwise be mitigated if the organic waste was left to decay as usual.

In modeling upstream emissions, ICF is accounting for the 17% of greenhouse gas emissions tied to the gas utility emissions inventory pie chart outlined in **Exhibit 11**, showing how the full supply chain can target net-zero emissions. **Exhibit 40** demonstrates the upstream emissions from geologic natural gas, hydrogen, methanated hydrogen, and RNG used in Pathway 4 (Renewable and Low Carbon Gas Approach).[119] The graph does not account for the avoided GHG emissions associated with the production of some RNG feedstocks. It demonstrates how measures to reduce gas use, like reductions in gas demand by customers, also yield upstream emissions reductions.

Exhibit 40 – Gross Upstream Gas Emissions (Excluding Avoided Emissions from RNG)



118 Note that for electric utilities, electrification would yield growth in their upstream emissions when electricity generation is not renewable / zero-emissions.

119 Targeted electrification was not featured in Pathway 4, and therefore there are no upstream gas sector emission reduction contributions from electrification shown in **Exhibit 40** or **Exhibit 42**.

When alternative fuel resources come online, they displace geologic gas and its upstream emissions profile. Per **Table 6**, the upstream emissions associated with RNG coming from animal manure and food waste are very net-negative. As more RNG from these sources is integrated into the Pathway's gas supply, more avoided emissions credits are generated. Though the other RNG feedstocks contributing to this study's RNG resource potential have slightly net positive upstream emissions, the fraction of RNG resources from food waste and animal manure yield overwhelmingly large amounts of avoided emissions. The scale of RNG adoption modeled resulted in significant avoided upstream emissions. This is highlighted in **Exhibit 41**, which focuses on 2050 and shows the cumulative impact of different upstream emissions reductions opportunities. The avoided emissions that animal manure and food waste RNG production generate in Pathway 4 are shown in green. Total avoided emissions (~227 MMT CO_2e in illustrative Pathway 4) are split in two bars in the chart, into an amount equal to Pathway 4's 81 MMT CO_2e of remaining positive upstream emissions in 2050, and the ~146 MMT CO_2e of more emissions avoided; if the avoided emissions were all attributed to gas utilities (predicated on a regulatory structure that may change), upstream emissions could surpass net-zero and be net-negative in total.

Exhibit 41 – 2050 Net-zero Upstream Gas Emission Reductions

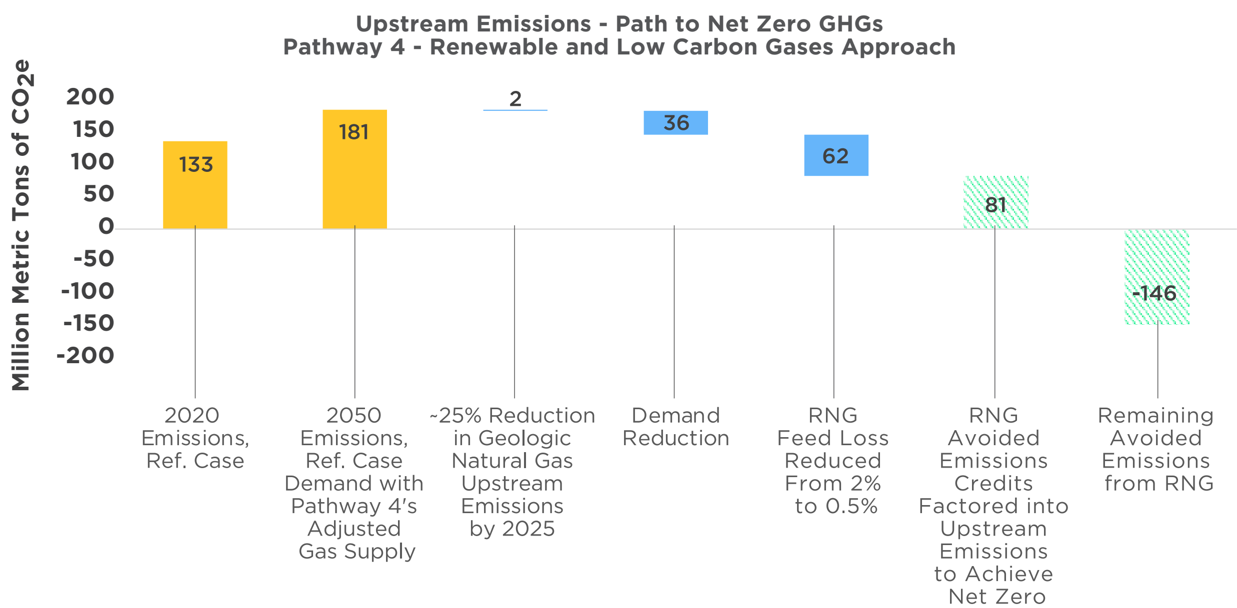
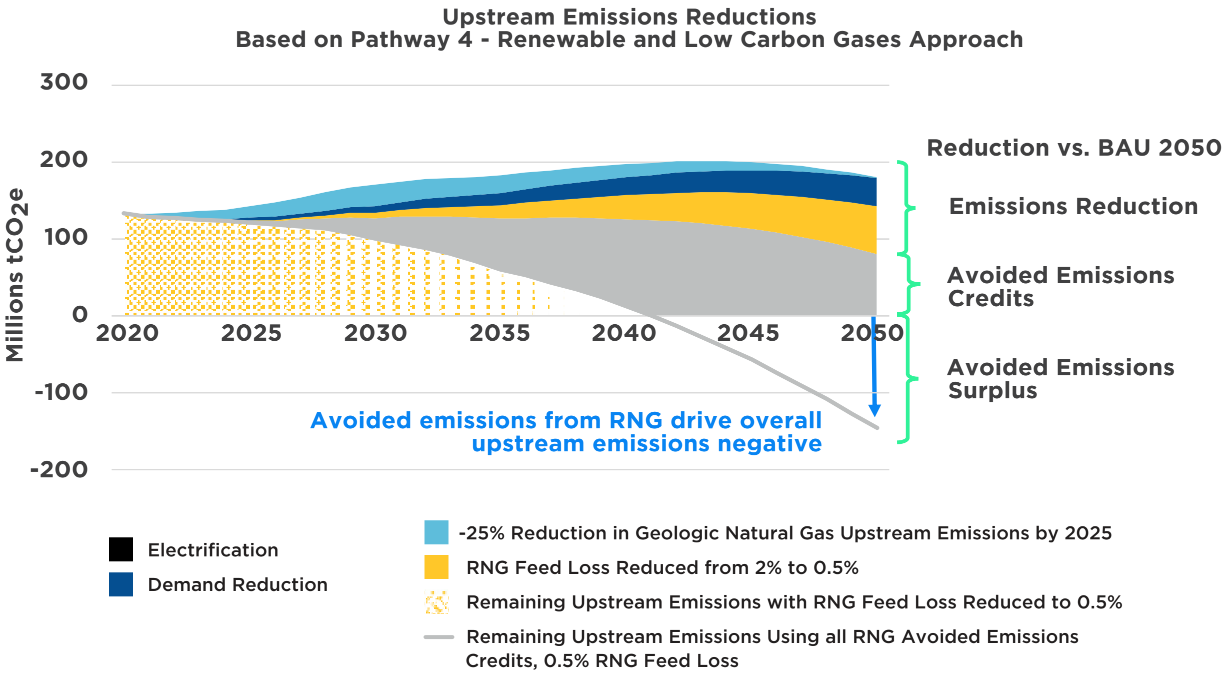


Exhibit 42 showcases how the upstream emissions profile changes over time. In this case, the avoided emissions that RNG production generates in Pathway 4 are shown in the gray wedge. From a net upstream perspective, incorporating the avoided emissions facilitates total upstream emissions reaching net-zero ahead of a 2050 net-zero target. The gray line in **Exhibit 42** demonstrates how the full availability of RNG avoided emission credits could cut into upstream emissions. Eventually, enough RNG is in use such that more emissions are avoided than generated upstream. Of course, the RNG avoided emissions credits could be accounted for differently than in the illustrative exhibit below; as shown in **Exhibit 40**, allocating the avoided emissions elsewhere would leave a fraction of positive upstream emissions in the absence of other reduction measures upstream. If the avoided emissions from RNG are not credited to the RNG producer, investment in offsets or negative emissions technology would be required.

Exhibit 42 – Pathway to Net-zero Upstream Gas Emissions



4.6 DIRECT GAS UTILITY EMISSION REDUCTIONS

4.6.1 UNDERSTANDING SOURCES & CURRENT QUANTIFICATION OF GAS UTILITY EMISSIONS

Direct emissions for natural gas distribution companies consist primarily of fugitive and vented methane emissions. As shown in **Exhibit 11**, these represent roughly 2% of total gas utility direct and indirect emissions. Methane has a much higher global warming potential than carbon dioxide. The next largest direct gas utility GHG emission source is the carbon dioxide from the combustion of natural gas at the companies' storage compressors, LNG operations, facility space heating equipment, and vehicle fleets. Lastly, there are much smaller emissions from fugitive and vented carbon dioxide and some nitrous oxide emissions from combustion.

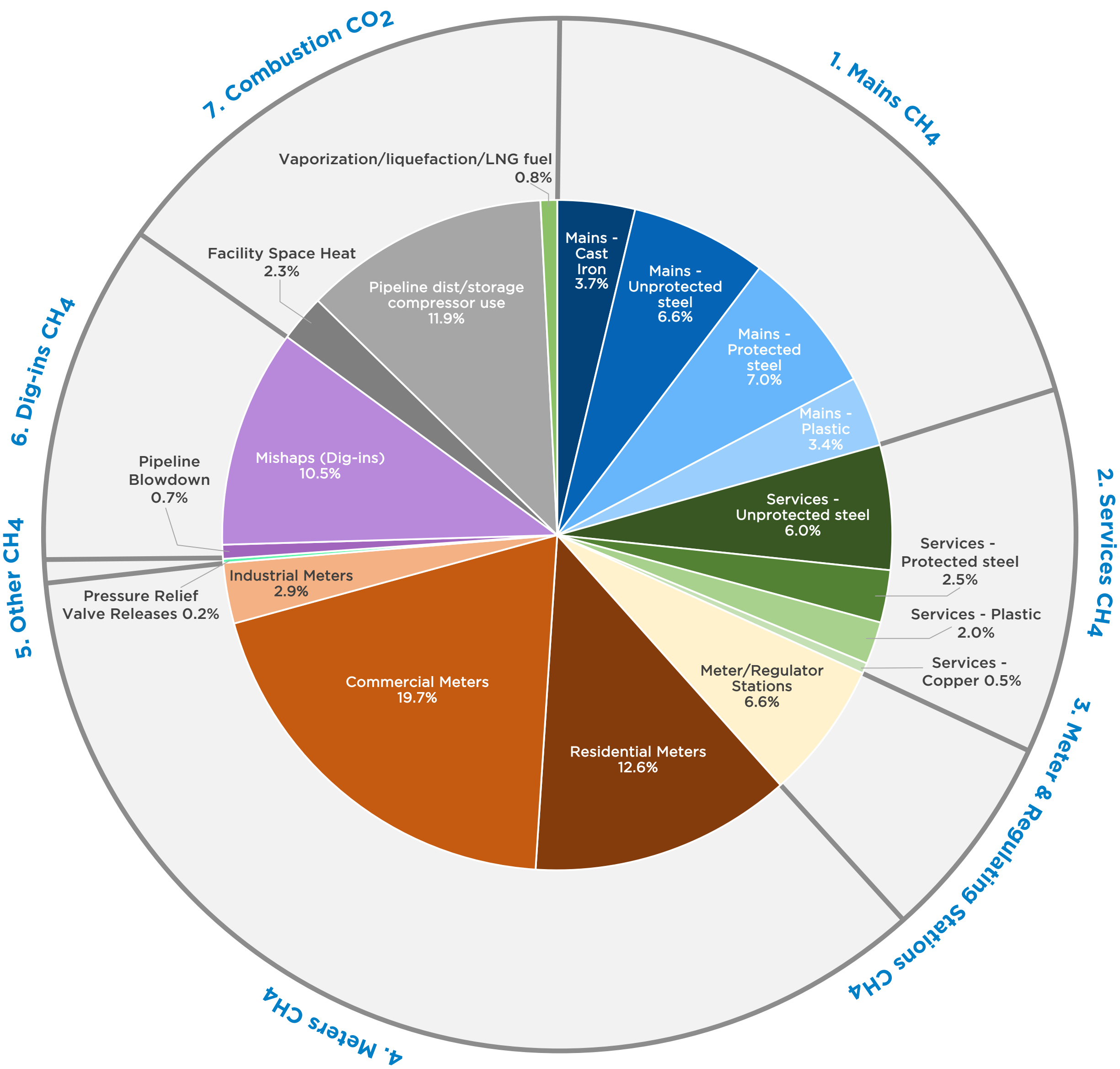
Exhibit 43 focuses on the largest sources of emissions making up the natural gas utilities' footprint, focusing on methane and combustion emissions. The methane emissions estimates come from EPA's latest Inventory of U.S. Greenhouse Gas Emissions and Sinks covering emissions in 2019 from Petroleum and Natural Gas Systems (published in April 2021)[120] while the combustion emissions were estimated from EIA's Form 176 reported data in 2019 for companies with deliveries to residential and commercial customers.

120 United States Environmental Protection. Natural Gas and Petroleum Systems in the GHG Inventory: Additional Information on the 1990-2019 GHG Inventory (published April 2021) https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2019-ghg

There are a few key take-aways from this break-down of 2019 emissions:

- **Four Areas Represent More Than 90% of Direct Gas Utility CO_2e Emissions:**
    - Pipeline (mains and services) methane emissions represent roughly 32% of the total
    - Meter methane emissions represent roughly 35% of the total
    - Mishaps (dig-ins) or third-party damage to pipes represent roughly 11% of the total emissions
    - Combustion CO_2 emissions represent roughly 15% of the total

Exhibit 43 – 2019 Natural Gas Distribution Stage Direct Greenhouse Gas Emissions (16.5 Million Metric Tonnes CO_2e Total)[121]



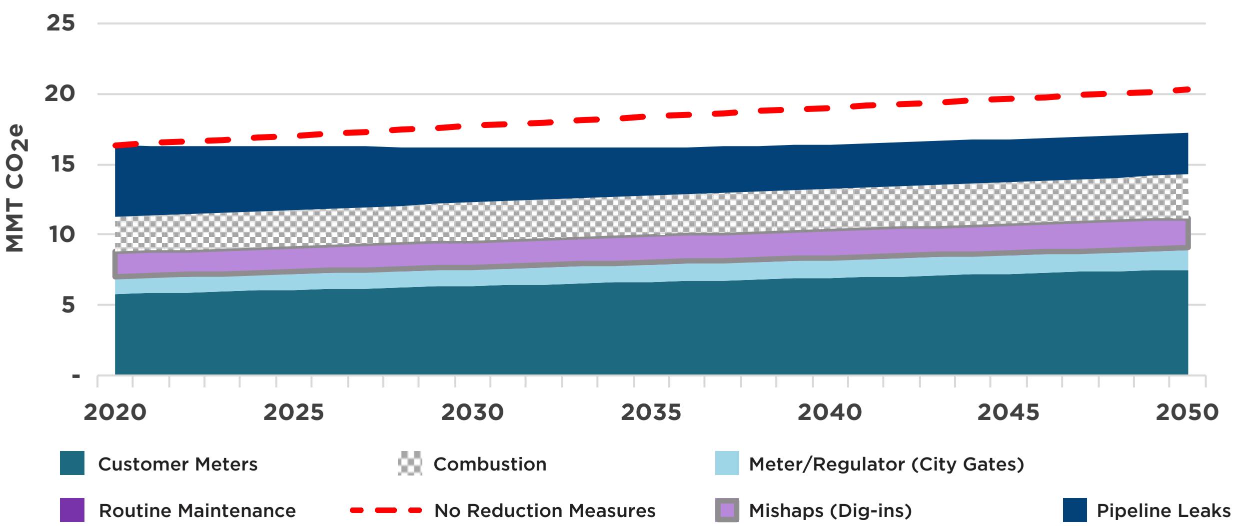
121 Emissions represent methane emissions from U.S EPA's Natural Gas and Petroleum Systems GHG Inventory along with combustion emissions associated with gas use reported in EIA's Form 176

- **There Are Limitations to the Use of EPA Emission Factors in Quantifying Utility Methane Emissions:**
    - EPA emissions factors represent average emissions as applied to a specific activity, such as pipeline mileage or meters. Using EPA emission factors, the only way to measure and report reduced estimated gas utility emissions is to reduce pipe mileage, replace unprotected steel and cast-iron pipe with plastic or protected steel, or reduce the number of meters or customers. The use of EPA emissions factors limits the ability for a specific gas utility to take credit for certain actions to reduce methane emissions. Examples of these limitations include:
        - Using an emission factor per mile of different types of pipe means that utilities cannot get credit for repairing or avoiding leaks in their pipeline (because it does not change the number of miles).
        - Using an emission factor per customer meter means that utilities also cannot get credit for avoiding or repairing leaks at meters.
        - Dig-in or mishap emissions factors are also based on miles of pipeline, and do not capture efforts to reduce these events.
    - EPA factors may also overstate emissions, and this may be particularly true when applying the national emission factors to individual companies.
    - EPA factors (current and historical) are updated periodically, which makes it harder to track utility progress in this area, as there can be a sudden large shift in reported emissions based on an emissions factor update, and changes to historical reported results also may change the level of reductions that have been achieved to date.
    - EPA factors are a 'national average', while some of the studies they are based on show significant variation in, for example, meter emissions by region.

4.6.2 REFERENCE CASE CHANGES TO GAS UTILITY EMISSIONS

Under the current construct for measuring emission inventories (EPA emission factors), a gas utility experiencing growth in gas customers will increase direct utility emissions, as more infrastructure is added, including mains, gas meters, and service lines. New pipelines will average lower emissions than vintage pipe. The graphs below approximate what increasing emissions might look like, based on the residential and commercial customer growth assumed in the customer GHG pathways from this analysis. The growth factors are adjusted for pipeline mileage, as historically pipeline mileage has grown at a slower rate than customer meters, since once the infrastructure is in place, it takes less to add the next customer. The red dashed line in **Exhibit 44** shows growth without any other changes, assuming all equipment categories increase according to these growth patterns, while the bars in the rest of **Exhibit 44** account for the effect of existing expectations for integrity management programs to replace all cast iron and unprotected steel pipe by following the same pace of replacement as seen over the last five years.

Exhibit 44 – Projected Distribution Utility Emissions with Vintage Pipeline Replacement Programs



4.6.3 GAS UTILITY DIRECT GHG EMISSIONS REDUCTION PATHWAYS

There are a variety of measures that gas distribution companies can implement to reduce emissions within their direct emissions footprint. As stated earlier, most emissions come from four primary sources, including meters, pipelines, combustion, and dig-ins/mishaps, so it is particularly important to reduce emissions from these sources. A combination of these emission reduction approaches is demonstrated in **Exhibit 45** below. While this illustrative pathway is calculated based on the changes in customer demand and gas supply from Pathway 4 of this study, all the pathways studied here would provide similar direct utility emissions outcomes.

Exhibit 45 – Pathway to Net-zero for Gas Utility Direct Emissions

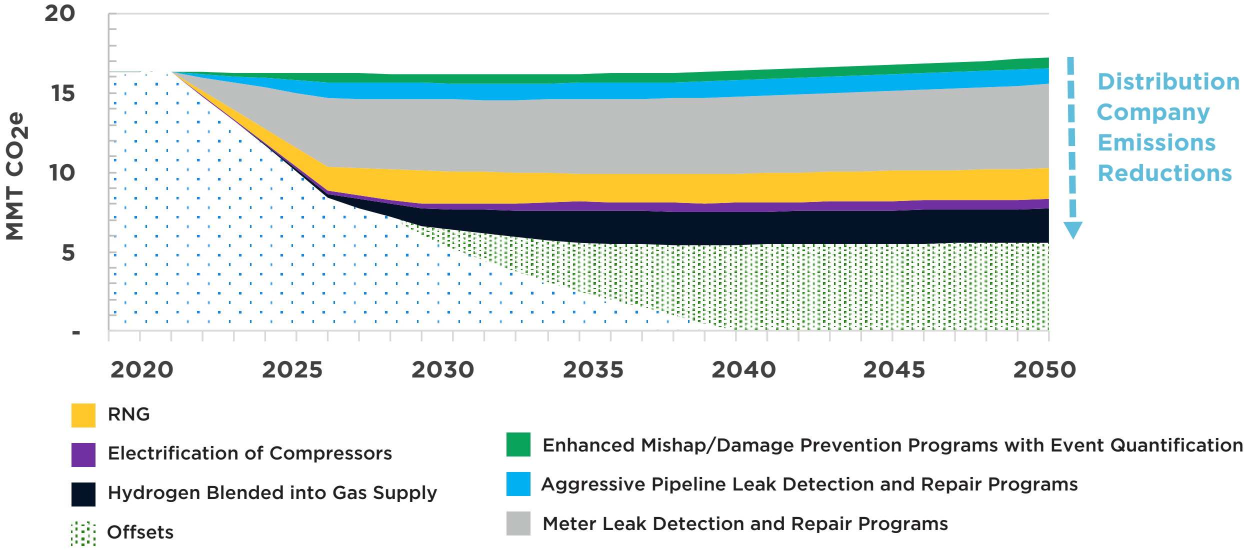


Exhibit 45 presents a variety of emission reduction opportunities, and the assumptions and justifications for each of these are outlined as follows:

- **Meter Emission Reductions:** The EPA methodology for meters is based on a fixed emission factor per meter. Limited data on actual leak surveys and measurements for residential meters suggests that actual emissions could be lower than the EPA factor. In addition, LDAR programs targeted at the largest leakers would significantly reduce emissions. The EPA recently adjusted its assumed commercial and industrial meter emissions in part due to a recent GTI survey that suggested that these meters are leaking at higher rates than previously believed.[122] Companies currently have integrity programs to evaluate meter sets on typically a three- or five-year rotating basis that can provide more accurate, company-specific data on leaks. Incorporating a repair aspect to these programs can achieve documented emission reductions. The GTI study showed that emissions from meters had a "fat tail" distribution, meaning that a small number of leaking meters resulted in the bulk of the emissions. Reducing the top 10% of leaks from meters could account for the majority of leaks. Furthermore, the GTI data showed large differences by region in the meter emissions. For this study, ICF assumed the potential for a 70% reduction of emissions. ICF estimates that addressing the "fat tail" through LDAR programs and documenting actual emissions would likely enable utilities to achieve this level of reduction.
- **Pipeline Emission Reductions:** The baseline for the emission projections accounts for companies replacing all cast iron pipe by 2032 and all unprotected steel pipe by 2050 following the same pipeline replacement speed they have averaged over the past five years. While these programs could be expedited, companies can still achieve reductions beyond what the EPA emission factors would account for by more aggressively targeting repairs on Grade 2 and 3 leaks and expediting the schedules for these. Companies that have recently (past two years) started programs that measure and prioritize repairing their larger-emitting non-hazardous pipeline leaks have seen reductions of 20% from EPA's emissions assumptions. As such, for this analysis, we assumed that companies can average 20% reductions from EPA's emission factors through

122 U.S. EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2019: Updates for Natural Gas Customer Meter Emissions, April 2021. Available at https://www.epa.gov/sites/default/files/2021-04/documents/2021_ghgi_update_-_meters.pdf

aggressive LDAR programs that were started and increased from 2023 to 2027 and through the development of company-specific estimates that account for these programs.

- **Mishap/Dig-ins Programs:** Various AGA members estimate their emissions for each of their reported mishaps using a variety of estimation techniques based on the pressure of the pipe, the size of the pipe, and the duration of the leak. From this data, we can make a comparison to EPA's figures for emissions from mishaps/dig-ins divided by PHMSA's total number of dig-in events. Companies are seeing dig-in emissions as low as one-third of what EPA's factor would suggest. This reduction can, in part, be attributed to where the dig-ins are occurring on the line, but it is also largely due to the proactive programs companies have implemented to reduce dig-ins. Not all companies have seen reductions from EPA's factors, and it can fluctuate from year to year. Still, overall, by taking the median from respondents, it is prudent to conclude that through increased prevention and mitigation measures and more visibility, companies can reduce mishaps/dig-ins up to 30%, and some company experiences have demonstrated a reduction in the number of incidents over time. Accounting for these lower emissions will require the use of company-specific measurement and reporting.
- **Electrification of Compressors:** The electrification of compressors can reduce combustion emissions and, as the grid is decarbonized, also reduce indirect electricity generation emissions. That said, compressor reliability is critical to the operation of the gas system, and electric compressors require backup power supplies to ensure operability during power outages. For this study, emissions from compressors were assumed to be reduced by up to 25% by 2035 through a limited replacement of older compressors with electric compressors, which reduces emissions while ensuring reliability. Alternatively, the compressors could be fueled with RNG.
- **RNG:** For the remainder of on-site natural gas combustion emissions, gas utility companies can fully mitigate their direct emissions by adding RNG projects and applying the environmental attributes associated with RNG to their utility combustion emissions instead of their customer's emissions. Across all four study pathways, there is sufficient remaining RNG within the 'AGA Net-zero 2050 Case' to negate these direct utility combustion emissions after accounting for customer use.
- **Hydrogen Blended into Gas Supply:** To the extent that hydrogen increases in the gas stream and the methane content decreases, fugitive leaks will also have a lower GHG impact proportional to the decrease in methane content, as hydrogen is not a GHG. For **Exhibit 45**, the hydrogen blended ranged from 0.5% in 2025 to 20% by 2035. Emissions from the system were reduced proportionately to the increase in hydrogen as methane content would decrease.
- **Offsets and Negative Emissions Technology:** Lastly, as it is not possible to reduce 100% of methane emissions, since some level of leaks will still occur regardless of how aggressively one finds and repairs them, companies can utilize offsets to reduce the footprint of residual leaks. In the example chart above, offsets for the residual emissions were scaled up from 2030 to 2040 to account for 100% of the residual emissions. While different sources of offsets or negative emissions technologies could be used to cover residual emissions, the surplus avoided emissions from the upstream emissions pathways (**Section 4.5.2**) would more than cover the need for offsetting residual gas utility emissions.

5 DISCUSSION OF TYPES OF POLICY & REGULATION NEEDED TO UNLOCK PATHWAYS

Reaching net-zero emissions targets will require a transformative change to energy systems and the economy. Decarbonization of the economy will require a broad mix of regulatory and policy drivers to initiate, sustain, and support the transformation. Analysis will be necessary for all regions to find the most effective, equitable, viable, and least-cost path that is in the best interest of all stakeholders. Policies should be designed to accommodate change as scientific knowledge, technology options, and other circumstances evolve.

New policies and regulations will be needed to define and structure requirements and incentives for reductions and to provide the regulatory support and funding for implementation. The success of any emission reduction plan will depend highly upon the structure and support of public policy. Federal, state, or local policies should be designed to consider and leverage natural gas infrastructure and end-use applications in meeting greenhouse gas emissions targets.

The analysis in this report showcases several key emissions reductions opportunities for gas utilities and their customers across all net-zero pathways, including energy efficiency, renewable and low carbon fuels, building energy codes, differentiated gas, and methane leak detection and repair programs. However, gas utilities cannot implement any of these decarbonization pathways on their own. Utilities operate under strict regulations by state and federal regulators and must adhere to many rules and processes. Many or most of the actions that gas utilities can take to reduce carbon emissions will require approval from regulators. To enable adoption of the technologies and pathways to net-zero highlighted in this report while protecting customers, regulators may need additional flexibility to existing regulations and policies related to utility cost recovery, building codes, allocation of costs based on benefits, customer equity, and a variety of other issues will be needed.

A partial list of examples is provided below.

1. Supporting Expanded Utility Energy Efficiency and Demand-Side Management Programs

Deployment of many of the measures envisioned in this study could be supported by utility energy efficiency programs. Natural gas utility demand-side management (DSM) programs have a strong track record of driving cost-effective reductions in customer gas use and corresponding GHG emissions. Several of the demand-side measures in this study are already supported by utility DSM programs in various parts of the country. Expanded and new DSM programs, across more regions, will be needed to help customers reduce their gas use. Inclusion of additional measures or the use of higher incentives, increased marketing budgets, and alternative delivery approaches (e.g., direct install or midstream/upstream programs) may incentivize further measure adoption. Upfront incentives may be particularly important to overcome the higher first costs associated with more efficient technologies, including existing technologies and advanced technologies like gas heat pumps. Under supportive legislative frameworks, utility energy efficiency program budget increases could be supported by cost-effectiveness testing that reflects the value of GHG emissions reductions, allowing more measures and programs to meet the required cost-benefit analysis screening criteria.

2. System Modernization Programs Can Contemplate the Future Use of Renewable Gases Including Rng and Hydrogen

The pathways in this analysis all continue to leverage gas infrastructure to support a net-zero greenhouse gas emissions energy system. As such, it will be vital to continue to update and modernize the gas infrastructure. Different regions have achieved varying levels of modernization to date, but there is a strong push by gas utilities to replace older cast iron, unprotected steel, and vintage plastic pipe with modern piping options. While this is driven primarily by safety considerations, system modernization also makes important contributions to reducing methane emissions, and in the future may also be adapted to prepare infrastructure for hydrogen adoption. Modernization initiatives can also include gas meter replacement programs, both to achieve methane emissions reductions and for more precise monitoring of gas consumption.

3. Research, Development, and Demonstration (RD&D) Funding for Low Carbon Gas Technologies

As with all pathways to net-zero emissions targets, the pathways in this study include many emerging technologies that would benefit from additional Research, Development, and Demonstration (RD&D) funding support. This includes technologies such as RNG production via thermal gasification processes, hydrogen blending and methanation, and gas heat pumps.

For example, RNG is generally considered critical to meet net-zero targets. However, various studies' different views on the amounts of RNG available can influence how RNG is allocated to end users and customer types. While this study contemplates that more RNG supply is possible, the need and usefulness for low-carbon gases provide additional impetus for RNG as a critical area for RD&D funding to unlock greater amounts of supplies. Funding announcements for hydrogen projects have grown substantially in recent years, however, R&D investment in RNG and biogas production projects have been significantly smaller. Consider large-scale government-funded investments designed to lower solar PV production costs as an example of how R&D investments in production improvement for emerging technologies can support efforts towards the viability of the technology. Like hydrogen, RNG is an important area of opportunity for RD&D, where funding investments could serve to reduce costs and result in emission reduction pathways. But, unlike hydrogen that is in the infancy stages of R&D, the use of RNG to lower emissions can be realized in the near term.

Additionally, utilities and their customers would benefit from flexible funding designed to support the work necessary to facilitate the transition to a low, or zero, emissions future.

4. Create Market Structures and Incentivize Demand for Renewable and Low Carbon Gases

Renewable and low carbon gases are an integral component of the net-zero pathways in this analysis. The development of significant volumes of low carbon gaseous fuels like RNG and eventually hydrogen delivered into the natural gas supply is a realistic approach to emission reduction goals but will require appropriate policy and regulatory support. In regions where RNG is already required or incented, significant volumes of projects have been developed facilitating the decarbonization of the gas supply. However, most natural gas utilities in the country do not have the permitted regulatory approval necessary to purchase renewable or low carbon gases on behalf of their customers.

Public utility commissions and regulators seek to protect the public interest and ensure safe and reliable utility service at reasonable rates. Traditionally, this has meant utilities are expected to demonstrate that the costs they seek to recover from their customers reflect a prudent approach that ensures criteria are met for safety, reliability, affordability, and other conditions. Some state legislatures and public utility commissions have begun to factor in broader societal benefits from GHG emission reductions (e.g., a social cost of carbon) and state GHG emission targets into prudence reviews. However, in most cases, the public utility commissions and the gas utilities need legislative approval to implement the inclusion of RNG and hydrogen into gas supply portfolios and associated cost recovery mechanisms.

Several legislative approaches could be used to incentivize the adoption of low carbon resources into the gas supply mix. These can range from a Renewable Gas Portfolio Standard (RGPS), similar to Renewable Portfolio Standards (RPS) which is a common policy tool to introduce a renewable energy procurement mechanism for electricity providers, to a state-wide or industry-specific emissions reduction target. The extent to which these approaches are adopted at the state or federal level and the ambition of programs will impact RNG demand and ultimately determine how the RNG supply market responds.

Other options to support the deployment of low carbon fuels could include expansion of the production tax credit program to include RNG and other low carbon fuels to bring down project costs, or a consumption tax credit that makes the purchase of RNG and other low carbon fuels more affordable for consumers.

5. Coordinated Gas and Electric Planning

In order to understand the full range of implications and alternatives, as well as to determine the lowest cost pathways for customers, infrastructure planning for energy systems in a decarbonized future should be done in an integrated manner, instead of studies being conducted in silos for each energy system. This will require coordination across state, regional, and even federal jurisdictions and with input from different stakeholders with an array of expertise across multiple domains including technical, policy, legal, and regulatory. There will be crossover between electric and gas technologies and opportunities for each to serve the role they are best positioned for and to support a more integrated and optimized pathway to emissions reductions.

6. Utility Revenue Decoupling and Cost-Recovery Updates

While the degree varies by scenario, the pathways shown in this study include significant reductions in per-customer gas use by 2050.

Under traditional regulation, utilities recover fixed costs through consumption charges. When consumption is increasing, this is favorable for utilities. However when sales fall, utilities may not recover all their fixed costs, which can create a dis-incentive for utilities to support actions such as energy efficiency that would reduce customer consumption (and GHG emissions).

For this reason, more than half the states have already adopted ‘decoupling’ mechanisms for natural gas utilities as part of removing barriers to utility energy efficiency programs. Decoupling will be increasingly important for gas utilities under net-zero pathways to ensure all parties are incented to support GHG emission reductions. To ensure alignment of all parties, it may be beneficial to evaluate decoupling (or other alternative forms of cost-recovery) in states where it does not exist, and update decoupling mechanisms in states where it exists but the specific rules do not adequately account for the scale and speed of transition envisioned in these pathways.

Similarly, compensation and cost-recovery adjustments will likely be needed to reflect large changes in the utility business model and to allow and incent new types of decarbonization investments.

7. Structures to Address Cost Allocation and Consumer Equity Issues

All types of net-zero pathways, including those not studied here, involve the transformation of energy systems and the economy. Such drastic changes can be difficult to quantify precisely but can be expected to have significant cost implications and raise questions about how equity related to the distribution of opportunities and impacts across all customers can be factored into plans. For example, customers that can participate in energy efficiency programs will be less impacted by rate increases, but customers who are less able to participate (e.g., low-income customers) and reduce their consumption will likely be more impacted as a result of higher costs. Adjustments to rate structures and utility funding mechanisms will likely be required to ensure an equitable transition and avoid placing a disproportionate burden on certain customer groups.

8. Option to Use Company-Specific Methane Emissions Factors

Several approaches to drive deep reductions in utility methane emissions may require new and innovative approaches to measuring and accounting for methane emissions mitigation. The use of direct measurement of methane emissions, rather than use of standard, fixed EPA emission factors, can open up new opportunities for gas utility direct emissions reductions.

The generic EPA emission factors currently used to calculate methane emissions preclude a company from the recognition that they have reduced methane emissions. For example, calculating emissions from meters using the EPA emission factor multiplied by the number of customer meters means that a utility's emission report to the EPA would not recognize a proactive program implemented by the utility that detects and repairs leaks at meters (the only way to reduce calculated emissions with EPA factors is to reduce the number of meters).

Company-specific methane emission factors based on direct measurement can replace the generic EPA emission factors currently in use. Each company's development of more accurate measurement protocols paired with expanded leak detection and repair programs would provide emission factors that reflect each company's experience and emission reduction efforts more accurately. Allowing some companies to choose to use this novel approach will require collaboration from industry, the EPA, and other stakeholders to establish a robust and transparent process to improve the accuracy of methane emission reporting.

9. Support for Developing Hydrogen Market

For hydrogen supply and end-use demand to develop, there are several areas in which this emerging fuel option would require support:

- **RD&D support:** Funding support for research into hydrogen transportation, distribution, storage in dedicated systems and the existing natural gas network. Also, research to evaluate of impacts of hydrogen in natural gas end-use equipment.
- **Incentives:** Incentives for hydrogen production and use to overcome near-term cost hurdles.
- **Pilot projects:** Expansion of pilot projects to identify technical, economic, policy, and regulatory barriers for the use of hydrogen as a fuel.
- **Blending agreements:** depending on the pathways to hydrogen deployment, standards governing operating parameters such as allowable blending levels will be required for both distribution and transmission systems. Where hydrogen is injected directly into the distributions system, state regulators will need to approve governance structures and rules (similar to RNG). For

hydrogen to be injected into the interstate transmission system tariffs under the jurisdiction of the Federal Energy Regulatory Commission may need to be updated, as well as the re-negotiation of some commercial agreements.

- **Codes and standards:** For hydrogen to be adopted as a fuel, codes and standards governing its use need to be established (e.g., building codes, fire codes, etc.).

10. Improved Building Codes for New Construction That Reduce Heating Load but Maintain Fuel Choice

The pathways in this study include expectations for newly constructed buildings to be significantly more energy-efficient. While incentives for better building practices are part of some existing utility programs and may play an important role in the transition, achieving very high levels of compliance will likely require updates to building codes to mandate these improvements.

The building codes included in some pathways of this analysis are modeled on one of the leading energy building codes in North America, British Columbia's Energy Step Code. This code progressively builds up the required efficiency improvements towards a goal of buildings achieving an 80% reduction in heating load by 2050. The building code itself is 'fuel-neutral' and leaves options for both gas or electric heating equipment.

The process for developing new building energy codes will be driven by national and international consensus organizations and implemented at the state and local level. Still, the engagement of the federal government and other stakeholders can provide standardized supporting materials and guidance to facilitate these processes.

11. Compensating Gas Customers for Cost Savings They Achieve for Electric Customers

In addition to continuing to serve gas customers (with reduced annual throughput), maintaining gas infrastructure on net-zero pathways is likely to offer several benefits to the electric grid and electric customers. This could be through energy storage, load flexibility, and peak shaving provided by a range of different gas measures and technologies.

One specific example included in the illustrative pathways in this study would be hybrid gas-electric integrated heating systems. In these arrangements, an existing gas customer would replace their air-conditioning unit with an electric air-source heat pump, which can provide both heating and cooling, but maintain their existing gas furnace to provide supplemental heating instead of installing electric resistance backup heating. This dual-fuel system can limit the growth in electric peak demand and could provide flexibility to the electric system (for example, hybrid system could switch from electric to gas heating if the electric grid is experiencing a period of low levels of generation from intermittent renewable sources). Hybrid heating systems are not without challenges and would require different regulatory structures to accommodate them.

While the hybrid heating systems and other gas measures to support the electric grid may reduce overall energy system costs, the reduced gas sales volumes from hybrids would put upward pressure on gas rates to avoid rate increases on electric customers. As such, there may be a need to study how gas and electric utilities can partner to recognize the value each system brings—and compensate their corresponding customers equitably.

Regardless of the approach taken, decarbonization will require the involvement of a wide range of policymakers and other stakeholders making choices with the potential to result in significant impacts on a wide range of consumers. Customer bills, the environment, the economy, energy reliability, and many other areas will be affected by emissions reduction initiatives. Consequently, utility regulators will need to be engaged at every level. In addition to local, state, and federal regulators, legislators, and executive branches, other kinds of regulators (for example, regional organizations like electric independent system operators or the North American Electric Reliability Corporation) will be critical.

Utility regulation has historically focused on providing safe and reliable service at the lowest cost to consumers with relatively limited explicit consideration of environmental impacts. At the same time, state and federal environmental regulators have not historically considered the details of utility ratemaking and cost recovery when setting emission standards. More recently, cities have started to establish environment-focused regulations with limited coordination with other environmental or utility regulators, businesses, labor, or consumer groups. In addition, policies established within one city can affect customers across a wide geographic region that have not participated in the decision. Successful decarbonization that minimizes consumer cost impacts will require coordination between local, state, and federal regulators and legislators, and coordination between regulators and utilities. Regulators and legislators will need to ensure that policies to lower emissions and incentives to develop and implement new technologies and new approaches are sufficient to drive desired activity as reliably and cost-effectively as possible and without unintended consequences for customers.

A successful, reliable, cost-effective decarbonization program requires a cooperative, coordinated pathway across sectors, energy sources, and levels of government.

6 KEY TAKEAWAYS

Climate change is one of the defining challenges of our time. Addressing climate change will require fundamental changes in energy use throughout our economy. Gas utilities have an opportunity to help their customers and communities address these priorities. This report provides an in-depth assessment of several illustrative pathways that demonstrate the different kinds of emissions reduction opportunities available to gas utilities; the role of existing and emerging technologies; and other key considerations that will be essential in creating effective and equitable decarbonization initiatives. A variety of key takeaways stemming from this analysis are shown below.

1. Gas utilities and gas infrastructure can play crucial and enduring roles when building pathways to achieve a net-zero emissions future

Natural gas is a core component of the US energy system, and gas infrastructure delivers more energy in the U.S. than electrical infrastructure, particularly during times of peak energy usage. More than fifty percent of American households currently use natural gas as a heating fuel, and reliance on gas is even higher in many colder regions. The scale of the U.S. economy's dependence on gas infrastructure means that any realistic pathway to net-zero emissions by 2050 will need to address carbon and methane emissions associated with the use of natural gas. However, the current reliance on gas infrastructure also highlights the importance of utilizing the existing infrastructure to address climate change. Policymakers have long favored gas for its affordability, reliability, resiliency, and ability to store and transport large amounts of energy when cold outdoor temperatures drive large spikes in space heating energy use. Those benefits also offer important opportunities when considering pathways to a net-zero emissions future.

For this report, ICF worked with the AGA to develop a set of illustrative pathways combining different technologies and approaches to emission reductions with a focus on opportunities to reduce greenhouse gas emissions within gas utilities' purview, including operations and the direct use of natural gas by utility customers across residential, commercial, industrial, and transportation sectors. In these pathways, the U.S. economy is able to continue to rely on gas infrastructure to maintain reliability, meet peak energy demand, and realize the other benefits gas infrastructure brings to the overall energy system—while also reaching net-zero greenhouse gas emissions.

2. Using a range of different approaches and technologies, gas utilities can meet net-zero GHG emissions targets, and the appropriate mix of measures will vary by region and utility

This analysis demonstrates the significant greenhouse gas emissions reduction potential of a wide range of existing and emerging energy efficiency and gas equipment options. These include high-efficiency appliances, better insulation for buildings, smart thermostats, gas heat pumps, and hybrid gas-electric integrated heating systems, among others. The study also highlights the significant supply potential of different options for RNG, hydrogen blending, and opportunities to unlock greater renewable and low carbon gas supply through hydrogen by methanating it into a synthetic renewable natural gas. There are also options to rely more or less heavily on offsets or carbon sinks to reach net-zero.

The pathways discussed in this report combine a number of different measures and core strategies to reach net-zero emissions targets. As with any complex forward-looking projection incorporating a wide array of data inputs, these pathways depend on a range of assumptions. Because more emphasis was placed on developing pathways showcasing a diversity of options to meet 2050 targets—rather than optimizing all technologies included in a given scenario or trying to reach interim milestones— this study does not attempt to predict what is most likely to happen by 2050. The results are presented at the national level; further analysis including highly localized considerations (including costs) will be needed to study these and other pathways for a given region.

Particularly given the diverse array of measures available, the optimal pathways for a specific region and utility will vary based on highly localized factors, such as climate/temperatures, energy prices, the composition of the housing stock, and commercial and industrial base, as well as the capacity, age and GHG intensity of existing electricity generation, transmission, and distribution infrastructure. The other decarbonization pathways adopted in a given area, including for sectors outside the scope of this work (e.g., power generation and transportation) and the speed of change, will also impact the optimal pathway for a given region.

3. The ability of gas infrastructure to store and transport large amounts of energy to meet seasonal and peak day energy use represents an important and valuable resource that needs to be considered when building pathways to achieve net-zero greenhouse gas emissions goals

Many of the discussions and analyses looking at net-zero emissions targets begin from the assumption that mandated electrification of all fossil fuel uses, including all uses of natural gas, will be required, and that most, if not all, of the existing natural gas distribution infrastructure will need to be phased out. Stakeholders may not fully recognize the value of natural gas decarbonization strategies or the potential risks of a limited decarbonization approach that focuses exclusively on electrification of all sectors of the economy.

It's important to note that the peak space heating load currently served by natural gas is significantly larger than what the electrical system is designed for in most regions. This is largely because the existing gas energy storage and delivery infrastructure was primarily designed to reliably serve customers through spikes in consumption during cold winter periods, while the electric infrastructure was generally designed for lower levels of peak demand (largely driven by summer air conditioning loads). Over the last five years, the demand for natural gas during the coldest winter month has been about 58% higher than the demand for electricity during the peak summer month within the buildings sector, and about 84% higher than the demand for electricity for all end-uses.

Because of this, a large-scale shift to electric heating—even using highly-efficient technology such as air-source heat pumps—would likely drive significant increases in peak electric loads, shift the electric grid from summer peaking to winter peaking in many locations, and increase the challenges associated with decarbonizing electric generation using intermittent renewable sources. In contrast, leveraging both gas and electricity in decarbonization plans could help alleviate other challenges associated with an electrification-only approach. Planning for a net-zero future should not necessitate a choice between one energy system or another energy system (gas, electricity, or other forms)—making use of both systems for their relative strengths should allow for a lower-risk pathway to reducing emissions.

4. Continued utilization of gas infrastructure can increase the likelihood of successfully reaching net-zero targets while minimizing customer impacts

Any pathway to net-zero emissions will require transformative changes to multiple energy systems and the economy as a whole and will face a number of significant emergent challenges (both expected and unexpected). However, some decarbonization pathways are likely to be more feasible to implement, appealing to customers, and have a higher chance of success. All of the emissions reduction options need to be considered and, where viable, deployed in net-zero emissions pathways to maintain flexibility, decrease the chances of energy systems failing, maintain or increase existing public support for aggressive climate action, and increase the chances of reaching net-zero targets. Pre-selecting 'winning' technologies for 2050 or making decisions to shut down some energy systems that customers across all sectors currently rely on will reduce the role that innovation can play in supporting emissions reductions and may make it more difficult and expensive to achieve the net-zero emissions goals.

5. Large amounts of renewable and low-carbon electricity and gases, and negative emissions technologies, will be required to meet an economy-wide 2050 net-zero target

As in the power sector, rapid and widespread adoption of renewable, low-carbon, and negative emissions resources in the gas sector will be essential to decarbonizing the energy supply if the gas distribution system is to be part of the decarbonization solution. All pathways included in this study incorporate a significant expansion of renewable natural gas (RNG) and hydrogen consumption. RNG has a clear role in helping different sectors to decarbonize. Uncertainties remain regarding the pace of technology advancements, competition from other sectors for this renewable energy, and policy approaches that will impact how quickly production levels can be ramped up, costs, and what total volumes might be achievable. Nonetheless, given its large potential to significantly reduce emissions, efforts should be taken to support the development and deployment of RNG and hydrogen projects as these issues are being studied and addressed. In order for the economy to reach net-zero targets, there will likely be a use for all of the renewable gas that can be produced.

6. Gas utilities can achieve significant emission reductions by pursuing immediate actions like expanded energy efficiency, renewable fuels, and methane emissions mitigation

Regardless of the general approach to decarbonization, there are several immediate actions that will advance climate change objectives. Improvements in energy efficiency are often the lowest-cost approach to reducing emissions and can have a significant impact while also offering a range of benefits to customers (from reduced bills to increased comfort). Many of the energy efficiency measures that gas utilities can support, such as smart thermostats or building insulation retrofits, also promote customer choice since they can support decarbonization pathways using both electric and gas end uses. Any pathway to net-zero will also require significant increases in renewable and low carbon gas, and all of the production that can be brought online will likely be needed. Finally, more accurate quantification and reduction of methane leaks is also a key strategy approach to reducing GHG emissions. However, more precise and company-specific methane emissions factors will likely be needed to capture direct utility emissions more accurately and help utilities prioritize and track leak reductions going forward.

7. Supportive policy and regulatory approval will be essential for gas utilities to achieve net-zero emissions

Reaching net-zero emissions targets will require transformative changes to our energy systems and economy, and the analysis in this report lays out a series of illustrative pathways demonstrating the kinds of ways in which gas utilities can support this transition. However, gas utilities cannot implement many of these decarbonization pathways on their own. Gas utilities operate under strict regulations by state and federal regulators and must adhere to many rules and processes. There are set parameters on the rates they charge customers to recover costs for investments and operating expenses, including the gas supply acquisitions. Natural gas utility regulations have historically focused on providing safe, reliable, and affordable service to consumers. There would be benefits to integrating environmental considerations into gas utility regulatory constructs. Environmental and climate policy must be aligned with gas utility regulatory constructs for gas utilities to continue to invest in gas infrastructure while advancing cost-effective emissions reduction opportunities.

8. With increased RD&D and coordination with the electric sector, there are greater opportunities to unlock more decarbonization measures that leverage the gas system

The IEA stated in their Net Zero by 2050 report that by 2050, almost 50% of the reductions in CO_2 emissions must come from technologies that are "currently at the demonstration or prototype phase. Major innovation efforts must take place this decade to bring these new technologies to market in time."[123] The net-zero pathways in this study include a balance of existing technologies in the market today, early-stage commercial technologies that are just beginning to reach the market, and emerging technologies, at different stages of research, development, and demonstration (RD&D). RD&D funding offers a critical opportunity to support major new emissions reductions solutions, some of which are envisioned in this report, while others may not yet have been conceptualized. Given the scale of the challenge in reaching net-zero greenhouse gas emissions across the economy, and the inherent uncertainty in possible pathways to achieving net-zero emissions in other parts of the economy, companies and the government should continue to increase investment in gas system RD&D opportunities. Investments to unlock longer-term opportunities do not mean avoiding taking action now, particularly on immediate actions, but parallel efforts to develop new and improved solutions can help make achieving these targets more likely and cost-effective. While RD&D needs are by no means exclusive to gas technologies, there are a number of promising areas to support, including gas heat pumps, hydrogen blending, and thermal gasification.

There may also be opportunities to take a more collaborative approach to decarbonization across both the electricity and gas systems. The current natural gas and electric systems have evolved together to meet customer energy needs with a high degree of reliability, at a relatively low cost, by effectively leveraging the relative benefits of both energy systems. Responding to the need for deep greenhouse gas emissions reductions will create fundamental challenges to both systems, particularly due to the need to shift from conventional gas supply and power generation sources to emerging renewable and low-carbon power and gas sources. Supporting a system where gas and electric utilities can continue to work together to reduce emissions could help minimize negative customer impacts, maintain high reliability, and create opportunities for emerging technologies (such as power-to-gas and hydrogen) to support the needs of both systems, accelerate carbon reductions, and improve overall energy system resiliency. All options should be on the table to ensure a cost-effective, reliable, resilient, and equitable transition to a net-zero energy system, and gas and electric utilities both have roles to play to support this transition.

123 https://www.iea.org/reports/net-zero-by-2050

APPENDICES

A. DISTRIBUTED ENERGY RESOURCES POTENTIAL MODEL (DERPM) OVERVIEW

The demand side technical modeling for residential and commercial sectors was performed using ICF's Distributed Energy Resources Potential Model (DERPM). DERPM is a measure-based, bottom-up model built upon the best practice principles for potential modeling outlined by National Action Plan for Energy Efficiency (NAPEE) in their *Guide for Conducting Energy Efficiency Potential Studies*.[124] The model was designed to handle joint gas and electric energy efficiency, distributed energy resources, demand response (including load flexibility), and electrification; and it can be used to calculate technical, economic, and achievable potential estimates. DERPM has an Excel front end, with an "R" code back-end that allows the model to handle many permutations.

Distributed Energy Resources Potential Model (DERPM) is ICF's leading edge potential study model built on more than a decade's worth of ICF's experience performing potential studies. It offers a simple Excel-based front end and employs an open-source R script plug-in for all computationally intensive calculations.

DERPM was built to simultaneously (as needed) perform bottom-up potential studies for:

1. Joint Gas & Electric Energy Efficiency
2. Demand Response
3. Distributed Energy Resources
   (i.e., cogeneration, PV, behind-the-meter battery storage)
4. Electrification (G2E, EV, and Fuel Switching)

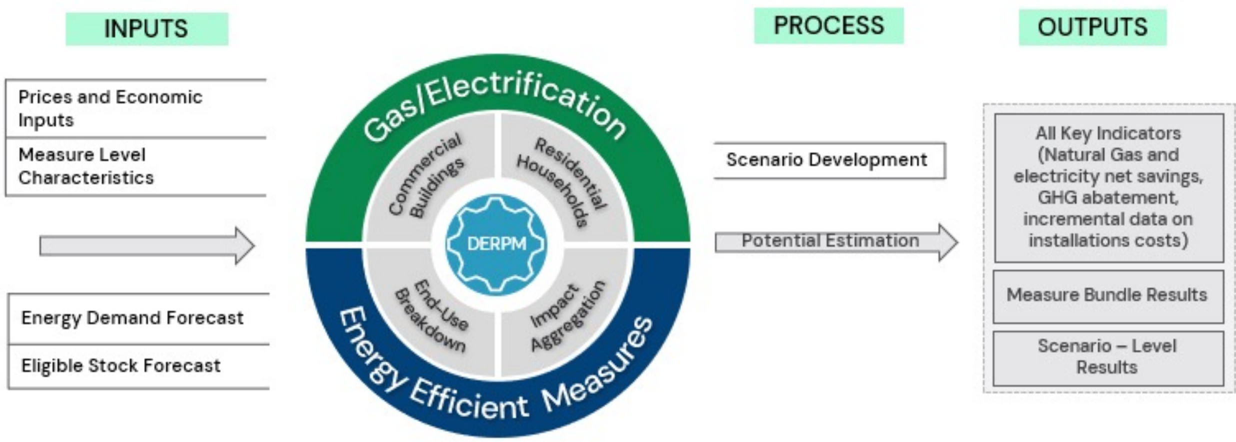
DERPM interfaces with DOE's Open Studio and EnergyPlus to develop accurate building load profiles. It was also built with enough computational power to run sophisticated optimization scripts and Monte Carlo risk analysis. DERPM outputs rich details in many flat files (CSV) that can be interpreted in Excel, Tableau, or PowerBI.

For this study, the technical modeling examined U.S. gas demand from residential and commercial customers by Census region over 30 years and explored energy savings strategies across the U.S. **Exhibit 46** illustrates the DERPM simplified version used to quantify carbon emissions reduction from the reference case of the four energy efficiency pathways scoped in this analysis and described in **Section 4.1.2**.

The four energy efficiency pathways differences are incorporated into the modeling throughout their technology focus and the velocity in their adoption rates. In total, a set of 35 technologies was considered in the analysis. Every decarbonization pathway was modeled separately, and depending on every approach, a subset of those technologies was flagged, or more weight was put on their rate of penetration curves (**Table 7** shows the list of measures/technologies included by pathway). The model results were obtained for every technology separately but grouped and presented in the body of this report into six categories to simplify the description of the outcomes: Dedicated hydrogen infrastructure, Efficient envelopes, Gas heat pumps, Selective electrification, Hybrid gas/electric heating, and Other energy efficiency measures—a detailed list of technologies by each subset of measures is presented in **Table 7**.

124 National Action Plan for Energy Efficiency (2007). *Guideline for Conducting Energy Efficiency Potential Studies*. https://www.epa.gov/sites/production/files/2015-08/documents/potential_guide_0.pdf

Exhibit 46 –
ICF's DERPM Model (Illustrated Here) was Established to Study Pathways Development



The model used information on applicable units, energy demand forecast, penetration rate curves, and gas savings curves to calculate each pathway's energy savings and carbon emission reductions. The definition of the main inputs is briefly explained below, and a data summary is presented in **Appendix B**.

- **Applicable Units:** This input information contains the baseline stock forecast for every measure and every year—**Table 9** and **Table 15** show the baseline stock forecast by Census region and vintage. For the residential sector, the data includes the breakdown of number of multifamily and single-family households by primary gas equipment end use, including space heating, space cooling, water heating, cooking, and other uses. For the commercial sector, information includes square footage forecast of gas customers split into four sub-sectors: institutional, offices, retail businesses, and other businesses. Baseline stock forecast assumes the same customer growth as AEO 2021, and calculation splits customers between existing buildings and new construction

- **Energy Use Intensity:** This input includes gas demand breakdown of residential and commercial sectors by sub-sector and end-use (**Table 10** and **Table 16**). As expected, most gas demand goes to space heating across all Census regions differing in the amount of fuel consumed per customer. For example, customers in the Northeast region consume more natural gas than those in the West region due to colder winters.

  Consumption per customer forecast assumes consumption per customer remains constant over the study period and also that new construction is expected to perform 20% more efficiently for space heating than existing buildings as a result of better envelope components and building HVAC components commercially available for new building designs

- **Penetration rate curves:** This user defined input includes the share of eligible stock expected to adopt each efficiency measure every year. These assumptions vary by each pathway and sector, as shown from **Table 11** to **Table 14** for residential and from **Table 17** to **Table 20** for the commercial sector

- **Gas savings rates:** This input specifies how measures' energy savings assumptions are divided between different end-uses (see **Table 8**)

DERPM takes the inputs described above and estimates potential savings from applying the efficient measures available for each sub-sector end-use. This quantifies how much energy and demand could be reduced, given the efficient technologies available. To compute total savings potential, the model runs all permutations combining savings per EE measure unit, expected measure penetration, and total number of measure units (or total eligible stock) by all adoption types (ROB, RET, and NC).[125]

In order to keep from overestimating potential estimation, DERPM accounts for the interactions between measure types. For instance, a building shell improvement measure will reduce the overall heating and cooling load of a building, which will impact the savings obtainable from the implementation of an efficient natural gas heat pump, and the savings available from a behavioral program. To account for these interactions, DERPM implemented a cascading approach, in which the savings from the first measure decrease the baseline end-use Energy Use Intensity for the next measure, and therefore, the savings opportunity for the next measure. Under this type of system, we assume an implementation hierarchy to allow for a straightforward cascade of impacts between measures. The cascading order of measures was provided as an input to the model; this means that a change in measures hierarchy interaction could result in different savings results for individual measures without changing overall demand reduction results.

Finally, DERPM generates outputs that contain MMBtu gas savings, and GHG annual incremental savings for each measure bundle. Those results were summarized and combined with the industrial sector analysis results and presented in **Section 4.2**.

125 Measures' adoption type definitions:

- **Time of Sale or Replace on Burnout (ROB)** which applies to those units installed for customers who would purchase a new product independently of an efficiency program, with the program only influencing the product's efficiency level
- **Retrofit (RET)** which applies to all existing buildings that would be influenced by programs aimed to convince customers to add efficiency measures
- **New Construction (NC)** applies to all new units installed every year that are part of efficiency measures included in design or building construction

B. DERPM INPUTS

Measures Assumptions

Table 7 – List of Measures by Subgroups

Measure Subgroup	Measure Name	Sector		Measure Type			Pathway			
		Residential	Commercial	New Construction	Retrofit	Time of Sale	1- Gas EE Focus	2- Gas-Electric Heating	3-Mixed Technology	4- Renewable and Low Carbon Gases
Dedicated Hydrogen Infrastructure	District Water Heating	✔	✔	✔	✔					✔
	Hydrogen Boiler	✔	✔	✔		✔				✔
	Hydrogen District Heating	✔	✔	✔	✔					✔
	Hydrogen Furnace/Boiler	✔	✔	✔		✔				✔
	Replacing Other Use (Incl. CHP) with Hydrogen		✔	✔		✔				✔
Efficient Envelope	Existing Building Retrofits – Building shell improvements	✔	✔		✔		✔	✔	✔	✔
	Existing Building Retrofits – Building shell Retrofit	✔	✔		✔		✔			
	New Construction: Aggressive Building Codes	✔	✔	✔			✔			
	New Construction: Best Conventional Technologies	✔	✔	✔			✔	✔	✔	✔
Gas Heat Pumps	Gas Heat Pump Water Heater	✔	✔	✔		✔	✔		✔	✔
	Gas Heat Pumps for Space Heating	✔	✔	✔		✔	✔		✔	✔
Hybrid Gas/ Electric Heating	Hybrid gas-electric (ASHP with gas backup)	✔	✔	✔		✔		✔	✔	
Other	Behavioral - Home Energy Reports	✔			✔		✔	✔	✔	✔
	Behavioral Measures		✔		✔		✔	✔	✔	✔
	Building Control System		✔	✔	✔		✔	✔	✔	✔
	Building re-comissioning and O&M measures		✔		✔		✔	✔	✔	✔
	Efficiency Improvements to Reduce Other Use (incl CHP)		✔	✔		✔	✔	✔	✔	✔
	Energy Saving Kits	✔	✔		✔		✔	✔	✔	✔
	EnergyStar Appliances	✔		✔		✔	✔	✔	✔	✔
	EnergyStar Cooking Appliances	✔	✔	✔		✔	✔	✔	✔	✔
	EnergyStar Dryer	✔		✔		✔	✔	✔	✔	✔
	EnergyStar Tank Water Heater	✔	✔	✔		✔	✔	✔	✔	✔
	High Efficiency Cooking Appliances	✔		✔		✔	✔	✔	✔	✔
	High Efficiency Gas Furnaces / boiler	✔	✔	✔		✔	✔	✔	✔	✔
	Higher Efficiency Gas Cooling		✔	✔		✔	✔	✔	✔	✔
	Low Flow Fixtures	✔	✔	✔			✔	✔	✔	✔
	Replacing Other Use (Incl. CHP) with Grid Electricity & Gas Boiler		✔	✔		✔		✔	✔	
	Smart Thermostat	✔		✔	✔		✔	✔	✔	✔
	Tankless Water Heaters	✔	✔	✔		✔	✔	✔	✔	✔
Selective Electrification	Electric Appliances	✔		✔		✔		✔	✔	
	Electric ASHP	✔	✔	✔		✔			✔	
	Electric Cooking Appliances	✔	✔	✔		✔		✔	✔	
	Electrified Cooling		✔	✔		✔		✔	✔	
	Electric Dryer	✔		✔		✔		✔	✔	
	Electric Heat Pump Water Heater	✔	✔	✔		✔		✔	✔	

Measures Assumptions

Table 8 – Measure Energy Savings

End Use	Measure	Vintage	Residential		Commercial			
			Multifamily	Single Family	Institutional	Office	Retail	Other
Clothes Drying	Electric Dryer	Existing Building	100%	100%	NA	NA	NA	NA
		New Construction	100%	100%	NA	NA	NA	NA
	EnergyStar Dryer	Existing Building	27%	27%	NA	NA	NA	NA
		New Construction	27%	27%	NA	NA	NA	NA
Cooking	Electric Cooking Appliances	Existing Building	100%	100%	100%	100%	100%	100%
		New Construction	100%	100%	100%	100%	100%	100%
	EnergyStar Cooking Appliances	Existing Building	23%	NA	5%	5%	5%	5%
		New Construction	23%	NA	5%	5%	5%	5%
	High Efficiency Cooking Appliances	Existing Building	NA	23%	NA	NA	NA	NA
		New Construction	NA	23%	NA	NA	NA	NA
Hot Water	Electric Heat Pump Water Heater	Existing Building	100%	100%	100%	100%	100%	100%
		New Construction	100%	100%	100%	100%	100%	100%
	Energy Saving Kits	Existing Building	15%	15%	20%	20%	20%	20%
	EnergyStar Tank Water Heater	Existing Building	19%	19%	6%	6%	6%	6%
		New Construction	19%	19%	5%	5%	5%	5%
	Gas Heat Pump Water Heater	Existing Building	51%	51%	32%	32%	32%	32%
		New Construction	51%	51%	31%	31%	31%	31%
	Hydrogen Boiler	Existing Building	100%	100%	100%	100%	100%	100%
		New Construction	100%	100%	100%	100%	100%	100%
	Hydrogen CHP Water Heating	Existing Building	100%	NA	100%	100%	100%	100%
		New Construction	100%	NA	100%	100%	100%	100%
	Hydrogen District Water Heating	Existing Building	100%	100%	100%	100%	100%	100%
		New Construction	100%	100%	100%	100%	100%	100%
	Hydrogen Micro-CHP Water Heating	Existing Building	NA	100%	NA	NA	NA	NA
		New Construction	NA	100%	NA	NA	NA	NA
	Low Flow Fixtures	New Construction	NA	15%	20%	20%	20%	20%
	Tankless Water Heaters	Existing Building	27%	27%	5%	5%	5%	5%
		New Construction	32%	27%	4%	4%	4%	4%
Other	Electric Appliances	Existing Building	100%	100%	NA	NA	NA	NA
		New Construction	100%	100%	NA	NA	NA	NA
	EnergyStar Appliances	Existing Building	8%	8%	NA	NA	NA	NA
		New Construction	8%	8%	NA	NA	NA	NA
	Efficiency Improvements to Reduce Other Use (incl CHP)	Existing Building	NA	NA	25%	25%	25%	25%
		New Construction	NA	NA	25%	25%	25%	25%
	Replacing Other Use (Incl. CHP) with Electric	Existing Building	NA	NA	100%	100%	100%	100%
		New Construction	NA	NA	100%	100%	100%	100%
Space Cooling	Electrified Cooling	Existing Building	NA	NA	100%	100%	100%	100%
		New Construction	NA	NA	100%	100%	100%	100%
	Higher Efficiency Gas Cooling	Existing Building	NA	NA	10%	10%	10%	10%
		New Construction	NA	NA	10%	10%	10%	10%
Space Heating	Behavioral - Home Energy Reports	Existing Building	2%	2%	NA	NA	NA	NA
	Electric ASHP	Existing Building	100%	100%	100%	100%	100%	100%
		New Construction	100%	100%	100%	100%	100%	100%
	Existing Building Retrofits: Building shell improvements	Existing Building	5%	15%	5%	5%	5%	5%
	Existing Building Retrofits: Building shell Retrofit	Existing Building	25%	30%	25%	25%	25%	25%
	Gas Heat Pumps for Space Heating	Existing Building	37%	41%	39%	39%	44%	44%
		New Construction	31%	36%	38%	38%	43%	43%
	High Efficiency Gas Furnaces / boiler	Existing Building	14%	14%	17%	17%	17%	17%
		New Construction	5%	5%	16%	16%	16%	16%
	Hybrid gas-electric (ASHP with gas backup)	Existing Building	75%	75%	75%	75%	75%	75%
		New Construction	75%	75%	75%	75%	75%	75%
	Hydrogen CHP	Existing Building	100%	NA	100%	100%	100%	100%
		New Construction	100%	NA	100%	100%	100%	100%
	Hydrogen District Heating	Existing Building	100%	100%	100%	100%	100%	100%
		New Construction	100%	100%	100%	100%	100%	100%
	Hydrogen Furnace/Boiler	Existing Building	100%	100%	100%	100%	100%	100%
		New Construction	100%	100%	100%	100%	100%	100%
	Hydrogen Micro-CHP	Existing Building	NA	100%	NA	NA	NA	NA
		New Construction	NA	100%	NA	NA	NA	NA
	New Construction: Aggressive Building Codes	New Construction	80%	80%	80%	80%	80%	80%
	New Construction: Best Conventional Technologies	New Construction	40%	40%	40%	40%	40%	40%
	Smart Thermostat	Existing Building	7%	7%	NA	NA	NA	NA
		New Construction	7%	7%	NA	NA	NA	NA
	Behavioral Measures	Existing Building	NA	NA	2%	2%	2%	2%
	Building Control System	Existing Building	NA	NA	5%	5%	5%	5%
		New Construction	NA	NA	5%	5%	5%	5%
	Building re-comissioning and O&M measures	Existing Building	NA	NA	10%	10%	10%	10%

Residential Sector Assumptions

Applicable Units

Table 9 – Residential Sector Equipment Stock by End-Use (million units)

Census Region	Sub-sector	End use	Existing Buildings			New Construction	
			2020	2050	2020-2050	2020	2050
Northeast	Multifamily	Space heating	4.8	3.8	-22%	-	2.6
		Water heater	4.5	3.5	-22%	-	2.3
		Cooking equipment	5.1	4.0	-22%	-	2.8
		Clothes dryers	0.5	0.4	-22%	-	0.4
		Other	0.7	0.6	-22%	-	0.4
	Single Family	Space heating	7.4	6.2	-16%	-	3.5
		Water heater	6.8	5.7	-16%	-	3.1
		Cooking equipment	6.7	5.6	-16%	-	3.3
		Clothes dryers	3.5	3.0	-16%	-	2.5
		Other	2.2	1.9	-16%	-	0.9
Midwest	Multifamily	Space heating	3.5	2.7	-22%	-	1.8
		Water heater	3.3	2.6	-22%	-	1.7
		Cooking equipment	1.8	1.4	-22%	-	1.0
		Clothes dryers	0.5	0.4	-22%	-	0.4
		Other	0.2	0.2	-22%	-	0.1
	Single Family	Space heating	16.6	13.9	-16%	-	7.8
		Water heater	13.7	11.5	-16%	-	6.2
		Cooking equipment	9.3	7.8	-16%	-	4.6
		Clothes dryers	6.3	5.3	-16%	-	4.6
		Other	2.6	2.2	-16%	-	1.0
South	Multifamily	Space heating	1.7	1.3	-22%	-	0.9
		Water heater	2.1	1.6	-22%	-	1.1
		Cooking equipment	1.6	1.2	-22%	-	0.9
		Clothes dryers	0.1	0.1	-22%	-	0.1
		Other	0.4	0.3	-22%	-	0.2
	Single Family	Space heating	12.9	10.8	-16%	-	5.9
		Water heater	11.7	9.8	-16%	-	5.3
		Cooking equipment	10.0	8.4	-16%	-	5.0
		Clothes dryers	2.4	2.0	-16%	-	1.7
		Other	4.0	3.3	-16%	-	1.5
West	Multifamily	Space heating	2.7	2.1	-22%	-	1.4
		Water heater	5.0	3.9	-22%	-	2.5
		Cooking equipment	2.8	2.2	-22%	-	1.5
		Clothes dryers	0.6	0.5	-22%	-	0.5
		Other	0.8	0.6	-22%	-	0.4
	Single Family	Space heating	12.2	10.2	-16%	-	5.7
		Water heater	12.9	10.9	-16%	-	5.9
		Cooking equipment	10.6	8.9	-16%	-	5.3
		Clothes dryers	5.3	4.5	-16%	-	3.8
		Other	3.9	3.3	-16%	-	1.5

Residential Sector Assumptions

Gas Use Intensity

Table 10 – Residential Sector
Annual Gas Demand by End-Use and Sub-sector (million Btu per household)

Vintage	Sub-sector	End use	Household End-Use Consumption			
			Northeast	Midwest	South	West
Existing Households	Multi-family	Space Heating	32.1	30.3	18.8	9.7
		Water Heating	17.9	14.7	13.0	10.3
		Cooking	1.2	1.1	1.2	3.8
		Clothes Dryers	0.8	0.5	1.1	3.2
		Other	28.7	2.1	20.3	25.8
	Single Family	Space Heating	91.1	80.9	49.7	44.8
		Water Heating	21.0	18.7	18.1	14.5
		Cooking	1.5	1.2	1.3	4.6
		Clothes Dryers	0.9	0.9	1.1	4.7
		Other	9.4	2.3	18.0	36.6
New Construction	Multi-family	Space Heating	25.7	24.3	15.0	7.7
		Water Heating	17.9	14.7	13.0	10.3
		Cooking	1.2	1.1	1.2	3.8
		Clothes Dryers	0.8	0.5	1.1	3.2
		Other	28.7	2.1	20.3	25.8
	Single Family	Space Heating	72.9	64.7	39.8	35.8
		Water Heating	21.0	18.7	18.1	14.5
		Cooking	1.5	1.2	1.3	4.6
		Clothes Dryers	0.9	0.9	1.1	4.7
		Other	9.4	2.3	18.0	36.6

Residential Sector Assumptions

Penetration rate curves

Table 11 – Residential Sector Penetration Rate Curve – Pathway 1 Gas Energy Efficiency Focus (percentage of active units)

Measure Name	Sub-sector	Delivery Type	2020	2025	2030	2035	2040	2045	2050
Behavioral - Home Energy Reports	Single Family	Retrofit	0%	60%	80%	80%	80%	80%	80%
	Multifamily	Retrofit	0%	60%	60%	60%	60%	60%	60%
Energy Saving Kits	Single Family	Retrofit	0%	2%	2%	2%	2%	2%	2%
	Multifamily	Retrofit	0%	2%	2%	2%	2%	2%	2%
EnergyStar Appliances	Single Family	Time of Sale	0%	30%	80%	80%	80%	80%	80%
		New Construction	0%	30%	80%	80%	80%	80%	80%
	Multifamily	Time of Sale	0%	30%	80%	80%	80%	80%	80%
		New Construction	0%	30%	80%	80%	80%	80%	80%
EnergyStar Cooking Appliances	Multifamily	Time of Sale	0%	50%	80%	80%	80%	80%	80%
		New Construction	0%	50%	80%	80%	80%	80%	80%
EnergyStar Dryer	Single Family	Time of Sale	0%	30%	80%	80%	80%	80%	80%
		New Construction	0%	30%	80%	80%	80%	80%	80%
	Multifamily	Time of Sale	0%	30%	80%	80%	80%	80%	80%
		New Construction	0%	30%	80%	80%	80%	80%	80%
EnergyStar Tank Water Heater	Single Family	Time of Sale	0%	40%	85%	60%	15%	15%	15%
		New Construction	0%	40%	80%	55%	10%	10%	10%
	Multifamily	Time of Sale	0%	40%	85%	73%	55%	55%	55%
		New Construction	0%	40%	80%	55%	10%	10%	10%
Existing Building Retrofits - Building shell improvements	Single Family	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Multifamily	Retrofit	0%	1%	1%	1%	1%	1%	1%
Existing Building Retrofits - Building shell Retrofit	Single Family	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Multifamily	Retrofit	0%	1%	1%	1%	1%	1%	1%
Gas Heat Pump Water Heater	Single Family	Time of Sale	0%	1%	10%	35%	80%	80%	80%
		New Construction	0%	1%	10%	35%	80%	80%	80%
	Multifamily	Time of Sale	0%	1%	10%	22%	40%	40%	40%
		New Construction	0%	1%	10%	35%	80%	80%	80%
Gas Heat Pumps for Space Heating	Single Family	Time of Sale	0%	1%	10%	35%	75%	75%	75%
		New Construction	0%	1%	10%	35%	80%	80%	80%
	Multifamily	Time of Sale	0%	1%	10%	22%	40%	40%	40%
		New Construction	0%	1%	10%	35%	80%	80%	80%
High Efficiency Cooking Appliances	Single Family	Time of Sale	0%	50%	80%	80%	80%	80%	80%
		New Construction	0%	50%	80%	80%	80%	80%	80%
High Efficiency Gas Furnaces / boiler	Single Family	Time of Sale	0%	50%	90%	65%	25%	25%	25%
		New Construction	0%	50%	90%	65%	20%	20%	20%
	Multifamily	Time of Sale	0%	50%	90%	78%	60%	60%	60%
		New Construction	0%	50%	90%	65%	20%	20%	20%
Low Flow Fixtures	Single Family	New Construction	0%	30%	80%	80%	80%	80%	80%
	Multifamily	New Construction	0%	30%	80%	80%	80%	80%	80%
New Construction: BestConventional Technologies	Single Family	New Construction	0%	5%	95%	50%	50%	50%	50%
	Multifamily	New Construction	0%	5%	95%	50%	50%	50%	50%
New Construction: Aggressive Building Codes	Single Family	New Construction	0%	0%	5%	50%	50%	50%	50%
	Multifamily	New Construction	0%	0%	5%	50%	50%	50%	50%
Smart Thermostat	Single Family	Retrofit	0%	2%	2%	3%	3%	3%	3%
		New Construction	0%	25%	50%	85%	85%	85%	85%
	Multifamily	Retrofit	0%	2%	2%	2%	2%	2%	2%
		New Construction	0%	25%	50%	85%	85%	85%	85%
Tankless Water Heaters	Single Family	Time of Sale	0%	5%	5%	5%	5%	5%	5%
		New Construction	0%	5%	10%	10%	10%	10%	10%
	Multifamily	Time of Sale	0%	5%	5%	5%	5%	5%	5%
		New Construction	0%	5%	10%	10%	10%	10%	10%

Residential Sector Assumptions

Penetration rate curves (con't)

Table 12 – Residential Sector Penetration Rate Curve – Pathway 2 Hybrid Gas - Electric Heating Focus (percentage of active units)

Measure Name	Sub-sector	Delivery Type	2020	2025	2030	2035	2040	2045	2050
Behavioral - Home Energy Reports	Single Family	Retrofit	0%	60%	80%	80%	80%	80%	80%
	Multifamily	Retrofit	0%	60%	60%	60%	60%	60%	60%
Electric Appliances	Single Family	Time of Sale	0%	50%	50%	50%	50%	50%	50%
		New Construction	0%	50%	50%	50%	50%	50%	50%
	Multifamily	Time of Sale	0%	50%	50%	50%	50%	50%	50%
		New Construction	0%	50%	50%	50%	50%	50%	50%
Electric Cooking Appliances	Single Family	Time of Sale	0%	50%	50%	50%	50%	50%	50%
		New Construction	0%	50%	50%	50%	50%	50%	50%
	Multifamily	Time of Sale	0%	50%	50%	50%	50%	50%	50%
		New Construction	0%	50%	50%	50%	50%	50%	50%
Electric Dryer	Single Family	Time of Sale	0%	50%	50%	50%	50%	50%	50%
		New Construction	0%	50%	50%	50%	50%	50%	50%
	Multifamily	Time of Sale	0%	50%	50%	50%	50%	50%	50%
		New Construction	0%	50%	50%	50%	50%	50%	50%
Electric Heat Pump Water Heater	Single Family	Time of Sale	0%	1%	15%	40%	40%	40%	40%
		New Construction	0%	1%	15%	40%	40%	40%	40%
	Multifamily	Time of Sale	0%	1%	15%	40%	40%	40%	40%
		New Construction	0%	1%	15%	40%	40%	40%	40%
Energy Saving Kits	Single Family	Retrofit	0%	2%	2%	2%	2%	2%	2%
	Multifamily	Retrofit	0%	2%	2%	2%	2%	2%	2%
EnergyStar Appliances	Single Family	Time of Sale	0%	20%	40%	40%	40%	40%	40%
		New Construction	0%	50%	50%	50%	50%	50%	50%
	Multifamily	Time of Sale	0%	20%	40%	40%	40%	40%	40%
		New Construction	0%	50%	50%	50%	50%	50%	50%
EnergyStar Cooking Appliances	Multifamily	Time of Sale	0%	20%	40%	40%	40%	40%	40%
	Multifamily	New Construction	0%	20%	40%	40%	40%	40%	40%
EnergyStar Dryer	Single Family	Time of Sale	0%	20%	40%	40%	40%	40%	40%
		New Construction	0%	50%	50%	50%	50%	50%	50%
	Multifamily	Time of Sale	0%	20%	40%	40%	40%	40%	40%
		New Construction	0%	50%	50%	50%	50%	50%	50%
EnergyStar Tank Water Heater	Single Family	Time of Sale	0%	40%	75%	45%	45%	45%	45%
		New Construction	0%	40%	70%	45%	45%	45%	45%
	Multifamily	Time of Sale	0%	40%	75%	45%	45%	45%	45%
		New Construction	0%	40%	70%	45%	45%	45%	45%
Existing Building Retrofits - Building shell improvements	Single Family	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Multifamily	Retrofit	0%	1%	1%	1%	1%	1%	1%
High Efficiency Cooking Appliances	Single Family	Time of Sale	0%	20%	40%	40%	40%	40%	40%
		New Construction	0%	20%	40%	40%	40%	40%	40%
High Efficiency Gas Furnaces / boiler	Single Family	Time of Sale	0%	50%	65%	20%	20%	20%	20%
		New Construction	0%	50%	20%	20%	20%	20%	20%
	Multifamily	Time of Sale	0%	50%	90%	78%	60%	60%	60%
		New Construction	0%	50%	20%	20%	20%	20%	20%
Hybrid gas-electric (ASHP with gas backup)	Single Family	Time of Sale	0%	10%	35%	80%	80%	80%	80%
		New Construction	0%	15%	80%	80%	80%	80%	80%
	Multifamily	Time of Sale	0%	1%	10%	22%	40%	40%	40%
		New Construction	0%	15%	80%	80%	80%	80%	80%
Low Flow Fixtures	Single Family	New Construction	0%	30%	80%	80%	80%	80%	80%
	Multifamily	New Construction	0%	30%	80%	80%	80%	80%	80%
New Construction: Best Conventional Technologies	Single Family	New Construction	0%	3%	20%	100%	100%	100%	100%
	Multifamily	New Construction	0%	3%	20%	100%	100%	100%	100%
Smart Thermostat	Single Family	Retrofit	0%	2%	2%	3%	3%	3%	3%
		New Construction	0%	25%	50%	85%	85%	85%	85%
	Multifamily	Retrofit	0%	2%	2%	2%	2%	2%	2%
		New Construction	0%	25%	50%	85%	85%	85%	85%
Tankless Water Heaters	Single Family	Time of Sale	0%	5%	10%	15%	15%	15%	15%
		New Construction	0%	10%	15%	15%	15%	15%	15%
	Multifamily	Time of Sale	0%	5%	10%	15%	15%	15%	15%
		New Construction	0%	10%	15%	15%	15%	15%	15%

Residential Sector Assumptions

Penetration rate curves (con't)

Table 13 – Residential Sector Penetration Rate Curve – Pathway 3 Mixed Technology Approach (percentage of active units)

Measure Name	Sub-sector	Delivery Type	2020	2025	2030	2035	2040	2045	2050
Behavioral - Home Energy Reports	Single Family	Retrofit	0%	60%	80%	80%	80%	80%	80%
	Multifamily	Retrofit	0%	60%	60%	60%	60%	60%	60%
Electric Appliances	Single Family	Time of Sale	0%	50%	50%	50%	50%	50%	50%
		New Construction	0%	50%	50%	50%	50%	50%	50%
	Multifamily	Time of Sale	0%	50%	50%	50%	50%	50%	50%
		New Construction	0%	50%	50%	50%	50%	50%	50%
Electric ASHP	Single Family	Time of Sale	0%	0%	8%	10%	10%	10%	10%
		New Construction	0%	1%	15%	50%	50%	50%	50%
	Multifamily	Time of Sale	0%	0%	5%	5%	5%	5%	5%
		New Construction	0%	1%	15%	50%	50%	50%	50%
Electric Cooking Appliances	Single Family	Time of Sale	0%	50%	50%	50%	50%	50%	50%
		New Construction	0%	50%	50%	50%	50%	50%	50%
	Multifamily	Time of Sale	0%	50%	50%	50%	50%	50%	50%
		New Construction	0%	50%	50%	50%	50%	50%	50%
Electric Dryer	Single Family	Time of Sale	0%	50%	50%	50%	50%	50%	50%
		New Construction	0%	50%	50%	50%	50%	50%	50%
	Multifamily	Time of Sale	0%	50%	50%	50%	50%	50%	50%
		New Construction	0%	50%	50%	50%	50%	50%	50%
Electric Heat Pump Water Heater	Single Family	Time of Sale	0%	1%	15%	40%	40%	40%	40%
		New Construction	0%	1%	15%	40%	40%	40%	40%
	Multifamily	Time of Sale	0%	1%	15%	40%	40%	40%	40%
		New Construction	0%	1%	15%	40%	40%	40%	40%
Energy Saving Kits	Single Family	Retrofit	0%	2%	2%	2%	2%	2%	2%
	Multifamily	Retrofit	0%	2%	2%	2%	2%	2%	2%
EnergyStar Appliances	Single Family	Time of Sale	0%	20%	40%	40%	40%	40%	40%
		New Construction	0%	50%	50%	50%	50%	50%	50%
	Multifamily	Time of Sale	0%	20%	40%	40%	40%	40%	40%
		New Construction	0%	50%	50%	50%	50%	50%	50%
EnergyStar Cooking Appliances	Multifamily	Time of Sale	0%	20%	40%	40%	40%	40%	40%
		New Construction	0%	20%	40%	40%	40%	40%	40%
EnergyStar Dryer	Single Family	Time of Sale	0%	20%	40%	40%	40%	40%	40%
		New Construction	0%	50%	50%	50%	50%	50%	50%
	Multifamily	Time of Sale	0%	20%	40%	40%	40%	40%	40%
		New Construction	0%	50%	50%	50%	50%	50%	50%
EnergyStar Tank Water Heater	Single Family	Time of Sale	0%	40%	70%	30%	20%	20%	20%
		New Construction	0%	40%	65%	30%	20%	20%	20%
	Multifamily	Time of Sale	0%	40%	70%	30%	20%	20%	20%
		New Construction	0%	40%	65%	30%	20%	20%	20%
Existing Building Retrofits - Building shell improvements	Single Family	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Multifamily	Retrofit	0%	1%	1%	1%	1%	1%	1%
Gas Heat Pump Water Heater	Single Family	Time of Sale	0%	1%	5%	15%	25%	25%	25%
		New Construction	0%	1%	5%	15%	25%	25%	25%
	Multifamily	Time of Sale	0%	1%	5%	15%	25%	25%	25%
		New Construction	0%	1%	5%	15%	25%	25%	25%
Gas Heat Pumps for Space Heating	Single Family	Time of Sale	0%	0%	8%	30%	40%	40%	40%
		New Construction	0%	0%	8%	15%	15%	15%	15%
	Multifamily	Time of Sale	0%	0%	3%	20%	20%	20%	20%
		New Construction	0%	0%	8%	15%	15%	15%	15%
High Efficiency Cooking Appliances	Single Family	Time of Sale	0%	20%	40%	40%	40%	40%	40%
		New Construction	0%	20%	40%	40%	40%	40%	40%
High Efficiency Gas Furnaces boiler	Single Family	Time of Sale	0%	50%	45%	20%	10%	10%	10%
		New Construction	0%	50%	63%	20%	20%	20%	20%
	Multifamily	Time of Sale	0%	50%	78%	55%	55%	55%	55%
		New Construction	0%	50%	63%	20%	20%	20%	20%
Hybrid gas-electric (ASHP with gas backup)	Single Family	Time of Sale	0%	8%	40%	40%	40%	40%	40%
		New Construction	0%	1%	15%	15%	15%	15%	15%
	Multifamily	Time of Sale	0%	1%	15%	20%	20%	20%	20%
		New Construction	0%	1%	15%	15%	15%	15%	15%
Low Flow Fixtures	Single Family	New Construction	0%	30%	80%	80%	80%	80%	80%
	Multifamily	New Construction	0%	30%	80%	80%	80%	80%	80%
New Construction: Best Conventional Technologies	Single Family	New Construction	0%	3%	20%	100%	100%	100%	100%
	Multifamily	New Construction	0%	3%	20%	100%	100%	100%	100%
Smart Thermostat	Single Family	Retrofit	0%	2%	2%	3%	3%	3%	3%
		New Construction	0%	25%	50%	85%	85%	85%	85%
	Multifamily	Retrofit	0%	2%	2%	2%	2%	2%	2%
		New Construction	0%	25%	50%	85%	85%	85%	85%
Tankless Water Heaters	Single Family	Time of Sale	0%	5%	10%	15%	15%	15%	15%
		New Construction	0%	10%	15%	15%	15%	15%	15%
	Multifamily	Time of Sale	0%	5%	10%	15%	15%	15%	15%
		New Construction	0%	10%	15%	15%	15%	15%	15%

Residential Sector Assumptions

Penetration rate curves (con't)

Table 14 – Residential Sector Penetration Rate Curve – Pathway 4 Renewable and Low Carbon Gas Focus (percentage of active units)

Measure Name	Sub-sector	Delivery Type	2020	2025	2030	2035	2040	2045	2050
Behavioral - Home Energy Reports	Single Family	Retrofit	0%	60%	80%	80%	80%	80%	80%
	Multifamily	Retrofit	0%	60%	60%	60%	60%	60%	60%
Energy Saving Kits	Single Family	Retrofit	0%	2%	2%	2%	2%	2%	2%
	Multifamily	Retrofit	0%	2%	2%	2%	2%	2%	2%
EnergyStar Appliances	Single Family	Time of Sale	0%	30%	80%	80%	80%	80%	80%
		New Construction	0%	30%	80%	80%	80%	80%	80%
	Multifamily	Time of Sale	0%	30%	80%	80%	80%	80%	80%
		New Construction	0%	30%	80%	80%	80%	80%	80%
EnergyStar Cooking Appliances	Multifamily	Time of Sale	0%	50%	80%	80%	80%	80%	80%
		New Construction	0%	50%	80%	80%	80%	80%	80%
EnergyStar Dryer	Single Family	Time of Sale	0%	30%	80%	80%	80%	80%	80%
		New Construction	0%	30%	80%	80%	80%	80%	80%
	Multifamily	Time of Sale	0%	30%	80%	80%	80%	80%	80%
		New Construction	0%	30%	80%	80%	80%	80%	80%
EnergyStar Tank Water Heater	Single Family	Time of Sale	0%	40%	85%	75%	70%	70%	65%
		New Construction	0%	40%	75%	70%	70%	65%	60%
	Multifamily	Time of Sale	0%	40%	85%	75%	70%	70%	65%
		New Construction	0%	40%	75%	70%	69%	60%	50%
Existing Building Retrofits - Building shell improvements	Single Family	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Multifamily	Retrofit	0%	1%	1%	1%	1%	1%	1%
Gas Heat Pump Water Heater	Single Family	Time of Sale	0%	0%	5%	10%	15%	15%	15%
		New Construction	0%	0%	10%	15%	15%	15%	15%
	Multifamily	Time of Sale	0%	0%	5%	10%	15%	15%	15%
		New Construction	0%	0%	10%	15%	15%	15%	15%
Gas Heat Pumps for Space Heating	Single Family	Time of Sale	0%	0%	8%	10%	10%	10%	10%
		New Construction	0%	0%	8%	15%	15%	15%	15%
	Multifamily	Time of Sale	0%	0%	8%	10%	10%	10%	10%
		New Construction	0%	0%	8%	10%	10%	10%	10%
High Efficiency Cooking Appliances	Single Family	Time of Sale	0%	50%	80%	80%	80%	80%	80%
		New Construction	0%	50%	80%	80%	80%	80%	80%
High Efficiency Gas Furnaces/ boiler	Single Family	Time of Sale	0%	50%	93%	90%	90%	90%	85%
		New Construction	0%	50%	93%	85%	85%	80%	75%
	Multifamily	Time of Sale	0%	50%	93%	90%	90%	90%	85%
		New Construction	0%	50%	93%	90%	90%	85%	80%
Hydrogen Boiler	Single Family	Time of Sale	0%	0%	0%	0%	0%	1%	5%
		New Construction	0%	0%	0%	0%	1%	5%	10%
	Multifamily	Time of Sale	0%	0%	0%	0%	0%	1%	5%
		New Construction	0%	0%	0%	0%	1%	5%	10%
Hydrogen District Heating	Multifamily	Retrofit	0%	0%	0%	0%	0%	0%	0%
		New Construction	0%	0%	0%	0%	1%	5%	10%
Hydrogen District Water Heating	Multifamily	Retrofit	0%	0%	0%	0%	0%	0%	0%
		New Construction	0%	0%	0%	0%	1%	5%	10%
Hydrogen Furnace/Boiler	Single Family	Time of Sale	0%	0%	0%	0%	0%	1%	5%
		New Construction	0%	0%	0%	0%	1%	5%	10%
	Multifamily	Time of Sale	0%	0%	0%	0%	0%	1%	5%
		New Construction	0%	0%	0%	0%	1%	5%	10%
Low Flow Fixtures	Single Family	New Construction	0%	30%	80%	80%	80%	80%	80%
	Multifamily	New Construction	0%	30%	80%	80%	80%	80%	80%
New Construction: Best Conventional Technologies	Single Family	New Construction	0%	3%	20%	100%	100%	100%	100%
	Multifamily	New Construction	0%	3%	20%	100%	100%	100%	100%
Smart Thermostat	Single Family	Retrofit	0%	2%	2%	3%	3%	3%	3%
		New Construction	0%	25%	50%	85%	85%	85%	85%
	Multifamily	Retrofit	0%	2%	2%	2%	2%	2%	2%
		New Construction	0%	25%	50%	85%	85%	85%	85%
Tankless Water Heaters	Single Family	Time of Sale	0%	5%	10%	15%	15%	15%	15%
		New Construction	0%	10%	15%	15%	15%	15%	15%
	Multifamily	Time of Sale	0%	5%	10%	15%	15%	15%	15%
		New Construction	0%	10%	15%	15%	15%	15%	15%

Commercial Sector Assumptions

Applicable Units

Table 15 – Applicable Units for Commercial Sector are the Forecast of Square Footage by Sub-Sector (billion square feet)

Census Region	Sub-sector	Existing Buildings			New Construction	
		2020	2050	2020-2050	2020	2050
Northeast	Institutional	2.4	1.7	-30%	-	1.5
	Office	3.6	2.6	-30%	-	2.3
	Other	3.0	2.1	-30%	-	1.9
	Retail	3.6	2.5	-30%	-	2.3
Midwest	Institutional	3.6	2.5	-30%	-	2.2
	Office	3.2	2.2	-30%	-	2.0
	Other	4.2	3.0	-30%	-	2.6
	Retail	6.1	4.3	-30%	-	3.8
South	Institutional	5.1	3.6	-30%	-	3.2
	Office	3.3	2.3	-30%	-	2.1
	Other	6.0	4.2	-30%	-	3.7
	Retail	8.2	5.8	-30%	-	5.1
West	Institutional	2.1	1.5	-30%	-	1.3
	Office	2.9	2.1	-30%	-	1.8
	Other	3.8	2.7	-30%	-	2.4
	Retail	5.6	3.9	-30%	-	3.5

Commercial Sector Assumptions

Gas Use Intensity

Table 16 – Commercial Sector
Annual Gas Demand by End-Use and Sub-sector (thousand Btu per square foot)

Vintage	Sub-Sector	End Use	End-Use Consumption			
			Northeast	Midwest	South	West
Existing Buildings	Retail	Space Heating	37.1	39.0	13.8	14.9
		Space Cooling	0.1	0.01	-	-
		Water Heating	17.7	15.8	18.8	14.8
		Cooking	4.7	2.5	5.3	5.5
		Other	9.3	6.0	4.2	4.5
	Office	Space Heating	28.1	42.6	14.4	19.4
		Space Cooling	0.3	0.6	0.3	0.0
		Water Heating	8.2	1.0	1.6	1.2
		Cooking	3.5	3.6	1.3	2.1
		Other	10.9	10.8	4.6	2.7
	Institutional	Space Heating	53.3	50.4	16.2	25.2
		Space Cooling	4.6	0.6	0.7	2.2
		Water Heating	7.7	4.0	4.5	4.8
		Cooking	6.2	3.7	7.2	9.9
		Other	14.9	10.9	5.0	9.6
	Other	Space Heating	33.5	41.7	14.4	14.8
		Space Cooling	0.2	0.2	0.1	-
		Water Heating	5.9	4.1	4.7	12.0
		Cooking	6.4	4.1	7.1	10.1
		Other	7.9	9.6	13.0	17.5
New Construction	Retail	Space Heating	29.7	31.2	11.0	11.9
		Space Cooling	0.1	0.01	-	-
		Water Heating	17.7	15.8	18.8	14.8
		Cooking	4.7	2.5	5.3	5.5
		Other	9.3	6.0	4.2	4.5
	Office	Space Heating	22.5	34.1	11.6	15.5
		Space Cooling	0.3	0.6	0.3	0.0
		Water Heating	8.2	1.0	1.6	1.2
		Cooking	3.5	3.6	1.3	2.1
		Other	10.9	10.8	4.6	2.7
	Institutional	Space Heating	42.6	40.3	12.9	20.2
		Space Cooling	4.6	0.6	0.7	2.2
		Water Heating	7.7	4.0	4.5	4.8
		Cooking	6.2	3.7	7.2	9.9
		Other	14.9	10.9	5.0	9.6
	Other	Space Heating	26.8	33.4	11.6	11.8
		Space Cooling	0.2	0.2	0.1	-
		Water Heating	5.9	4.1	4.7	12.0
		Cooking	6.4	4.1	7.1	10.1
		Other	7.9	9.6	13.0	17.5

Commercial Sector Assumptions

Penetration Rate Curves

Table 17 – Commercial Sector Penetration Rate Curve – Pathway 1 Gas Energy Efficiency Focus (percentage of active units)

Measure Name	Sub-sector	Delivery Type	2020	2025	2030	2035	2040	2045	2050
Behavioral Measures	Retail	Retrofit	0%	20%	20%	20%	20%	20%	20%
	Office	Retrofit	0%	20%	20%	20%	20%	20%	20%
	Institutional	Retrofit	0%	20%	20%	20%	20%	20%	20%
	Other	Retrofit	0%	20%	20%	20%	20%	20%	20%
Building Control System	Retail	Retrofit	0%	2%	2%	2%	2%	2%	2%
		New Construction	0%	25%	50%	85%	85%	85%	85%
	Office	Retrofit	0%	2%	2%	2%	2%	2%	2%
		New Construction	0%	25%	50%	85%	85%	85%	85%
	Institutional	Retrofit	0%	2%	2%	2%	2%	2%	2%
		New Construction	0%	25%	50%	85%	85%	85%	85%
	Other	Retrofit	0%	2%	2%	2%	2%	2%	2%
		New Construction	0%	25%	50%	85%	85%	85%	85%
Building re-comissioning and O&M measures	Retail	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Office	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Institutional	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Other	Retrofit	0%	1%	1%	1%	1%	1%	1%
Efficiency Improvements to Reduce Other Use (incl CHP)	Retail	Time of Sale	0%	5%	20%	70%	80%	80%	80%
	Retail	New Construction	0%	30%	80%	80%	80%	80%	80%
	Office	Time of Sale	0%	5%	20%	70%	80%	80%	80%
	Office	New Construction	0%	30%	80%	80%	80%	80%	80%
	Institutional	Time of Sale	0%	5%	20%	70%	80%	80%	80%
	Institutional	New Construction	0%	30%	80%	80%	80%	80%	80%
	Other	Time of Sale	0%	5%	20%	70%	80%	80%	80%
	Other	New Construction	0%	30%	80%	80%	80%	80%	80%
Energy Saving Kits	Retail	Retrofit	0%	2%	2%	2%	2%	2%	2%
	Office	Retrofit	0%	2%	2%	2%	2%	2%	2%
	Institutional	Retrofit	0%	2%	2%	2%	2%	2%	2%
	Other	Retrofit	0%	2%	2%	2%	2%	2%	2%
EnergyStar Cooking Appliances	Retail	Time of Sale	0%	50%	80%	80%	80%	80%	80%
		New Construction	0%	50%	80%	80%	80%	80%	80%
	Office	Time of Sale	0%	50%	80%	80%	80%	80%	80%
		New Construction	0%	50%	80%	80%	80%	80%	80%
	Institutional	Time of Sale	0%	50%	80%	80%	80%	80%	80%
		New Construction	0%	50%	80%	80%	80%	80%	80%
	Other	Time of Sale	0%	50%	80%	80%	80%	80%	80%
		New Construction	0%	50%	80%	80%	80%	80%	80%
EnergyStar Tank Water Heater	Retail	Time of Sale	0%	40%	80%	55%	10%	10%	10%
		New Construction	0%	40%	85%	60%	15%	15%	15%
	Office	Time of Sale	0%	40%	85%	73%	55%	55%	55%
		New Construction	0%	40%	85%	60%	15%	15%	15%
	Institutional	Time of Sale	0%	40%	85%	73%	55%	55%	55%
		New Construction	0%	40%	85%	60%	15%	15%	15%
	Other	Time of Sale	0%	40%	80%	55%	10%	10%	10%
		New Construction	0%	40%	80%	55%	10%	10%	10%
Existing Building Retrofits - Building shell improvements	Retail	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Office	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Institutional	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Other	Retrofit	0%	1%	1%	1%	1%	1%	1%
Existing Building Retrofits - Building shell Retrofit	Retail	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Office	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Institutional	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Other	Retrofit	0%	1%	1%	1%	1%	1%	1%

Commercial Sector Assumptions

Penetration Rate Curves (con't)

Table 17 (con't) – Commercial Sector Penetration Rate Curve – Pathway 1 Gas Energy Efficiency Focus (percentage of active units)

Measure Name	Sub-sector	Delivery Type	2020	2025	2030	2035	2040	2045	2050
Gas Heat Pump Water Heater	Retail	Time of Sale	0%	1%	10%	35%	80%	80%	80%
		New Construction	0%	1%	10%	35%	80%	80%	80%
	Office	Time of Sale	0%	1%	10%	22%	40%	40%	40%
		New Construction	0%	1%	10%	35%	80%	80%	80%
	Institutional	Time of Sale	0%	1%	10%	22%	40%	40%	40%
		New Construction	0%	1%	10%	35%	80%	80%	80%
	Other	Time of Sale	0%	1%	10%	35%	80%	80%	80%
		New Construction	0%	1%	10%	35%	80%	80%	80%
Gas Heat Pumps for Space Heating	Retail	Time of Sale	0%	1%	10%	35%	75%	75%	75%
		New Construction	0%	1%	10%	35%	80%	80%	80%
	Office	Time of Sale	0%	1%	10%	22%	40%	40%	40%
		New Construction	0%	1%	10%	35%	80%	80%	80%
	Institutional	Time of Sale	0%	1%	10%	22%	40%	40%	40%
		New Construction	0%	1%	10%	35%	80%	80%	80%
	Other	Time of Sale	0%	1%	10%	35%	80%	80%	80%
		New Construction	0%	1%	10%	35%	80%	80%	80%
High Efficiency Gas Furnaces / boiler	Retail	Time of Sale	0%	50%	90%	65%	25%	25%	25%
		New Construction	0%	50%	90%	65%	20%	20%	20%
	Office	Time of Sale	0%	50%	90%	78%	60%	60%	60%
		New Construction	0%	50%	90%	65%	20%	20%	20%
	Institutional	Time of Sale	0%	50%	90%	78%	60%	60%	60%
		New Construction	0%	50%	90%	65%	20%	20%	20%
	Other	Time of Sale	0%	50%	90%	65%	20%	20%	20%
		New Construction	0%	50%	90%	65%	20%	20%	20%
Higher Efficiency Gas Cooling	Retail	Time of Sale	0%	30%	80%	80%	80%	80%	80%
		New Construction	0%	30%	80%	80%	80%	80%	80%
	Office	Time of Sale	0%	30%	80%	80%	80%	80%	80%
		New Construction	0%	30%	80%	80%	80%	80%	80%
	Institutional	Time of Sale	0%	30%	80%	80%	80%	80%	80%
		New Construction	0%	30%	80%	80%	80%	80%	80%
	Other	Time of Sale	0%	30%	80%	80%	80%	80%	80%
		New Construction	0%	30%	80%	80%	80%	80%	80%
Low Flow Fixtures	Retail	New Construction	0%	30%	80%	80%	80%	80%	80%
	Office	New Construction	0%	30%	80%	80%	80%	80%	80%
	Institutional	New Construction	0%	30%	80%	80%	80%	80%	80%
	Other	New Construction	0%	30%	80%	80%	80%	80%	80%
New Construction - Best Conventional Technologies	Retail	New Construction	0%	5%	95%	50%	50%	50%	50%
	Office	New Construction	0%	5%	95%	50%	25%	25%	25%
	Institutional	New Construction	0%	5%	95%	50%	25%	25%	25%
	Other	New Construction	0%	5%	95%	50%	50%	50%	50%
New Construction - Aggressive Building Codes)	Retail	New Construction	0%	0%	5%	50%	50%	50%	50%
	Office	New Construction	0%	0%	5%	50%	75%	75%	75%
	Institutional	New Construction	0%	0%	5%	50%	75%	75%	75%
	Other	New Construction	0%	0%	5%	50%	50%	50%	50%
Tankless Water Heaters	Retail	Time of Sale	0%	5%	10%	10%	10%	10%	10%
		New Construction	0%	5%	5%	5%	5%	5%	5%
	Office	Time of Sale	0%	5%	5%	5%	5%	5%	5%
		New Construction	0%	5%	5%	5%	5%	5%	5%
	Institutional	Time of Sale	0%	5%	5%	5%	5%	5%	5%
		New Construction	0%	5%	5%	5%	5%	5%	5%
	Other	Time of Sale	0%	5%	10%	10%	10%	10%	10%
		New Construction	0%	5%	10%	10%	10%	10%	10%

Commercial Sector Assumptions

Penetration Rate Curves (Con't)

Table 18 – Commercial Sector Penetration Rate Curve – Pathway 2 Hybrid Gas - Electric Heating Focus (percentage of active units)

Measure Name	Sub-sector	Delivery Type	2020	2025	2030	2035	2040	2045	2050
Behavioral Measures	Retail	Retrofit	0%	20%	20%	20%	20%	20%	20%
	Office	Retrofit	0%	20%	20%	20%	20%	20%	20%
	Institutional	Retrofit	0%	20%	20%	20%	20%	20%	20%
	Other	Retrofit	0%	20%	20%	20%	20%	20%	20%
Building Control System	Retail	Retrofit	0%	2%	2%	2%	2%	2%	2%
		New Construction	0%	25%	50%	85%	85%	85%	85%
	Office	Retrofit	0%	2%	2%	2%	2%	2%	2%
		New Construction	0%	25%	50%	85%	85%	85%	85%
	Institutional	Retrofit	0%	2%	2%	2%	2%	2%	2%
		New Construction	0%	25%	50%	85%	85%	85%	85%
	Other	Retrofit	0%	2%	2%	2%	2%	2%	2%
		New Construction	0%	25%	50%	85%	85%	85%	85%
Building re-comissioning and O&M measures	Retail	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Office	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Institutional	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Other	Retrofit	0%	1%	1%	1%	1%	1%	1%
Efficiency Improvements to Reduce Other Use (incl CHP)	Retail	Time of Sale	0%	15%	50%	50%	50%	50%	50%
		New Construction	0%	15%	50%	50%	50%	50%	50%
	Office	Time of Sale	0%	15%	50%	50%	50%	50%	50%
		New Construction	0%	15%	50%	50%	50%	50%	50%
	Institutional	Time of Sale	0%	15%	50%	50%	50%	50%	50%
		New Construction	0%	15%	50%	50%	50%	50%	50%
	Other	Time of Sale	0%	15%	50%	50%	50%	50%	50%
		New Construction	0%	15%	50%	50%	50%	50%	50%
Electric Cooking Appliances	Retail	Time of Sale	0%	50%	50%	50%	50%	50%	50%
		New Construction	0%	50%	50%	50%	50%	50%	50%
	Office	Time of Sale	0%	50%	50%	50%	50%	50%	50%
		New Construction	0%	50%	50%	50%	50%	50%	50%
	Institutional	Time of Sale	0%	50%	50%	50%	50%	50%	50%
		New Construction	0%	50%	50%	50%	50%	50%	50%
	Other	Time of Sale	0%	50%	50%	50%	50%	50%	50%
		New Construction	0%	50%	50%	50%	50%	50%	50%
Electrified Cooling	Retail	Time of Sale	0%	50%	50%	50%	50%	50%	50%
		New Construction	0%	50%	50%	50%	50%	50%	50%
	Office	Time of Sale	0%	50%	50%	50%	50%	50%	50%
		New Construction	0%	50%	50%	50%	50%	50%	50%
	Institutional	Time of Sale	0%	50%	50%	50%	50%	50%	50%
		New Construction	0%	50%	50%	50%	50%	50%	50%
	Other	Time of Sale	0%	50%	50%	50%	50%	50%	50%
		New Construction	0%	50%	50%	50%	50%	50%	50%
Electric Heat Pump Water Heater	Retail	Time of Sale	0%	1%	15%	40%	40%	40%	40%
		New Construction	0%	1%	15%	40%	40%	40%	40%
	Office	Time of Sale	0%	1%	15%	40%	40%	40%	40%
		New Construction	0%	1%	15%	40%	40%	40%	40%
	Institutional	Time of Sale	0%	1%	15%	40%	40%	40%	40%
		New Construction	0%	1%	15%	40%	40%	40%	40%
	Other	Time of Sale	0%	1%	15%	40%	40%	40%	40%
		New Construction	0%	1%	15%	40%	40%	40%	40%
Energy Saving Kits	Retail	Retrofit	0%	2%	2%	2%	2%	2%	2%
	Office	Retrofit	0%	2%	2%	2%	2%	2%	2%
	Institutional	Retrofit	0%	2%	2%	2%	2%	2%	2%
	Other	Retrofit	0%	2%	2%	2%	2%	2%	2%
EnergyStar Cooking Appliances	Retail	Time of Sale	0%	20%	40%	40%	40%	40%	40%
		New Construction	0%	20%	40%	40%	40%	40%	40%
	Office	Time of Sale	0%	20%	40%	40%	40%	40%	40%
		New Construction	0%	20%	40%	40%	40%	40%	40%
	Institutional	Time of Sale	0%	20%	40%	40%	40%	40%	40%
		New Construction	0%	20%	40%	40%	40%	40%	40%
	Other	Time of Sale	0%	20%	40%	40%	40%	40%	40%
		New Construction	0%	20%	40%	40%	40%	40%	40%

Commercial Sector Assumptions

Penetration Rate Curves (Con't)

Table 18 (Con't) – Commercial Sector Penetration Rate Curve – Pathway 2 Hybrid Gas - Electric Heating Focus (percentage of active units)

Measure Name	Sub-sector	Delivery Type	2020	2025	2030	2035	2040	2045	2050
EnergyStar Tank Water Heater	Retail	Time of Sale	0%	40%	75%	45%	45%	45%	45%
		New Construction	0%	40%	70%	45%	45%	45%	45%
	Office	Time of Sale	0%	40%	75%	45%	45%	45%	45%
		New Construction	0%	40%	70%	45%	45%	45%	45%
	Institutional	Time of Sale	0%	40%	75%	45%	45%	45%	45%
		New Construction	0%	40%	70%	45%	45%	45%	45%
	Other	Time of Sale	0%	40%	75%	45%	45%	45%	45%
		New Construction	0%	40%	70%	45%	45%	45%	45%
Existing Building Retrofits - Building shell improvements	Retail	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Office	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Institutional	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Other	Retrofit	0%	1%	1%	1%	1%	1%	1%
High Efficiency Gas Furnaces / boiler	Retail	Time of Sale	0%	50%	65%	20%	20%	20%	20%
		New Construction	0%	50%	20%	20%	20%	20%	20%
	Office	Time of Sale	0%	50%	90%	78%	60%	60%	60%
		New Construction	0%	50%	20%	20%	20%	20%	20%
	Institutional	Time of Sale	0%	50%	90%	78%	60%	60%	60%
		New Construction	0%	50%	20%	20%	20%	20%	20%
	Other	Time of Sale	0%	50%	65%	20%	20%	20%	20%
		New Construction	0%	50%	20%	20%	20%	20%	20%
Higher Efficiency Gas Cooling	Retail	Time of Sale	0%	20%	40%	40%	40%	40%	40%
		New Construction	0%	50%	50%	50%	50%	50%	50%
	Office	Time of Sale	0%	20%	40%	40%	40%	40%	40%
		New Construction	0%	50%	50%	50%	50%	50%	50%
	Institutional	Time of Sale	0%	20%	40%	40%	40%	40%	40%
		New Construction	0%	50%	50%	50%	50%	50%	50%
	Other	Time of Sale	0%	20%	40%	40%	40%	40%	40%
		New Construction	0%	50%	50%	50%	50%	50%	50%
Hybrid gas-electric (ASHP with gas backup)	Retail	Time of Sale	0%	10%	35%	80%	80%	80%	80%
		New Construction	0%	15%	80%	80%	80%	80%	80%
	Office	Time of Sale	0%	1%	10%	22%	40%	40%	40%
		New Construction	0%	15%	80%	80%	80%	80%	80%
	Institutional	Time of Sale	0%	1%	10%	22%	40%	40%	40%
		New Construction	0%	15%	80%	80%	80%	80%	80%
	Other	Time of Sale	0%	10%	35%	80%	80%	80%	80%
		New Construction	0%	15%	80%	80%	80%	80%	80%
Low Flow Fixtures	Retail	New Construction	0%	30%	80%	80%	80%	80%	80%
	Office	New Construction	0%	30%	80%	80%	80%	80%	80%
	Institutional	New Construction	0%	30%	80%	80%	80%	80%	80%
	Other	New Construction	0%	30%	80%	80%	80%	80%	80%
New Construction - Best Conventional Technologies	Retail	New Construction	0%	3%	20%	100%	100%	100%	100%
	Office	New Construction	0%	3%	20%	100%	100%	100%	100%
	Institutional	New Construction	0%	3%	20%	100%	100%	100%	100%
	Other	New Construction	0%	3%	20%	100%	100%	100%	100%
Replacing Other Use (Incl. CHP) with Electric	Retail	Time of Sale	0%	15%	50%	50%	50%	50%	50%
		New Construction	0%	15%	50%	50%	50%	50%	50%
	Office	Time of Sale	0%	15%	50%	50%	50%	50%	50%
		New Construction	0%	15%	50%	50%	50%	50%	50%
	Institutional	Time of Sale	0%	15%	50%	50%	50%	50%	50%
		New Construction	0%	15%	50%	50%	50%	50%	50%
	Other	Time of Sale	0%	15%	50%	50%	50%	50%	50%
		New Construction	0%	15%	50%	50%	50%	50%	50%
Tankless Water Heaters	Retail	Time of Sale	0%	5%	10%	15%	15%	15%	15%
		New Construction	0%	10%	15%	15%	15%	15%	15%
	Office	Time of Sale	0%	5%	10%	15%	15%	15%	15%
		New Construction	0%	10%	15%	15%	15%	15%	15%
	Institutional	Time of Sale	0%	5%	10%	15%	15%	15%	15%
		New Construction	0%	10%	15%	15%	15%	15%	15%
	Other	Time of Sale	0%	5%	10%	15%	15%	15%	15%
		New Construction	0%	10%	15%	15%	15%	15%	15%

Commercial Sector Assumptions

Penetration Rate Curves (Con't)

Table 19 – Commercial Sector Penetration Rate Curve – Pathway 3 Mixed Technology Approach (percentage of active units)

Measure Name	Sub-sector	Delivery Type	2020	2025	2030	2035	2040	2045	2050
Behavioral Measures	Retail	Retrofit	0%	20%	20%	20%	20%	20%	20%
	Office	Retrofit	0%	20%	20%	20%	20%	20%	20%
	Institutional	Retrofit	0%	20%	20%	20%	20%	20%	20%
	Other	Retrofit	0%	20%	20%	20%	20%	20%	20%
Building Control System	Retail	Retrofit	0%	2%	2%	2%	2%	2%	2%
		New Construction	0%	25%	50%	85%	85%	85%	85%
	Office	Retrofit	0%	2%	2%	2%	2%	2%	2%
		New Construction	0%	25%	50%	85%	85%	85%	85%
	Institutional	Retrofit	0%	2%	2%	2%	2%	2%	2%
		New Construction	0%	25%	50%	85%	85%	85%	85%
	Other	Retrofit	0%	2%	2%	2%	2%	2%	2%
		New Construction	0%	25%	50%	85%	85%	85%	85%
Building re-comissioning and O&M measures	Retail	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Office	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Institutional	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Other	Retrofit	0%	1%	1%	1%	1%	1%	1%
Efficiency Improvements to Reduce Other Use (incl CHP)	Retail	Time of Sale	0%	15%	50%	50%	50%	50%	50%
		New Construction	0%	15%	50%	50%	50%	50%	50%
	Office	Time of Sale	0%	15%	50%	50%	50%	50%	50%
		New Construction	0%	15%	50%	50%	50%	50%	50%
	Institutional	Time of Sale	0%	15%	50%	50%	50%	50%	50%
		New Construction	0%	15%	50%	50%	50%	50%	50%
	Other	Time of Sale	0%	15%	50%	50%	50%	50%	50%
		New Construction	0%	15%	50%	50%	50%	50%	50%
Electric ASHP	Retail	Time of Sale	0%	0%	8%	10%	10%	10%	10%
		New Construction	0%	1%	15%	50%	50%	50%	50%
	Office	Time of Sale	0%	0%	5%	5%	5%	5%	5%
		New Construction	0%	1%	15%	50%	50%	50%	50%
	Institutional	Time of Sale	0%	0%	5%	5%	5%	5%	5%
		New Construction	0%	1%	15%	50%	50%	50%	50%
	Other	Time of Sale	0%	0%	8%	10%	10%	10%	10%
		New Construction	0%	1%	15%	50%	50%	50%	50%
Electric Cooking Appliances	Retail	Time of Sale	0%	50%	50%	50%	50%	50%	50%
		New Construction	0%	50%	50%	50%	50%	50%	50%
	Office	Time of Sale	0%	50%	50%	50%	50%	50%	50%
		New Construction	0%	50%	50%	50%	50%	50%	50%
	Institutional	Time of Sale	0%	50%	50%	50%	50%	50%	50%
		New Construction	0%	50%	50%	50%	50%	50%	50%
	Other	Time of Sale	0%	50%	50%	50%	50%	50%	50%
		New Construction	0%	50%	50%	50%	50%	50%	50%
Electrified Cooling	Retail	Time of Sale	0%	50%	50%	50%	50%	50%	50%
		New Construction	0%	50%	50%	50%	50%	50%	50%
	Office	Time of Sale	0%	50%	50%	50%	50%	50%	50%
		New Construction	0%	50%	50%	50%	50%	50%	50%
	Institutional	Time of Sale	0%	50%	50%	50%	50%	50%	50%
		New Construction	0%	50%	50%	50%	50%	50%	50%
	Other	Time of Sale	0%	50%	50%	50%	50%	50%	50%
		New Construction	0%	50%	50%	50%	50%	50%	50%
Electric Heat Pump Water Heater	Retail	Time of Sale	0%	1%	15%	40%	40%	40%	40%
		New Construction	0%	1%	15%	40%	40%	40%	40%
	Office	Time of Sale	0%	1%	15%	40%	40%	40%	40%
		New Construction	0%	1%	15%	40%	40%	40%	40%
	Institutional	Time of Sale	0%	1%	15%	40%	40%	40%	40%
		New Construction	0%	1%	15%	40%	40%	40%	40%
	Other	Time of Sale	0%	1%	15%	40%	40%	40%	40%
		New Construction	0%	1%	15%	40%	40%	40%	40%

Commercial Sector Assumptions

Penetration Rate Curves (Con't)

Table 19 (Con't) – Commercial Sector Penetration Rate Curve – Pathway 3 Mixed Technology Approach (percentage of active units)

Measure Name	Sub-sector	Delivery Type	2020	2025	2030	2035	2040	2045	2050
Energy Saving Kits	Retail	Retrofit	0%	2%	2%	2%	2%	2%	2%
	Office	Retrofit	0%	2%	2%	2%	2%	2%	2%
	Institutional	Retrofit	0%	2%	2%	2%	2%	2%	2%
	Other	Retrofit	0%	2%	2%	2%	2%	2%	2%
EnergyStar Cooking Appliances	Retail	Time of Sale	0%	20%	40%	40%	40%	40%	40%
		New Construction	0%	20%	40%	40%	40%	40%	40%
	Office	Time of Sale	0%	20%	40%	40%	40%	40%	40%
		New Construction	0%	20%	40%	40%	40%	40%	40%
	Institutional	Time of Sale	0%	20%	40%	40%	40%	40%	40%
		New Construction	0%	20%	40%	40%	40%	40%	40%
	Other	Time of Sale	0%	20%	40%	40%	40%	40%	40%
		New Construction	0%	20%	40%	40%	40%	40%	40%
EnergyStar Tank Water Heater	Retail	Time of Sale	0%	40%	75%	40%	30%	30%	30%
		New Construction	0%	40%	75%	40%	30%	30%	30%
	Office	Time of Sale	0%	40%	75%	40%	30%	30%	30%
		New Construction	0%	40%	75%	40%	30%	30%	30%
	Institutional	Time of Sale	0%	40%	75%	40%	30%	30%	30%
		New Construction	0%	40%	75%	40%	30%	30%	30%
	Other	Time of Sale	0%	40%	75%	40%	30%	30%	30%
		New Construction	0%	40%	75%	40%	30%	30%	30%
Existing Building Retrofits - Building shell improvements	Retail	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Office	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Institutional	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Other	Retrofit	0%	1%	1%	1%	1%	1%	1%
Gas Heat Pump Water Heater	Retail	Time of Sale	0%	1%	5%	15%	25%	25%	25%
		New Construction	0%	1%	5%	15%	25%	25%	25%
	Office	Time of Sale	0%	1%	5%	15%	25%	25%	25%
		New Construction	0%	1%	5%	15%	25%	25%	25%
	Institutional	Time of Sale	0%	1%	5%	15%	25%	25%	25%
		New Construction	0%	1%	5%	15%	25%	25%	25%
	Other	Time of Sale	0%	1%	5%	15%	25%	25%	25%
		New Construction	0%	1%	5%	15%	25%	25%	25%
Gas Heat Pumps for Space Heating	Retail	Time of Sale	0%	0%	8%	30%	40%	40%	40%
		New Construction	0%	0%	8%	15%	15%	15%	15%
	Office	Time of Sale	0%	0%	3%	20%	20%	20%	20%
		New Construction	0%	0%	8%	15%	15%	15%	15%
	Institutional	Time of Sale	0%	0%	3%	20%	20%	20%	20%
		New Construction	0%	0%	8%	15%	15%	15%	15%
	Other	Time of Sale	0%	0%	8%	30%	40%	40%	40%
		New Construction	0%	0%	8%	15%	15%	15%	15%
High Efficiency Gas Furnaces / boiler	Retail	Time of Sale	0%	50%	45%	20%	10%	10%	10%
		New Construction	0%	50%	63%	20%	20%	20%	20%
	Office	Time of Sale	0%	50%	78%	55%	55%	55%	55%
		New Construction	0%	50%	63%	20%	20%	20%	20%
	Institutional	Time of Sale	0%	50%	78%	55%	55%	55%	55%
		New Construction	0%	50%	63%	20%	20%	20%	20%
	Other	Time of Sale	0%	50%	45%	20%	10%	10%	10%
		New Construction	0%	50%	63%	20%	20%	20%	20%
Higher Efficiency Gas Cooling	Retail	Time of Sale	0%	20%	40%	40%	40%	40%	40%
		New Construction	0%	50%	50%	50%	50%	50%	50%
	Office	Time of Sale	0%	20%	40%	40%	40%	40%	40%
		New Construction	0%	50%	50%	50%	50%	50%	50%
	Institutional	Time of Sale	0%	20%	40%	40%	40%	40%	40%
		New Construction	0%	50%	50%	50%	50%	50%	50%
	Other	Time of Sale	0%	20%	40%	40%	40%	40%	40%
		New Construction	0%	50%	50%	50%	50%	50%	50%

Commercial Sector Assumptions

Penetration Rate Curves (Con't)

Table 19 (Con't) – Commercial Sector Penetration Rate Curve – Pathway 3 Mixed Technology Approach (percentage of active units)

Measure Name	Sub-sector	Delivery Type	2020	2025	2030	2035	2040	2045	2050
Hybrid gas-electric (ASHP with gas backup)	Retail	Time of Sale	0%	8%	40%	40%	40%	40%	40%
		New Construction	0%	1%	15%	15%	15%	15%	15%
	Office	Time of Sale	0%	1%	15%	20%	20%	20%	20%
		New Construction	0%	1%	15%	15%	15%	15%	15%
	Institutional	Time of Sale	0%	1%	15%	20%	20%	20%	20%
		New Construction	0%	1%	15%	15%	15%	15%	15%
	Other	Time of Sale	0%	8%	40%	40%	40%	40%	40%
		New Construction	0%	1%	15%	15%	15%	15%	15%
Low Flow Fixtures	Retail	New Construction	0%	30%	80%	80%	80%	80%	80%
	Office	New Construction	0%	30%	80%	80%	80%	80%	80%
	Institutional	New Construction	0%	30%	80%	80%	80%	80%	80%
	Other	New Construction	0%	30%	80%	80%	80%	80%	80%
New Construction - Best Conventional Technologies	Retail	New Construction	0%	3%	20%	100%	100%	100%	100%
	Office	New Construction	0%	3%	20%	100%	100%	100%	100%
	Institutional	New Construction	0%	3%	20%	100%	100%	100%	100%
	Other	New Construction	0%	3%	20%	100%	100%	100%	100%
Replacing Other Use (Incl. CHP) with Electric	Retail	Time of Sale	0%	15%	50%	50%	50%	50%	50%
		New Construction	0%	15%	50%	50%	50%	50%	50%
	Office	Time of Sale	0%	15%	50%	50%	50%	50%	50%
		New Construction	0%	15%	50%	50%	50%	50%	50%
	Institutional	Time of Sale	0%	15%	50%	50%	50%	50%	50%
		New Construction	0%	15%	50%	50%	50%	50%	50%
	Other	Time of Sale	0%	15%	50%	50%	50%	50%	50%
		New Construction	0%	15%	50%	50%	50%	50%	50%
Tankless Water Heaters	Retail	Time of Sale	0%	5%	5%	5%	5%	5%	5%
		New Construction	0%	5%	5%	5%	5%	5%	5%
	Office	Time of Sale	0%	5%	5%	5%	5%	5%	5%
		New Construction	0%	5%	5%	5%	5%	5%	5%
	Institutional	Time of Sale	0%	5%	5%	5%	5%	5%	5%
		New Construction	0%	5%	5%	5%	5%	5%	5%
	Other	Time of Sale	0%	5%	5%	5%	5%	5%	5%
		New Construction	0%	5%	5%	5%	5%	5%	5%

Commercial Sector Assumptions

Penetration Rate Curves (Con't)

Table 20 – Commercial Sector Penetration Rate Curve – Pathway 4 Renewable and Low Carbon Gas Focus (percentage of active units)

Measure Name	Sub-sector	Delivery Type	2020	2025	2030	2035	2040	2045	2050
Behavioral Measures	Retail	Retrofit	0%	20%	20%	20%	20%	20%	20%
	Office	Retrofit	0%	20%	20%	20%	20%	20%	20%
	Institutional	Retrofit	0%	20%	20%	20%	20%	20%	20%
	Other	Retrofit	0%	20%	20%	20%	20%	20%	20%
Building Control System	Retail	Retrofit	0%	2%	2%	2%	2%	2%	2%
		New Construction	0%	25%	50%	85%	85%	85%	85%
	Office	Retrofit	0%	2%	2%	2%	2%	2%	2%
		New Construction	0%	25%	50%	85%	85%	85%	85%
	Institutional	Retrofit	0%	2%	2%	2%	2%	2%	2%
		New Construction	0%	25%	50%	85%	85%	85%	85%
	Other	Retrofit	0%	2%	2%	2%	2%	2%	2%
		New Construction	0%	25%	50%	85%	85%	85%	85%
Building re-comissioning and O&M measures	Retail	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Office	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Institutional	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Other	Retrofit	0%	1%	1%	1%	1%	1%	1%
Efficiency Improvements to Reduce Other Use (incl CHP)	Retail	Time of Sale	0%	5%	20%	70%	80%	80%	80%
		New Construction	0%	30%	80%	80%	80%	80%	80%
	Office	Time of Sale	0%	5%	20%	70%	80%	80%	80%
		New Construction	0%	30%	80%	80%	80%	80%	80%
	Institutional	Time of Sale	0%	5%	20%	70%	75%	75%	75%
		New Construction	0%	30%	80%	80%	80%	80%	80%
	Other	Time of Sale	0%	5%	20%	70%	75%	75%	75%
		New Construction	0%	30%	80%	80%	80%	80%	80%
Energy Saving Kits	Retail	Retrofit	0%	2%	2%	2%	2%	2%	2%
	Office	Retrofit	0%	2%	2%	2%	2%	2%	2%
	Institutional	Retrofit	0%	2%	2%	2%	2%	2%	2%
	Other	Retrofit	0%	2%	2%	2%	2%	2%	2%
EnergyStar Cooking Appliances	Retail	Time of Sale	0%	50%	80%	80%	80%	80%	80%
		New Construction	0%	50%	80%	80%	80%	80%	80%
	Office	Time of Sale	0%	50%	80%	80%	80%	80%	80%
		New Construction	0%	50%	80%	80%	80%	80%	80%
	Institutional	Time of Sale	0%	50%	80%	80%	80%	80%	80%
		New Construction	0%	50%	80%	80%	80%	80%	80%
	Other	Time of Sale	0%	50%	80%	80%	80%	80%	80%
		New Construction	0%	50%	80%	80%	80%	80%	80%
EnergyStar Tank Water Heater	Retail	Time of Sale	0%	40%	85%	75%	70%	70%	65%
		New Construction	0%	40%	75%	70%	69%	60%	50%
	Office	Time of Sale	0%	40%	85%	75%	70%	70%	65%
		New Construction	0%	40%	75%	70%	69%	60%	50%
	Institutional	Time of Sale	0%	40%	85%	75%	70%	70%	65%
		New Construction	0%	40%	75%	70%	69%	60%	50%
	Other	Time of Sale	0%	40%	85%	75%	70%	70%	65%
		New Construction	0%	40%	75%	70%	69%	60%	50%
Existing Building Retrofits - Building shell improvements	Retail	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Office	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Institutional	Retrofit	0%	1%	1%	1%	1%	1%	1%
	Other	Retrofit	0%	1%	1%	1%	1%	1%	1%
Gas Heat Pump Water Heater	Retail	Time of Sale	0%	0%	5%	10%	15%	15%	15%
		New Construction	0%	0%	10%	15%	15%	15%	15%
	Office	Time of Sale	0%	0%	5%	10%	15%	15%	15%
		New Construction	0%	0%	10%	15%	15%	15%	15%
	Institutional	Time of Sale	0%	0%	5%	10%	15%	15%	15%
		New Construction	0%	0%	10%	15%	15%	15%	15%
	Other	Time of Sale	0%	0%	5%	10%	15%	15%	15%
		New Construction	0%	0%	10%	15%	15%	15%	15%

Commercial Sector Assumptions

Penetration Rate Curves (Con't)

Table 20 (Con't) – Commercial Sector Penetration Rate Curve – Pathway 4 Renewable and Low Carbon Gas Focus (percentage of active units)

Measure Name	Sub-sector	Delivery Type	2020	2025	2030	2035	2040	2045	2050
Gas Heat Pumps for Space Heating	Retail	Time of Sale	0%	0%	5%	10%	15%	15%	15%
		New Construction	0%	0%	8%	10%	10%	10%	10%
	Office	Time of Sale	0%	0%	5%	5%	5%	5%	5%
		New Construction	0%	0%	8%	10%	10%	10%	10%
	Institutional	Time of Sale	0%	0%	5%	10%	15%	15%	15%
		New Construction	0%	0%	8%	10%	10%	10%	10%
	Other	Time of Sale	0%	0%	5%	10%	15%	15%	15%
		New Construction	0%	0%	8%	10%	10%	10%	10%
High Efficiency Gas Furnaces / boiler	Retail	Time of Sale	0%	50%	95%	90%	85%	85%	80%
		New Construction	0%	50%	93%	90%	90%	85%	80%
	Office	Time of Sale	0%	50%	95%	90%	90%	90%	85%
		New Construction	0%	50%	93%	90%	90%	85%	80%
	Institutional	Time of Sale	0%	50%	95%	90%	85%	85%	80%
		New Construction	0%	50%	93%	90%	90%	85%	80%
	Other	Time of Sale	0%	50%	95%	90%	85%	85%	80%
		New Construction	0%	50%	93%	90%	90%	85%	80%
Higher Efficiency Gas Cooling	Retail	Time of Sale	0%	30%	80%	80%	80%	80%	80%
		New Construction	0%	30%	80%	80%	80%	80%	80%
	Office	Time of Sale	0%	30%	80%	80%	80%	80%	80%
		New Construction	0%	30%	80%	80%	80%	80%	80%
	Institutional	Time of Sale	0%	30%	80%	80%	80%	80%	80%
		New Construction	0%	30%	80%	80%	80%	80%	80%
	Other	Time of Sale	0%	30%	80%	80%	80%	80%	80%
		New Construction	0%	30%	80%	80%	80%	80%	80%
Hydrogen Boiler	Retail	Time of Sale	0%	0%	0%	0%	0%	1%	5%
		New Construction	0%	0%	0%	0%	1%	5%	10%
	Office	Time of Sale	0%	0%	0%	0%	0%	1%	5%
		New Construction	0%	0%	0%	0%	1%	5%	10%
	Institutional	Time of Sale	0%	0%	0%	0%	0%	1%	5%
		New Construction	0%	0%	0%	0%	1%	5%	10%
	Other	Time of Sale	0%	0%	0%	0%	0%	1%	5%
		New Construction	0%	0%	0%	0%	1%	5%	10%
Hydrogen District Heating	Retail	Retrofit	0%	0%	0%	0%	0%	0%	0%
		New Construction	0%	0%	0%	0%	1%	5%	10%
	Office	Retrofit	0%	0%	0%	0%	0%	0%	0%
		New Construction	0%	0%	0%	0%	1%	5%	10%
	Institutional	Retrofit	0%	0%	0%	0%	0%	0%	0%
		New Construction	0%	0%	0%	0%	1%	5%	10%
	Other	Retrofit	0%	0%	0%	0%	0%	0%	0%
		New Construction	0%	0%	0%	0%	1%	5%	10%
Hydrogen Furnace/ Boiler	Retail	Time of Sale	0%	0%	0%	0%	0%	1%	5%
		New Construction	0%	0%	0%	0%	1%	5%	10%
	Office	Time of Sale	0%	0%	0%	0%	0%	1%	5%
		New Construction	0%	0%	0%	0%	1%	5%	10%
	Institutional	Time of Sale	0%	0%	0%	0%	0%	1%	5%
		New Construction	0%	0%	0%	0%	1%	5%	10%
	Other	Time of Sale	0%	0%	0%	0%	0%	1%	5%
		New Construction	0%	0%	0%	0%	1%	5%	10%
Low Flow Fixtures	Retail	New Construction	0%	30%	80%	80%	80%	80%	80%
	Office	New Construction	0%	30%	80%	80%	80%	80%	80%
	Institutional	New Construction	0%	30%	80%	80%	80%	80%	80%
	Other	New Construction	0%	30%	80%	80%	80%	80%	80%
New Construction - Best Conventional Technologies	Retail	New Construction	0%	3%	20%	100%	100%	100%	100%
	Office	New Construction	0%	3%	20%	100%	100%	100%	100%
	Institutional	New Construction	0%	3%	20%	100%	100%	100%	100%
	Other	New Construction	0%	3%	20%	100%	100%	100%	100%

Commercial Sector Assumptions

Penetration Rate Curves (Con't)

Table 20 (Con't) – Commercial Sector Penetration Rate Curve – Pathway 4 Renewable and Low Carbon Gas Focus (percentage of active units)

Measure Name	Sub-sector	Delivery Type	2020	2025	2030	2035	2040	2045	2050
Replacing Other Use (Incl. CHP) with Electric	Retail	Time of Sale	0%	0%	0%	0%	0%	1%	5%
		New Construction	0%	0%	0%	0%	1%	5%	10%
	Office	Time of Sale	0%	0%	0%	0%	0%	1%	5%
		New Construction	0%	0%	0%	0%	1%	5%	10%
	Institutional	Time of Sale	0%	0%	0%	0%	0%	1%	5%
		New Construction	0%	0%	0%	0%	1%	5%	10%
	Other	Time of Sale	0%	0%	0%	0%	0%	1%	5%
		New Construction	0%	0%	0%	0%	1%	5%	10%
Tankless Water Heaters	Retail	Time of Sale	0%	5%	10%	15%	15%	15%	15%
		New Construction	0%	10%	15%	15%	15%	15%	15%
	Office	Time of Sale	0%	5%	10%	15%	15%	15%	15%
		New Construction	0%	10%	15%	15%	15%	15%	15%
	Institutional	Time of Sale	0%	5%	10%	15%	15%	15%	15%
		New Construction	0%	10%	15%	15%	15%	15%	15%
	Other	Time of Sale	0%	5%	10%	15%	15%	15%	15%
		New Construction	0%	10%	15%	15%	15%	15%	15%

C. INDUSTRIAL SECTOR DEMAND ASSESSMENT/ASSUMPTIONS

The industrial sector modeling is intended to measure gas demand and emissions reduction for the four decarbonization pathways scoped in this study and described in **Section 4.1.2**. The analysis focused on customers to whom utilities deliver natural gas, not industrial customers who deliver gas directly from inter- or intra-state pipelines (bypassing the local distribution company). This non-utility portion of industrial customers is assumed to remain roughly 50% of the total industrial gas consumption in the AEO reference case for all end uses.

Measures evaluated are energy efficiency, direct use of 100% hydrogen, selective electrification, and carbon capture and storage. Those measures were studied for different end uses, including space heating, steam boilers, machine drive, CHP, and other uses.

Table 21 showcases the percentage of energy savings relative to the AEO reference case in 2050. There are two main assumptions behind this calculation:

Maximum end-use applicability: This assumption indicates the share of maximum turnover by end-use during 2050. All measure's lives are set for less than 30 years, and their maximum turnover in 2050 is spread linearly from each measure's starting year to 2050. **Table 22** shows end uses included by measure and the percentages of maximum turnover assigned. When the maximum turnover is zero percent, the end-use is not considered for that pathway and measure. It is the case of space heating electrification under pathways 1 and 4 (see **Table 22**).

Annual efficiency improvement: This input includes efficiency by end-use relative to the reference case for electrification, energy efficiency, and direct use of 100% hydrogen measures. **Table 23** showcases the incremental efficiency relative to the reference case in 2020, and the expected annual efficiency improvement of every measure by end use. It is assumed, in most of the end-uses, that energy efficiency and hydrogen measures are as efficient as the reference case during 2020. Even in these cases in which efficiency levels are identical, there is still significant room for additional efficiency improvements in the future. For instance, in the case of energy efficiency for space heating, despite having the same efficiency level as the baseline, a higher annual efficiency improvement is expected during the subsequent years, which will generate space for energy savings.

Using the inputs described above, the model generates outputs that contain gas demand and GHG annual savings for each measure. Those results were summarized and combined with the DERPM results for residential and commercial sectors and presented in **Section 4.2**.

Table 21 –
Assumptions Driving Industrial Gas Demand (Percentage of 2050 Reference Case)

Industrial Emission Reduction Strategies	Pathway 1	Pathway 2	Pathway 3	Pathway 4
	Gas Energy Efficiency Focus	Hybrid Gas-Electric Heating Focus	Mixed Technology Approach	Renewable and Low Carbon Gases Focus
Incremental Energy Efficiency (saving relative to 2050 reference case)	20%	20%	20%	15%
Direct Use of 100% Hydrogen	10%	10%	10%	17%
Carbon Caputre and Storage	10%	5%	5%	10%
Electrification	2%	9%	16%	2%

Table 22 – Maximum End-Use Applicability by 2050

Measure	End Use	Maximum End Use Applicability 2050			
		Pathway 1	Pathway 2	Pathway 3	Pathway 4
		Gas Energy Efficiency Focus	Hybrid Gas-Electric Heating Focus	Mixed Technology Approach	Renewable and Low Carbon Gases Focus
Electrification	Non-Energy	0%	0%	0%	0%
	Space Heating	0%	38%	50%	0%
	Direct-Fired Process Heating	5%	10%	20%	5%
	Steam Boilers	0%	0%	0%	0%
	Machine Drive	0%	10%	25%	0%
	CHP	0%	5%	10%	0%
	Other	0%	25%	25%	0%
Direct Use of 100% Hydrogen	Non-Energy	0%	0%	0%	0%
	Space Heating	5%	5%	5%	5%
	Direct-Fired Process Heating	15%	15%	15%	20%
	Steam Boilers	5%	5%	5%	10%
	Machine Drive	5%	5%	5%	5%
	CHP	5%	5%	5%	20%
	Other	5%	5%	5%	5%
Energy Efficiency	Non-Energy	100%	100%	100%	100%
	Space Heating	100%	100%	100%	100%
	Direct-Fired Process Heating	100%	100%	100%	100%
	Steam Boilers	100%	100%	100%	100%
	Machine Drive	100%	100%	100%	100%
	CHP	100%	100%	100%	100%
	Other	100%	100%	100%	100%
CCS	Non-Energy	0%	0%	0%	0%
	Space Heating	0%	0%	0%	0%
	Direct-Fired Process Heating	20%	12%	12%	20%
	Steam Boilers	20%	12%	12%	20%
	Machine Drive	0%	0%	0%	0%
	CHP	20%	12%	12%	20%
	Other	0%	0%	0%	0%

Table 23 – Annual Efficiency Improvement

Measures	End Use	Efficiency Relative to Reference Case 2020	Annual Efficiency Improvement			
			Pathway 1	Pathway 2	Pathway 3	Pathway 4
			Gas Energy Efficiency Focus	Hybrid Gas-Electric Heating Focus	Mixed Technology Approach	Renewable and Low Carbon Gases Focus
Electrification	Non-Energy	1.00	0.0%	0.0%	0.0%	0.0%
	Space Heating	3.75	0.5%	0.5%	0.5%	0.5%
	Direct-Fired Process Heating	4.00	1.0%	1.0%	1.0%	1.0%
	Steam Boilers	1.25	0.0%	0.0%	0.0%	0.0%
	Machine Drive	3.17	0.1%	0.1%	0.1%	0.1%
	CHP	1.00	0.0%	0.0%	0.0%	0.0%
	Other	2.00	0.0%	0.0%	0.0%	0.0%
Direct Use of 100% Hydrogen	Non-Energy	1.00	0.5%	0.5%	0.5%	0.5%
	Space Heating	1.00	0.5%	0.5%	0.5%	0.5%
	Direct-Fired Process Heating	1.00	1.0%	1.0%	1.0%	1.0%
	Steam Boilers	1.06	0.3%	0.3%	0.3%	0.3%
	Machine Drive	1.00	0.5%	0.5%	0.5%	0.5%
	CHP	1.00	0.3%	0.3%	0.3%	0.3%
	Other	1.00	0.5%	0.5%	0.5%	0.5%
Energy Efficiency	Non-Energy	1.00	1.0%	1.0%	1.0%	1.0%
	Space Heating	1.00	2.0%	2.0%	2.0%	1.5%
	Direct-Fired Process Heating	1.00	2.0%	2.0%	2.0%	1.5%
	Steam Boilers	1.00	1.5%	1.5%	2.0%	1.5%
	Machine Drive	1.00	0.0%	0.5%	0.5%	1.0%
	CHP	1.00	1.0%	1.1%	1.2%	1.0%
	Other	1.00	0.0%	1.0%	1.0%	1.0%
Reference Case	Non-Energy	1.00	0.5%	0.5%	0.5%	0.5%
	Space Heating	1.00	0.4%	0.4%	0.4%	0.4%
	Direct-Fired Process Heating	1.00	1.0%	1.0%	1.0%	1.0%
	Steam Boilers	1.00	0.3%	0.3%	0.3%	0.3%
	Machine Drive	1.00	0.5%	0.5%	0.5%	0.5%
	CHP	1.00	0.3%	0.3%	0.3%	0.3%
	Other	1.00	0.5%	0.5%	0.5%	0.5%

D. UPSTREAM EMISSIONS INTENSITIES

For this study, ICF gathered data on the upstream emissions from conventional geologic natural gas, as well as from RNG and hydrogen. The upstream emissions associated with different energy sources largely depends on the production inputs.

Most current hydrogen production processes utilize geologic natural gas through steam methane reformation (SMR). As discussed in **Section 3.2.2**, gray hydrogen generally has a higher upstream emissions footprint than geologic natural gas. Pairing SMR with carbon capture reduces the emissions footprint of blue hydrogen such that upstream emissions from blue hydrogen could be comparable to that of upstream emissions from geologic natural gas (blue hydrogen, with no combustion emissions, has a lower emissions profile than geologic natural gas overall). Alternatively, electrolysis powered by renewable electricity generates green hydrogen with a greenhouse gas footprint that is approximately zero.

The processing emissions for methanated hydrogen are not well-studied, so this study assumed they were equal to the upstream emissions profile of hydrogen. It is possible that additional processing of hydrogen into methanated hydrogen could be powered by zero-emissions electricity. Methanated hydrogen's upstream emissions are an area of ongoing study. **Section 4.5.1** addressed that RNG, as a dominant supply of low-carbon energy across all four pathways, is of particular interest in GHG accounting for gas utilities. RNG upstream emissions accounting evaluates the emissions from RNG processing inputs, relative to the emissions that would be released in a base-case scenario where the feedstock materials were not processed into RNG. In some cases, processing these materials prevents carbon dioxide and/ or methane emissions from being released into the atmosphere; these are classified as avoided emissions.

Table 24 and **Table 25** demonstrate an example of 'status-quo' emissions from different RNG production processes, as well as avoided emissions for feedstocks like dairy manure and food waste, where RNG production is lowering methane emissions to the atmosphere (producing a negative emissions credit). These tables also include the upstream and customer emissions components for geologic natural gas, as a point of comparison.[126] In this Appendix, ICF demonstrates how the RNG upstream emissions expected today could reduce in a decarbonized future to the values demonstrated in **Table 6**.

These are emission factors based on CARB models that are meant to be illustrative of current RNG supplies. Other work has shown both higher and lower RNG greenhouse gas emissions intensities and potential avoided emissions than what are presented in **Table 24** and **Table 25**, but the emission reduction opportunities explored here apply regardless of the exact values used.

126 An important distinction is that where most of the geologic gas emissions are accounted for as customer emissions from its combustion, the emissions from RNG occur largely upstream because combustion of biogenic RNG is counted as carbon neutral at the point of combustion (as outlined previously in **Section 4.4**).

Table 24 – Example of Current GHG Emission Factors in the RNG Supply Chain from Anaerobic Digestion of Feedstocks, Compared to Geologic Natural Gas (in $kgCO_2e/MMBtu$)

RNG Production Process Anaerobic Digestion		Dairy Manure	Food Waste	Landfill Gas	WRRFs	Geologic Natural Gas
Collection & Processing	Feedstock Collection	—	2.0	—	—	7.8
	Digestion & Gas Processing	49.8	38.2	35.2	34.5	
	Avoided Emissions	-239.5	-109.8	—	—	—
Pipeline/ Transmission	Transmission[127]	3.0	3.0	3.0	3.0	3.0
End-Uses	Combustion	< 0.1	< 0.1	< 0.1	< 0.1	53.1
Total		**-186.7**	**-66.6**	**38.2**	**37.5**	**63.9**

Table 25 – Example of Current GHG Emission Factors in the RNG Supply Chain from Thermal Gasification of Feedstocks, Compared to Geologic Natural Gas (in $kgCO_2e/MMBtu$)

RNG Production Process Thermal Gasification		Agricultural Residue	Forest Residue	Energy Crops	MSW	Geologic Natural Gas
Collection & Processing	Feedstock Collection	2.1	1.7	3.4	2.0	7.8
	Syngas Processing	48.5	48.5	48.5	48.5	
Pipeline/ Transmission	Transmission	3.0	3.0	3.0	3.0	3.0
End-Uses	Combustion	< 0.1	< 0.1	< 0.1	< 0.1	53.1
Total		**53.6**	**53.2**	**55.0**	**53.5**	**63.9**

Key factors driving the carbon intensity of renewable natural gas processing in the tables above include electricity consumption and assumptions used for biogas processing feed loss (fugitive emissions). **Table 24** and **Table 25** modeled the current status of upstream RNG emissions based on an average U.S. Grid Mix and a common industry baseline estimate of 2% feed loss during biogas processing. For some RNG pathways, gas demand (e.g., for heating anaerobic digesters during RNG production) was also a significant contributor to total upstream emissions.

127 Pipeline transmission emissions were based on a national average and assumed to be the same between RNG and geologic natural gas. This component of upstream emissions is dependent on the distance between gas production and consumption and a pipeline leakage rate. In practice, some RNG production operations will be more local – with gas distributed over shorter distances – such that their transmission emissions will be lower than 3.0 $kgCO_2e/MMBtu$.

To understand the sources of typical upstream GHG emissions assumptions for RNG more clearly, the same projects from the previous tables were sorted into different categories in **Table 26**. This categorization makes it easier to understand how the upstream emissions for different feedstocks could change in a carbon-neutral economy.

Table 26 – Example of Current Upstream GHG Contributions by Production Process in the RNG Supply Chain (in kgCO_2e/MMBtu)

RNG Feedstock	Transportation	Electricity Consumption	Gas Consumption	Processing Feed Loss & Flares	Transmission Leaks	Gross Positive Upstream Emissions	Avoided Emissions	Net Upstream Emissions
Dairy Manure	0.0	16.8	17.4	15.6	3.0	52.8	-239.5	**-186.7**
Food Waste	2.0	20.3	2.9	15.0	3.0	43.2	-109.8	**-66.6**
LFG	0.0	21.2	0.0	14.0	3.0	38.2		**38.2**
WRRF	0.0	20.3	0.1	14.0	3.0	37.5		**37.5**
Agricultural Residue	2.1	34.5	0.0	14.0	3.0	53.6		**53.6**
Forest Residue	1.7	34.5	0.0	14.0	3.0	53.2		**53.2**
Energy Crops	3.4	34.5	0.0	14.0	3.0	55.0		**55.0**
MSW	2.0	34.5	0.0	14.0	3.0	53.5		**53.5**

Although this analysis does not include modelling of the power generation or transportation sectors, the study does work under the assumption that there is an economy-wide shift to net-zero. As such, the tables below mirror previous three 'status quo' emission factor tables but consider the effect of a broader energy transition on RNG production.

Assuming that the power sector would achieve net-zero emissions by 2050, and that relevant transportation would also fully decarbonize, means that those categories would no longer contribute to GHG emissions in 2050. RNG upstream emissions across all feedstock production pathways would consequently decrease significantly by 2050.

Further, the current default RNG 'processing feed loss was targeted for improvement. The industry standard assumption of 2% feed loss[128] is meant to simplify the accounting for gas loss between bio/syngas processing equipment components that are hard to measure precisely. This estimate is based on old literature and is difficult to refute on most projects because the meters on the inlet and outlet of the processing equipment are both +/- 3% to 5% accurate—meaning that the metering accuracy is not high enough to confirm gas is not being lost here. This will be a critical area for additional study, to measure actual emissions from this stage of real RNG projects, and take corrective action as needed. Recognizing that gas distribution companies are investing significant efforts to better measure actual methane leaks and reduce those fugitive emissions, this study evaluated the upstream emissions reduction potential if RNG processing feed loss were reduced from 2% to 0.5%. The true levels of reduction will need to be validated, but there is no structural reason this theoretical/assumed source of methane leaks could not be reduced well below the 0.5% level.

Similarly, methane emissions from pipeline transmission leaks (for both geologic and renewable natural gas) and the processing of geologic natural gas were assumed to decrease by 50% by 2030, reducing total geologic natural gas upstream greenhouse gas emissions by about 25%.

128 Argonne GREET Model (anl.gov)
The California Air Resources Board uses a modified version of GREET for its CA-GREET3.0 Model and Tier 1 Simplified Carbon Intensity Calculators. These tools are used to conduct fuel life cycle analyses and develop Low Carbon Fuel Standard-certified carbon intensity scores. GHG intensity data from GREET and CARB's tools were referenced to build this study's estimates of RNG upstream emissions.

Table 27 and **Table 28** below incorporate these changes expected for a carbon-neutral economy and showcase the resulting upstream emissions and offset credit potential for the different RNG feedstocks. These emissions factors are used in the upstream gas emissions pathways shown in **Section 4.5.2**. Capturing changes that could be expected in a carbon-neutral economy results in significant reductions in upstream RNG emissions, significantly increasing the potential for some sources of RNG that reduce methane emissions to generate emission reduction credits.

RNG Processing Feed Loss

Argonne National Laboratory created the Greenhouse gases, Regulated Emissions, and Energy use in Technologies Model (GREET), which is updated annually. Among other things, GREET is a tool used to estimate the energy use and emissions associated with fuel use, and it is common to reference the model as a compilation of the latest information on different fuel pathways. GREET assumes that renewable natural gas processing CH4 leakage amounts to 2% of the RNG feed lost. Feed loss generally reflects the ratio between inlet and outlet, less flaring, of the biogas upgrading skid. This estimate of average feed loss from valves, flanges, covers, etc. during RNG processing is a standard assumption because these leaks are hard to measure but not zero. However, given that methane leaks across the entire gas production, transmission, and distribution systems amount to closer to 1%, the assumption of 2% leakage from this single process seems out of sync with industry efforts to minimize methane emissions.

Table 27 – Example of Potential Low Carbon Future GHG Emission Factors in the RNG Supply Chain from Anaerobic Digestion of Feedstocks, Compared to Geologic Natural Gas (in $kgCO_2e/MMBtu$)

RNG Production Process Anaerobic Digestion		 Dairy Manure	 Food Waste	 Landfill Gas	 WRRFs	Geologic Natural Gas
Collection & Processing	Feedstock Collection	--	--	--	--	6.0
	Digestion & Gas Processing	22.1	6.8	3.5	3.6	
	Avoided Emissions	-239.5	-108.6	--	--	--
Pipeline/ Transmission	Transmission	2.4	2.4	2.4	2.4	2.4
End-Uses	Combustion	< 0.1	< 0.1	< 0.1	< 0.1	53.1
Total		**-214.9**	**-99.4**	**5.9**	**6.0**	**61.5**

Table 28 – Example of Potential Low Carbon Future GHG Emission Factors in the RNG Supply Chain from Thermal Gasification of Feedstocks, Compared to Geologic Natural Gas (in kgCO_2e/MMBtu)

RNG Production Process Thermal Gasification		Agricultural Residue	Forest Residue	Energy Crops	MSW	Geologic Natural Gas
Collection & Processing	Feedstock Collection	--	--	--	--	6.0
	Syngas Processing	3.5	3.5	3.5	3.5	
Pipeline/ Transmission	Transmission	2.4	2.4	2.4	2.4	2.4
End-Uses	Combustion	< 0.1	< 0.1	< 0.1	< 0.1	53.1
Total		**5.9**	**5.9**	**5.9**	**5.9**	**61.5**

With these adjustments, the emission factors found in **Table 6** (repeated below as **Table 29**) could be expected to be representative of average upstream gas emissions by 2050.

Table 29 – Example of Potential Low Carbon Future Upstream GHG Contributions by Production Process in the RNG Supply Chain (in kgCO_2e/MMBtu)

RNG Feedstock	Transportation	Electricity Consumption	Gas Consumption	Processing Feed Loss & Flares	Transmission Leaks	Gross Positive Upstream Emissions	Avoided Emissions	Net Upstream Emissions
Dairy Manure	0.0	0.0	17.4	4.8	2.4	24.5	-239.5	**-214.9**
Food Waste	0.0	0.0	2.9	3.9	2.4	9.2	-108.6	**-99.4**
LFG	0.0	0.0	0.0	3.5	2.4	5.9		**5.9**
WRRF	0.0	0.0	0.1	3.5	2.4	6.0		**6.0**
Agricultural Residue	0.0	0.0	0.0	3.5	2.4	5.9		**5.9**
Forest Residue	0.0	0.0	0.0	3.5	2.4	5.9		**5.9**
Energy Crops	0.0	0.0	0.0	3.5	2.4	5.9		**5.9**
MSW	0.0	0.0	0.0	3.5	2.4	5.9		**5.9**

Again, these greenhouse gas emission profiles are meant to be examples of a decarbonized future, illustrative of how RNG's GHG footprint can decrease with processing improvements. Other resources and studies like CARB's carbon intensities LCFS-certified, might differ from this study, based on different assumptions for feedstocks, facility operations, and gas transmission logistics.

Current RNG production pathways that consume gas in operation usually rely on geologic natural gas to preserve the more valuable biogas for RNG output. Modeling of these pathways estimated 0.24 MMBtu of geologic gas is consumed per MMBtu of dairy RNG output, or in the case of RNG from food waste, 0.04 MMBtu of geologic NG consumed per MMBtu of RNG. **Table 6** / **Table 29** is consistent with this approach, with dairy manure and food waste production processes continuing to use (and to count emissions from using) geologic gas. This was left as-is to avoid overcounting the availability of RNG supply, as the customer demand and supply scenarios were completed in advance of the upstream RNG emissions calculations. It is likely that in a carbon-neutral economy, geologic gas would no longer be the source of energy in these processes—it could be electricity, RNG, or hydrogen. To give context on the potential impact, if only RNG was used to meet these heating requirements, and no efficiency improvements were made, this would be equivalent to 24% of the MMBtu output of dairy manure RNG and 4% of the RNG from food waste, or about 5-7% of the total RNG being required as a 'parasitic' load for RNG production. Given that not all of the available AGA Net-zero 2050 Case' for RNG supply was used in these pathways (particularly the TG sources), there would still be enough RNG to cover the needs in sectors analyzed here. Or, these heating needs could be met in part by electric or blended-hydrogen options. Additionally, any approach that eliminated this use of geologic gas from RNG production would then result in lower upstream emissions from the RNG sources.

ATTACHMENT B

Implications of Policy-Driven Residential Electrification, AGA, July 2018

AGA

100 YEARS

Implications of **Policy-Driven Residential Electrification**

An American Gas Association Study

prepared by ICF

July 2018

ENERGY

IMPORTANT NOTICE:

This is an American Gas Association (AGA) Study. The analysis was prepared for AGA by ICF. AGA defined the cases to be evaluated, and vetted the overall methodology and major assumptions. The EIA 2017 AEO Reference Case, including energy prices, energy consumption trends, energy emissions, and power generation capacity and dispatch projections, was used as the starting point for this analysis.

This report and information and statements herein are based in whole or in part on information obtained from various sources. The study is based on public data on energy costs, costs of customer conversions to electricity, and technology cost trends, and ICF modeling and analysis tools to analyze the costs and emissions impacts of policy-driven residential electrification for each study case. Neither ICF nor AGA make any assurances as to the accuracy of any such information or any conclusions based thereon. Neither ICF nor AGA are responsible for typographical, pictorial or other editorial errors. The report is provided AS IS.

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Implications of Policy-Driven Residential Electrification

As states and local municipalities pursue "deep decarbonization" of their economies and as the electric grid becomes less carbon-intensive some policy-makers and environmental advocates are looking at mandated residential electrification as one option for reducing residential greenhouse gas (GHG) emissions. This AGA study sets out to answer several key questions regarding potential costs and benefits of these residential electrification policies.[1] These questions include:

- Will policy-driven residential electrification actually reduce emissions?
- How will policy-driven residential electrification impact natural gas utility customers?
- What will be the impacts on the power sector and on electric transmission infrastructure requirements?
- What will be the overall cost of policy-driven residential electrification?
- How do the costs of policy-driven residential electrification compare to the costs of other approaches to reducing GHG emissions?

This AGA Study of residential electrification is based on a policy case that requires the halt of sales of furnaces and water heaters fueled by natural gas, fuel oil, and propane, starting in 2023. As existing equipment is replaced and new construction built, the analysis assumes the associated space and water heating requirements would be met solely with electric based technologies. The analysis then estimates the impact of such a policy on annual energy costs for residential end-users, as well as the associated impact on emissions generated by the residential end-use and power generation sectors through 2050.

Key Study Conclusions

- The U.S. Energy Information Administration (EIA) projects that by 2035, direct residential natural gas use will account for less than 4 percent of total GHG emissions, and the sum of natural gas, propane, and fuel oil used in the residential sector accounts for less than 6 percent of total GHG emissions. Reductions from policy-driven residential electrification would reduce GHG emissions by 1 to 1.5 percent of U.S. GHG emissions in 2035. The potential reduction in emissions from the residential sector is partially offset by an increase in emissions from the power generation sector, even in a case where all incremental generating capacity is renewable.

- Based on the 2017 EIA AEO, by 2035 direct residential natural gas use will account for about 4 percent of total GHG emissions, and the sum of natural gas, propane, and fuel oil used in the residential sector will account for about 5 percent of total GHG emissions. The EIA 2017 AEO projects emissions from the generation of electricity supplied to the residential sector to account for about 10 percent of total GHG emissions in 2035, or more than twice the GHG emissions from the direct use of natural gas in the residential sector.

[1] The electric grid is becoming cleaner due to a variety of factors, including low cost natural gas displacing coal, penetration of renewable generating capacity, and retirement of existing lower efficiency fossil fuel units due to changes in regulation and market forces.

- In the policy case, where about 60 percent of the natural gas, fuel oil and propane households are converted to electricity by 2035 in the regions where electrification policy is implmeneted, the total economy-wide increase in energy-related costs (residential consumer costs plus incremental power generation and transmission costs) from policy-driven residential electrification ranges from $590 billion to $1.2 trillion (real 2016 $), which is equal to $1,060 to $1,420 per year for each affected household, depending on the power generation scenario. This reflects three components: i) changes in consumer energy costs between 2023 and 2050, ii) changes in consumer space heating and water heating equipment costs between 2023 and 2035, and iii) incremental power generation and transmission infrastructure costs between 2023 and 2035.
  - Policy-driven electrification would increase the average residential household energy-related costs (amortized appliance and electric system upgrade costs and utility bill payments) of affected households by between $750 and $910 per year, or about 38 percent to 46 percent.
  - Widespread policy-driven residential electrification will lead to increases in peak electric demand, and could shift the U.S. electric grid from summer peaking to winter peaking in every region of the country, resulting in the need for new investments in the electric grid including generation capacity, transmission capacity, and distribution capacity.
- The average cost of U.S. GHG emissions reductions achieved by policy-driven residential electrification would range between $572 and $806 per metric ton of CO_2 reduced, which is significantly higher than the estimated cost of other GHG reduction options.
- The costs and impacts from the residential electrification policy modelled in the study vary widely by region. based on differences in weather, which impacts both the demand for space heating, and the efficiency of the electric heat pumps. There also can be dramatic differences in costs and emissions benefits within a given region or state based on that local unique circumstances and dynamics. Criteria that can influence the results for a city or local region include differences in natural gas and electricity prices, differences in the housing stock, cleanliness of the electric grid, impacts on the local distribution systems.

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Executive Summary

ES-1 Introduction

In recent years there has been a shift in the types of policies that are being proposed to reduce greenhouse gas (GHG) emissions. The first wave of GHG policy initiatives focused primarily on regulation of GHG emissions in the power sector, as well as direct fuel efficiency targets in the transportation sector and appliance efficiency standards in the residential and commercial sectors. However, reducing GHG emissions by 80 percent by 2050, relative to 1990 levels, consistent with the Paris Agreement, has become a stated environmental goal in many states and localities. The initial set of environmental policies is expected to be insufficient to meet these deep decarbonization goals.

As states and local municipalities consider deep decarbonization of their economies and as the electric grid becomes less carbon-intensive policy-makers and environmental advocates are looking at mandated residential electrification as one option for additional reductions in residential GHG emissions.

Underlying these residential electrification proposals is the assumption that once the electric grid becomes sufficiently low-carbon emitting, conversion of fossil-fuel based residential heating loads and other appliances to electricity can further reduce CO_2 emissions.

Proponents have also suggested that this policy would provide a benefit to the electric grid by taking advantage of under-utilized power generation capacity during winter months and would allow for new electric load growth profiles to match with expected renewable generation profiles.

Some stakeholders also view residential electrification as a means of reversing the impact of declining power usage trends on electric utilities and electric utility rates by increasing the number of appliances that run on electricity in residential households.

ES-2 Potential Impacts of Residential Electrification

While policy-driven residential electrification has been discussed in multiple venues, there has been little or no analysis of the overall costs, benefits, and implications of such policies. The AGA engaged ICF to assess the costs and benefits of alternative policy-driven residential electrification cases developed by AGA.

The study addresses a series of fundamental questions including:

- Will policy-driven residential electrification actually reduce emissions and if so, by how much?
- How will policy-driven residential electrification impact natural gas utility customers?
- What will be the impacts on the power sector and on electric transmission infrastructure requirements?
- What will be the overall cost of policy-driven residential electrification?
- How do the costs of policy-driven residential electrification compare to the costs of other approaches to reducing GHG emissions?

The primary rationale for policies requiring electrification of residential space heating and other loads is the potential for reducing overall GHG emissions. However, the resulting increase in electricity demand can lead to increases in GHG emissions from the power sector. Hence, to be successful, the decrease in residential sector GHG emissions resulting from policy-driven residential electrification must be greater than any potential increase in GHG emissions from the incremental electricity generation required to meet the resulting growth in electric loads. This requires both a high efficiency alternative to natural gas and other fuels used in the residential sector, and a low-emitting electric grid.

Emissions from direct-use of fossil fuels that would be displaced by residential electrification are already small relative to total GHG emissions. In 2016, natural gas use in the residential sector contributed less than 4 percent of total U.S. GHG emissions, and total direct fuel consumption by the residential sector contributed less than 5 percent of total U.S. GHG emissions. This limits the total GHG benefit that could theoretically be realized from reducing residential use of fossil fuel technologies.

At the same time, emissions from electric generation needed to meet electric load in the residential sector are already nearly twice as large as direct end use sources in this sector. In 2016 emissions from the electric grid attributable to residential sector demands contributed 10.5 percent of the total U.S. GHG emissions. And while the electric grid is expected to become less CO_2 intensive overtime, much of the country will continue to rely on coal and natural gas generation to some degree.

The EIA 2017 AEO Reference Case (which was used as the baseline for this analysis) projects renewable power generation to increase from 14 percent of total power generation in 2016 to 23 percent by 2035, and for coal power generation to decrease from 32 percent of total power generation in 2016 to 23 percent by 2035. Based on the EIA forecast, the power grid will continue to become less CO_2 intensive over time.

However, the EIA 2017 AEO also projects that the power grid in much of the country will continue to rely on coal and natural gas generation. As a result, in most regions, increased electricity demand due to policy-driven residential electrification through 2035 would lead to an increase in emissions from the electric sector. This highlights the need to consider the trade-off between reduced GHG emissions from direct residential end-uses of fossil fuels and increased emissions from replacement power sources.

Finally, meeting the incremental electric demand resulting from policy-driven residential electrification will potentially require incremental investment in the power generation infrastructure throughout the U.S. On an annual basis, natural gas delivers almost as much energy as electricity to the residential sector, while accounting for fewer GHG emissions. Electrifying the entire residential sector by 2035 would increase peak electric system demand and could require the size of the entire U.S. power generation sector to almost double by 2035.

Insight: Impact of Location

The costs and impacts from the residential electrification policy modelled in the study differ based on location and there can be dramatic differences in costs and emissions benefits within a given region or state based on that local unique circumstances and dynamics. Criteria that can influence the results for a city or local region include differences in weather and climate, natural gas and electricity prices, differences in the housing stock, cleanliness of the electric grid, and the local impacts to the distribution systems or other factors.

The costs and impacts of residential electrification would also differ based on the specifics of the implemented residential electrification policy. Policies that would result in a slower rate of electrification, or include measures designed to reduce the impacts of electrification on peak demand could have smaller impacts on the electric grid and lower overall costs, while more aggressive policies that would force early retirement of non-electric furnaces and water heaters would increase the impacts of electrification on peak demand and increase overall costs.

ES-3 Analysis Approach

The residential electrification policy scenarios evaluated in this study impact both new construction and appliance replacement. Overall, the policy case evaluated would result in the conversion of roughly 60 percent of fossil-fueled housing stock to electricity by 2035 in the regions where the policy is implemented. Although focused on natural gas, the analysis also includes conversion of oil and propane-fueled households, which are assumed to be included in any future policy.

For each new and existing household converted from one of the fossil fuels to electricity, the analysis includes a projection of the life-cycle differences in equipment costs, the costs of electrical upgrades in existing homes, the changes in annual fossil fuel and electricity consumption and energy costs, and the changes in annual and peak period electricity required. The analysis does not include the impact to natural gas or electric rates, nor the cost of local electricity distribution system upgrades that might be necessary to meet the growth in electricity demand, due to the very site-specific nature of such upgrades.

Energy prices, equipment conversion costs, and energy consumption are based on regional data from the EIA AEO 2017 and other public sources.

The heat pump efficiency used in this study is well above what is currently considered a high-efficiency system and assumes a further progression in electric heat pump technology over the life of the study period. The space heating conversions are based on high efficiency air source heat pumps (ASHP) with an average heating seasonal performance factor (HSPF) of 11.5 over the conversion time period (2023-2035). The HSPF rating for the heat pump reflects a design efficiency. Actual space heating efficiency varies based on winter temperatures, with efficiency declining as the temperature becomes colder. For the study, temperature data from 220 different points is used to estimate effective heat pump efficiency at different locations across the country on both an annual and peak period basis.

The water heater conversions from natural gas to electric demand are based on a heat pump water heater with an average efficiency of 200 percent.

The impact on CO_2 emissions at the household level was estimated based on changes in energy consumption and standard emissions factors. However, the increase in electricity demand due to the electrification policy also leads to potential increases in emissions from the electric generation sector. The impact of the growth in electricity demand on the power grid depends on how the electric grid responds to the increase in electric load. This study evaluated the impacts on electric grid costs and emissions for two different residential electrification cases:

- Renewables-Only Case: In this case, the electric system was constrained from adding new fossil fuel capacity to meet the incremental electricity demand from electrification. The requirement for additional generating capacity was met by a combination of renewable generation and battery storage.
- Market-Based Generation Case: The Market- Based Generation Case was developed in order to evaluate a lower-cost residential electrification case, compared to the Renewables-Only Case. In this case the electric system was allowed to meet the incremental electricity requirements in the most cost-effective way, without limits on fuel choice.

In the Renewables-Only Case, the residential electrification policy was implemented throughout the lower-48 states. In the Market-Based Generation Case, emissions in the Rocky Mountain, Midwest, and Plains states would have increased as the result of policy-driven electrification, hence the residential electrification policy was not implemented in the states in these regions. In both cases, the annual dispatch of the available power capacity was based on the economics of the dispatch, consistent with current regulatory structures.

The analysis of increased electric generation capacity was conducted using an industry recognized power model, ICF's Integrated Planning Model (IPM®), using AGA specified assumptions. The Reference Case reflects the Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2017 forecast.

ES-4 Study Results

Overall, the residential electrification policy assessed in this study would result in the conversion of between 37.3 and 56.3 million households from natural gas, propane, and fuel oil space and water heating to electricity between 2023 and 2035. This represents about 60 percent of the total non-electric households in each region where the policy is implemented. Table ES-1 summarizes the results of the residential electrification cases relative to the Reference Case.

Table ES-1: Summary of Results[2]

	Renewables-Only Case	Market-Based Generation Case
U.S. Greenhouse Gas Emissions	Annual U.S. GHG emissions reduced by 93 million metric tons of CO_2 by 2035 (1.5 percent)	Annual U.S. GHG emissions reduced by 65 million metric tons of CO_2 by 2035 (1 percent)
Residential Households	56.3 million households converted to electricity $760 billion in energy & equipment costs Direct consumer annual cost increase of $910 per household	37.3 million households converted to electricity $415 billion in energy & equipment costs Direct consumer annual cost increase of $750 per household
Power Sector	320 GW of incremental generation capacity required at a cost of $319 billion $107 Billion of associated transmission system upgrades	132 GW of incremental generation capacity required at a cost of $102 billion $53 Billion of associated transmission system upgrades
Total Cost of Policy-Driven Residential Electrification	Total energy costs increase by $1.19 trillion $21,140 average per converted household $1,420 per year per converted household increase in energy costs	Total energy costs increase by $590 billion $15,830 average per converted household $1,060 per year per converted household increase in energy costs
Cost of Emission Reductions	$806 per metric ton of CO_2 reduction	$572 per metric ton of CO_2 reduction

[2] These cost numbers do not include all costs associated with these policies. These costs do not include the cost of local electric distribution system upgrades, do not consider potential natural gas distribution company rate increases on remaining gas customers as the number of natural gas customers declines, or the decrease in natural gas commodity prices that would be expected if total natural gas demand decreases.

At the national level, the analysis of the residential policy-driven electrification cases in this study leads to several important conclusions:

- Policy-driven residential electrification would reduce total U.S. GHG emissions by 1 percent to 1.5 percent in 2035. The potential net reductions in emissions from the residential sector are partially offset by increases in emissions from the power generation sector, even in the case where all incremental generating capacity is renewable.
- Policy-driven residential electrification could increase the national average residential household energy-related costs (amortized appliance and electric system upgrade costs and utility bill payments) by between $750 and $910 per year, or between 38 percent and 46 percent per year.
- Growth in peak winter period electricity demand resulting from policy-driven residential electrification would shift the U.S. electric grid from summer peaking to winter peaking in every region of the country, and would increase the overall electric system peak period requirements, resulting in the need for new investments in the electric grid including generation capacity, transmission capacity, and distribution capacity. Incremental investment in the electric grid could range from $155 billion to $456 billion between 2023 and 2035.
- The total economy-wide increase in energy-related costs (residential consumer costs plus incremental power generation and transmission costs) from policy-driven residential electrification ranges from $590 billion to $1.2 trillion (real 2016 $), which is equal to from $1,060 to $1,420 per year for each affected household, depending on the power generation scenario. This includes changes in consumer energy costs between 2023 and 2050, as well as changes in consumer space heating and water heating equipment costs, and incremental power generation and transmission infrastructure costs between 2023 and 2035.
- The average cost of U.S. GHG emissions reductions achieved by policy-driven residential electrification would range between $572 and $806 per metric ton of CO_2 reduced.

The analysis conducted for this study indicates that significant policy-driven residential electrification efforts would change the overall pattern of electricity demand, and would require major investments in new generating and transmission capacity. Currently, most of the U.S. electric grid is summer peaking, with higher peak demand during the summer than in the winter. As a result, the primary driver of electric grid capacity requirements is peak summer load. The residential electrification policies evaluated in this study do increase summer demand due to conversion of water heaters to electricity. However, natural gas and other fossil fuel space heating load is heavily focused over the winter season, and electrification of space heating would significantly increase electricity demand during the winter, particularly on the coldest winter days when electric heat pump efficiency is lowest, and space heating requirements are the highest.

The increase in peak winter load associated with the electrification of residential space heating cases would convert nearly every region of the U.S. power grid from summer peaking to winter peaking—the incremental generation requirements from electrification policies are typically more pronounced in regions that are already winter peaking.

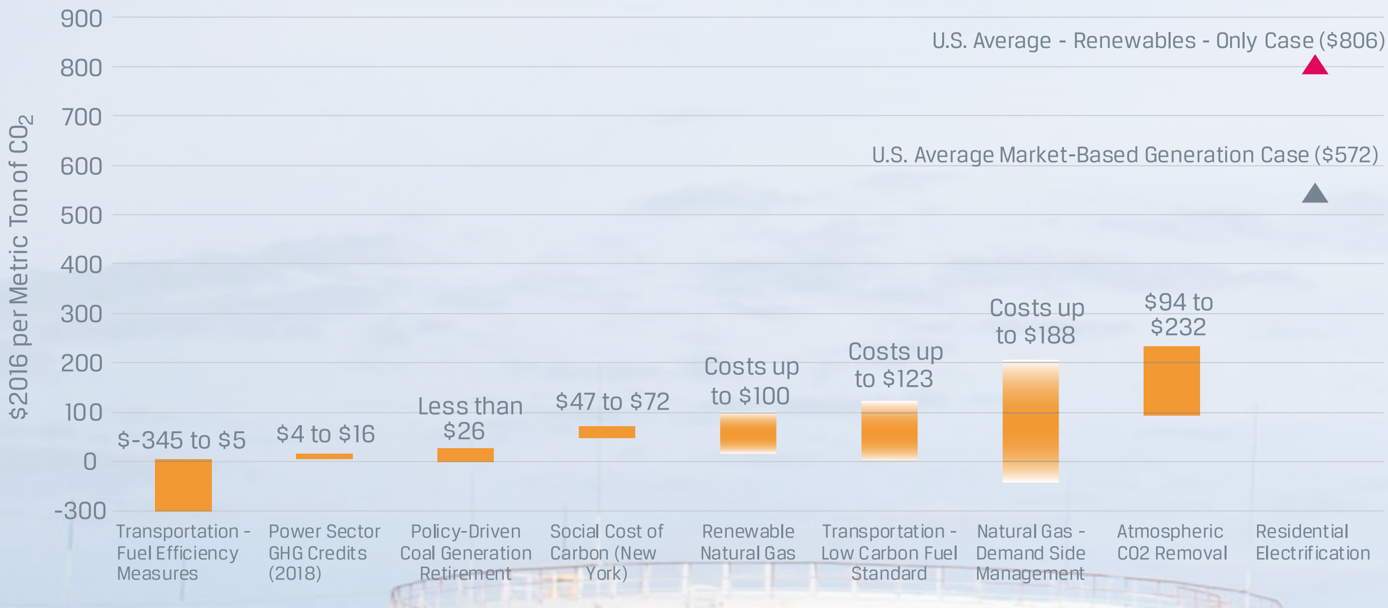
The increase in overall peak electricity demand resulting from the policy-driven residential electrification case would require an increase in total generation capacity in 2035 of between 10 and 28 percent relative to the Reference Case, depending on the power generation case.

The increase in peak demand would also require incremental investments in the transmission and distribution systems. This study includes an estimate for the required incremental investment in transmission capacity. However, it was beyond the scope of the study to assess the potential requirements for additional distribution capacity.

ES-4.1 Cost Effectiveness of Policy-Driven Residential Electrification as a Greenhouse Gas Emissions Reduction Policy

The study of policy-driven electrification of residential fossil fuel heating load (space and water) indicates that residential electrification would be a more expensive approach to greenhouse gas reduction relative to many of the other options being considered—based on considerations related to the emissions reduction potential and the cost competitiveness of this approach relative to other GHG emission reduction options.

Figure ES-1:
Comparison of Cost Ranges for GHG Emissions by Reduction Mechanism



Sources: Energy Innovations, Energy Policy Simulator; GHG emission credits from the most recent auction for the Regional Greenhouse Gas Initiative (RGGI) and California Cap & Trade program; Estimates for GHG reduction costs for the existing coal generation units are based on the Levelized Cost of Energy (LCOE) consistent with the EIA's 2017 AEO Base Case; New York Public Service Commission's (NYPSC's) adoption of the Social Cost of Carbon (SCC); U.C. Davis, The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute, 2016; Comparison of Greenhouse Gas Abatement Costs in California's Transportation Sector presented at the Center for Research in Regulated Industries - 27th Annual Western Conference (2014); The maximum cost of $10 per MMBtu for any Demand Side Management (DSM) program costs is estimated based on an review of public DSM programs; Carbon Engineering, Keith et al., A Process for Capturing CO_2 from the Atmosphere, Joule (2018), https://doi.org/10.1016/j.joule.2018.05.006.

ES-4.2 Overall Conclusions on the Effectiveness of Residential Electrification as a Greenhouse Gas Emissions Reduction Policy

Electrification of direct-use natural gas from the residential sector would result in a significant decrease in the number of residential customers connected to the natural gas distribution system, and a significant decline in natural gas throughput on the system. These changes would result in a material shift in natural gas distribution system costs to the remaining gas utility consumers, including the remaining residential customers, and commercial and industrial sector customers. This study did not include an evaluation of these cost implications to consumers.

This study did not address electrification policies targeted at other sectors of the economy, including the transportation sector, where policy-driven electrification could prove to be a more cost effective approach to reducing GHG emissions. Overall, electrification policy measures aimed at residential natural gas and other non-electric sources of residential energy will be challenged by issues including cost-effectiveness, consumer cost impacts, transmission capacity constraints of the existing electrical system, current and projected electric grid emission levels, and requirements for new investments in the power grid to meet growth in peak generation and transmission requirements .

At the same time, the total GHG emissions reductions available from a policy targeting electrification of residential heating loads represent a small fraction of domestic emissions. Total residential natural gas emissions are expected to account for less than 5 percent of the estimated 6,200 million metric tons of GHG emissions in 2035 in the AEO 2017 Reference Case.[3] Aggressive electrification policies would have the potential to reduce these emissions by up to 1.5 percent of the total U.S. GHG emissions.

[3] The EIA's 2017 AEO Reference Case estimates 4,830 million metric tons of CO_2e in 2035 from combustion sources. An additional 1,370 million metric tons of CO_2e from both combustion and non-combustion is assumed based on 2016 emission levels from those sources.

1 Policy-Driven Residential Electrification—Introduction and Background

In recent years there has been a shift in the types of policies that are being proposed to reduce GHG emissions. The first wave of GHG policy initiatives focused primarily on regulation of GHG emissions in the power sector, as well as direct fuel efficiency targets and clean fuel standards in the transportation sector and appliance efficiency standards in the residential and commercial sectors. More recently, reducing GHG emissions by 80 percent relative to 1990 levels by 2050, consistent with the Paris Agreement, has become a stated environmental goal in many states and localities. The types of policies implemented in the first wave of GHG policy initiatives are expected to be insufficient to meet these deep decarbonization goals.

A second wave of GHG policy initiatives are being proposed and debated primarily at the local and state level, in order to reach these more aggressive targets. A few examples of jurisdictions discussing or implementing these GHG reduction policies include:

- **Denver:** A city task force has recommended policies to "shift commercial buildings and 200,000 households off natural gas to heat sources that do not lead to carbon pollution."[4]
- **Massachusetts:** Legislation has been proposed to require the conversion of residential fossil fuel use to electricity.[5] The state has also proposed establishing targets for 100 percent renewable generation levels in efforts to decarbonize its economy.
- **Ontario:** Various non-governmental organizations promoted residential electrification, which was then aggressively pursued by the provincial environmental agency.[6]
- **Vancouver, British Columbia:** City council plans to position Vancouver as the greenest city in the world include establishing 100 percent renewable energy targets before 2050 and implementing a phased approach to achieving zero emissions in all new buildings by 2030. Some policies that effectively exclude natural gas have been initiated.[7]
- **California, Oregon, Washington:** Various local and state groups are in active discussion regarding the potential for residential electrification policies to reduce GHG emissions.[8]

While these discussions cover a broad range of initiatives and target markets, many also include discussion of residential electrification as one option for reducing GHG emissions.

[4] https://www.denverpost.com/2017/09/06/denver-greenhouse-gas-emissions-renewable-energy/

[5] Massachusetts Senate Bill 1849 and Massachusetts Bill SD1932 (100 Percent Renewable Energy Act)

[6] It was reported in May 2016 that Ontario was considering policies targeting drastic reductions in GHG emissions, including a new building code rules that would have required all homes and small buildings built in 2030 or later to be heated without using fossil fuels, such as natural gas.

[7] http://vancouver.ca/green-vancouver/renewable-city.aspx

[8] California Energy Commission Report, "GHG Emission Benefits and Air Quality Impacts on California Renewable Integration and Electrification," January 2017; SoCal Edison's, "The Clean Power and Electrification Pathway," November 2017; Evolved Energy Research, "Deep Decarbonization Pathways Analysis for Washington State," April 2017; Energy + Environment Economics, "Pacific Northwest Low Carbon Scenario Analysis," November 2017

While policy-driven residential electrification has been discussed in multiple venues, there has been little or no analysis of the overall costs, benefits, and implications of such policies. AGA engaged ICF to develop this analysis of electrification policies for a set of policy cases specified by AGA. The study addresses a series of fundamental questions including:

- Will policy-driven residential electrification actually reduce emissions?
- How will policy-driven residential electrification impact natural gas utility customers?
- What will be the impacts on the power sector and on electric transmission infrastructure requirements?
- What will be the overall cost of policy-driven residential electrification?
- How do the costs of policy-driven residential electrification compare to the costs of other approaches to reducing GHG emissions?

1.1 What is Policy-Driven Residential Electrification?

Simply stated, policy-driven residential electrification is the required conversion of new and existing residential end-uses supplied by fossil fuel technologies with alternative electric appliances. For this analysis, the incremental electricity is provided by the local electric grid.

The underlying concept driving these proposals is the assumption that when the electric grid becomes sufficiently low-carbon emitting, conversion of fossil-fuel based residential heating loads and other appliances to electricity can reduce CO_2 emissions.

Proponents of policy-driven residential electrification have also suggested that this policy would provide a benefit to the electric grid by taking advantage of under-utilized power generation capacity during winter months and would allow for new electric load growth profiles to match with expected renewable generation profiles.

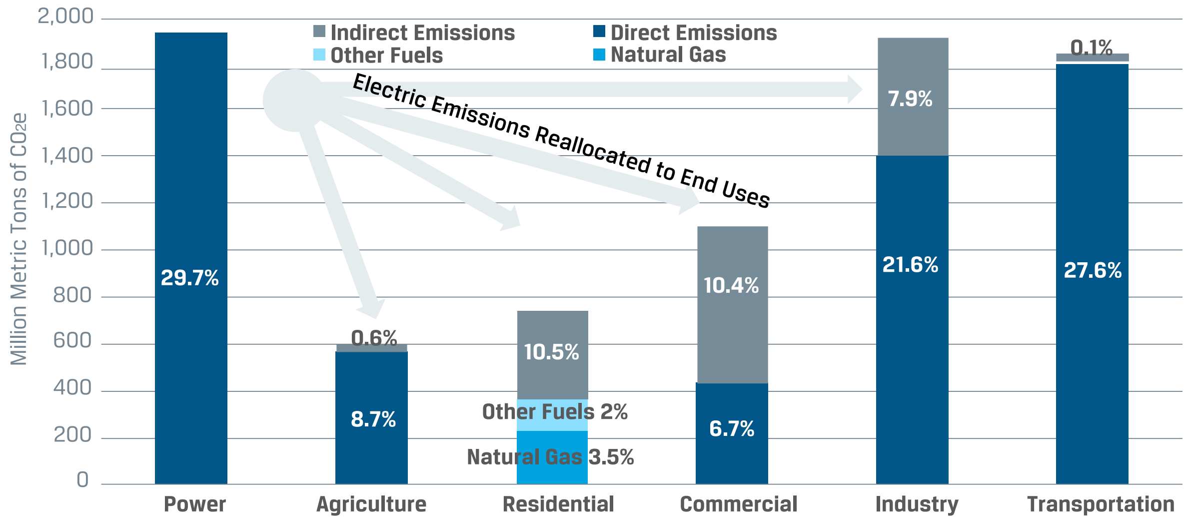
Policy-driven residential electrification also is viewed by some stakeholders as a means of reversing the impact of declining power usage trends on electric utilities and electric utility rates by increasing the number of appliances that run on electricity in residential households.

What are the Potential Environmental Benefits of Residential Electrification?

However, given the complicated interactions of this type of policy proposal, the potential for GHG emission reductions is not always clear and will depend on the relationship between residential electricity demand and the electric grid, which will differ based on regional and local considerations.

Despite the relatively broad interest in residential electrification, the potential benefits in terms of GHG emissions reductions are limited by the overall contribution of residential sector end-use demand to overall GHG emissions.

Figure 1-1:
U.S. GHG Emissions by Source and Sector 2016



Source: EPA GHG Inventory

As shown in Figure 1-1, direct GHG emissions from the residential sector currently comprise only 6 percent of total U.S. GHG emissions, with less than 4 percent coming from natural gas use, including fugitive methane emissions releases.

The residential sector is also responsible for 10.5 percent of total U.S. GHG emissions from its share of the electric sectors emissions. Hence, the emissions from the generation of the electricity used in the residential sector are almost twice as high as residential emissions from other fuels.

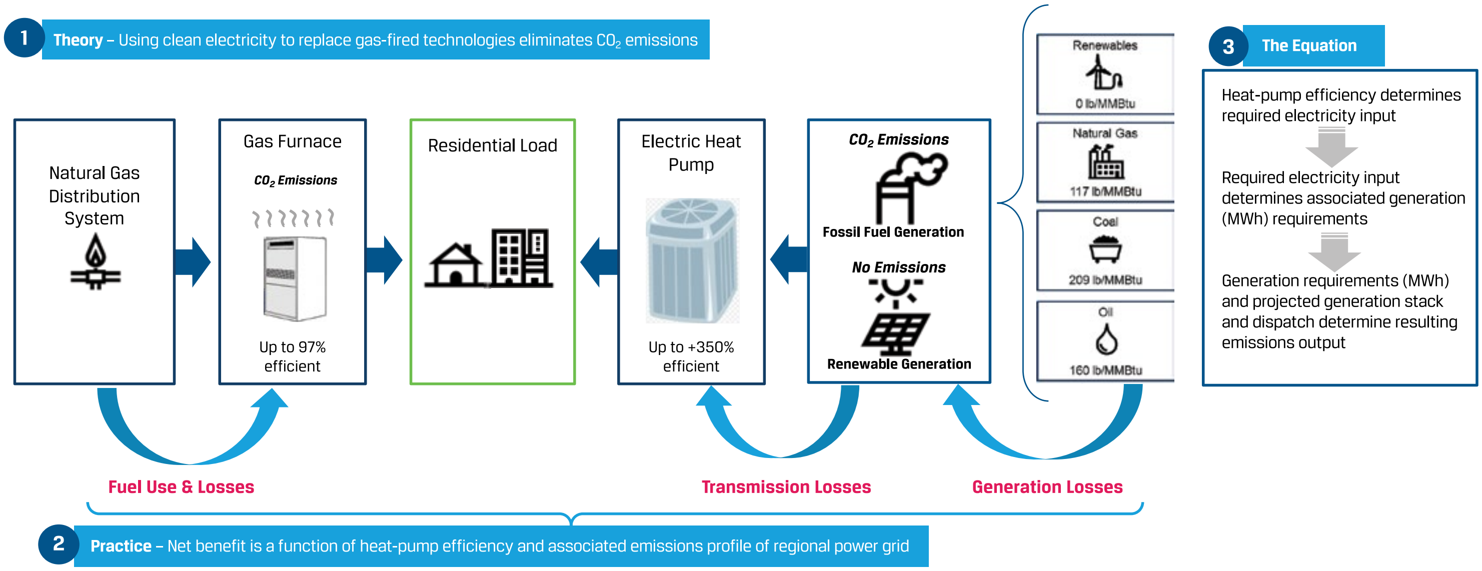
How Would Policy-Driven Residential Electrification Work?

While gas and related fossil fuel residential end-use technologies have achieved high levels of efficiency, their use still involves burning fossil fuels and releasing CO_2 and associated GHG emissions. In contrast, supplying the same MMBtu of heating load with an electric technology, such as a heat pump, results in no direct emissions at the site.

However, to understand the impact of each fuel source on net GHG emissions the full energy-cycle of each fuel path must be considered. This relationship is illustrated in Figure 1-2. In the case of natural gas, this involves the upstream drilling of natural gas, gathering, processing, transmission on interstate pipeline systems, and distribution to residential users. While these are not energy-free activities, they do not add substantially to the net overall energy content of the MMBtu delivered to the residential consumer or impact the residential energy costs significantly.

With the electric system, each Btu of electricity delivered to a residential user must be generated by a power plant, transmitted on high voltage transmission lines, and then across local distribution lines to each individual house. Electric transmission losses alone accounted for a loss of 6 percent of the delivered energy in 2016, compared to a 1 percent loss in natural gas transmission losses. The efficiencies and the GHG emission implications of the upstream generation facilities vary significantly based on the composition of the regional power generation portfolio.

Figure 1-2:
Diagram of Residential Electrification Theory



If all upstream generation resources were renewable or zero-emitting alternatives, displacement of a gas-fired residential technology with an electric technology would result in net emission benefits, regardless of transmission and related losses. However, this does not reflect the current state of the electric grid and/or a realistic expectation in the foreseeable future. As such, to understand the net implications and benefits of residential electrification it is important to place such discussions in the context of the upstream generation portfolio.

What Factors Determine the Net GHG Benefits of Residential Electrification?

The potential environmental benefit of policy-driven residential electrification depends on four critical factors:

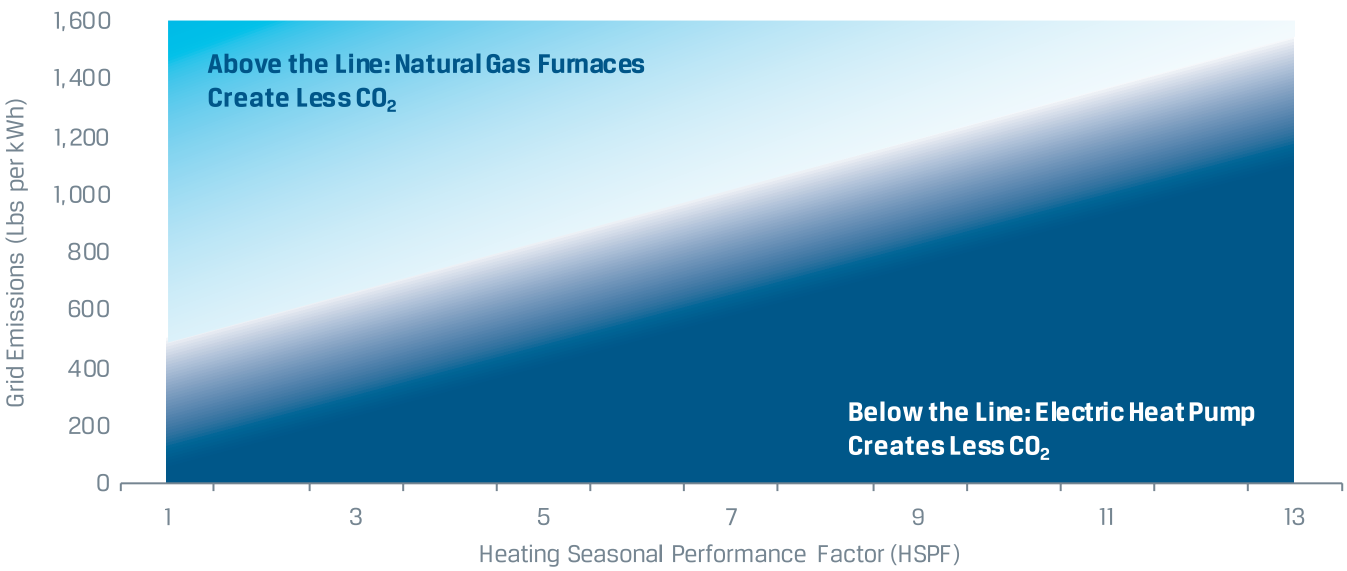
- The heating or water heating load being replaced.
- The efficiency of the appliance facing mandated replacement (e.g., the natural gas furnace and water heaters).
- The seasonal and climate-adjusted efficiency of the replacement electric technology (e.g., heat pump or heat pump water heater).
- The emission rate of the local electric grid used to provide the incremental replacement energy source.

To illustrate this relationship, consider the case of a high efficiency gas furnace being replaced by a heat pump. In warmer regions, the performance of the heat pump relative to the gas-fired furnace will result in greater relative net energy savings.

If this region has a sufficiently low GHG emitting electric grid, transferring energy consumption for the gas-fired technology to the electric technology can reduce net GHG emissions. However, if the same electric grid profile is assumed in a colder region where a heat pump's performance is degraded due to the colder temperatures, the net GHG emission benefits of the policy-driven electrification can be minimal or even negative.

Figure 1-3 shows this relationship. The heat pump performance is shown as actual Heating Seasonal Performance Factor (HSPF)[9], which is a seasonally adjusted efficiency expressed in Btu/Wh and equal to the Coefficient of Performance (COP) factor times 3.4. A gas combined cycle power plant has emissions of approximately 800 pounds of CO_2 per MWh so an electric heat pump needs to operate at an actual HSPF of more than about 7 to have lower emissions than a natural gas furnace.

Figure 1-3: Emissions Reduction For Electric Heat Pumps Based on Weather and Electric Grid Emissions



1.2 Local and Regional Factors

This study's national level impacts were derived from a build-up of more localized analysis. This method was used to capture the unique regional factors for different parts of the country in order to more fully understand the impacts and implications of policy-driven residential electrification policies. The level of detail used in this analysis ranged from city level, to state, to the nine regions used in the study and then aggregated to the national totals.

Due to the complex interaction of the multiple factors involved with modelling the impacts of the residential electrification policy approach used, there are both significant differences in the regional results from the study, as well as significant variations of results within a given region or state based on a wide range of localized issues.

[9] The actual HSPF differs from the nominal HSPF typically used to measure heat pump efficiency. The nominal HSPF is defined for a specific set of climate conditions. Actual HSPF varies with climate and other operational factors. The same heat pump will have a higher actual HSPF in a warmer climate than in a colder climate. In this study, we have defined the heat pump based on nominal HSPF, but have used an estimate of actual HSPF based on Heating Degree Day's (HDDs) on a local level.

Actual emissions from electric generation to meet the growth in electricity demand from policy driven residential electrification for appliances across the U.S. Lower 48 are a result of each region's mix of coal, gas-fired, nuclear, and renewable generation sources, as well as the impact of climate on heat pump efficiency and energy requirements.

These impacts were evaluated on a regional basis to account for differences in both climate (and the relative performance of electric replacement technologies) and regional power grid characteristics. This study presents results using the regions highlighted in Appendix B. The regions were created based on state characteristics, including:

- Electric power pool and grid interconnections
- Natural gas Consumption Profiles
- Regional Climate and Weather Conditions
- Electric Grid Emissions (2035)

1.3 Electric Heat Pump Performance

The residential electrification policies under discussion in different areas generally depend on the replacement of natural gas, propane and fuel oil space heating with electric heat pumps for the majority of the expected environmental benefits. Heat pumps can be very efficient, particularly on an annual basis. However, heat pump performance degrades at lower outdoor temperatures,[10] so heat pump performance must be assessed based on local climatic conditions. In order to assess the overall impacts on the electric grid, the study specifically addressed the question of the impact of the heat pump on peak period electric demand as well as annual electric demand.

Key Factors for Heat Pump Efficiency

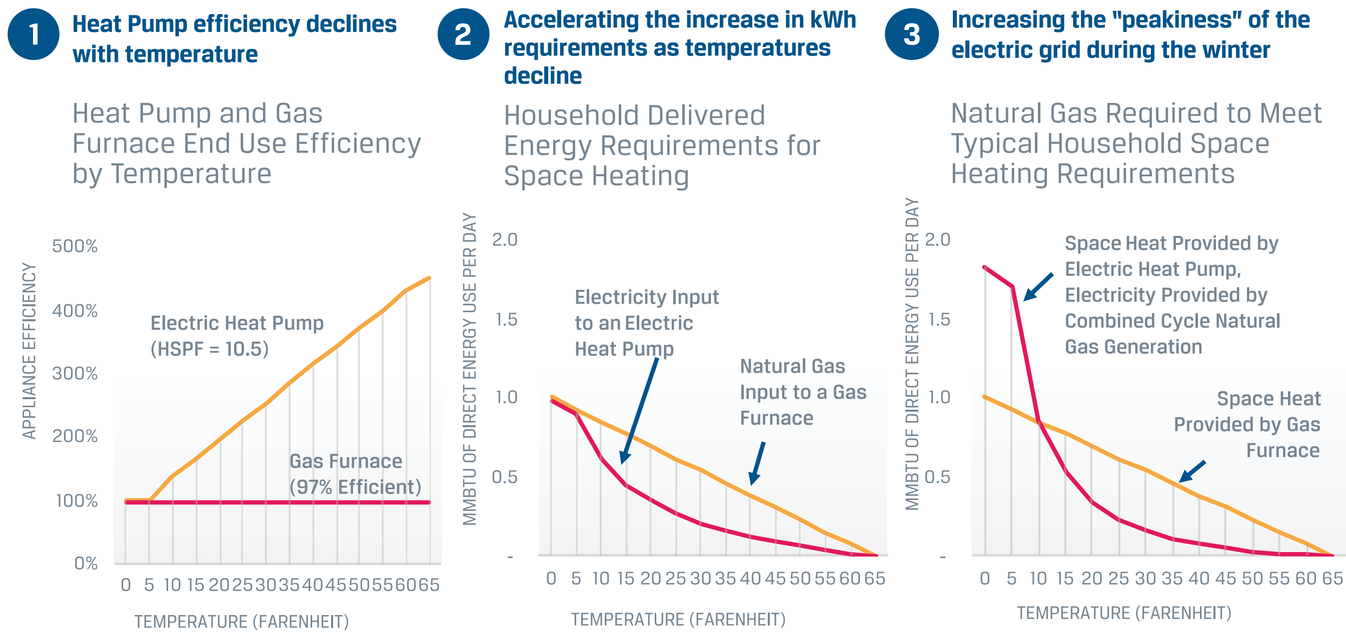
Heat pumps transfer heat rather than transforming chemical energy to heat through combustion. While combustion-based systems can never provide more energy than they consume, i.e., be more than 100 percent efficient, heat pumps can transfer more energy than they consume, i.e., be more than 100 percent efficient. A nominal heat pump efficiency of 300 percent is not unusual under certain operating conditions.

This high efficiency is critical to providing environmental benefits since the higher efficiency of the heat pump offsets the lower efficiency of the electric generating system. However, heat pump performance degrades as the outdoor temperature drops. Falling temperatures affect heat pump performance in three ways:

- The heat pump becomes less efficient.
- The heat pump provides less heat output.
- The discharge air temperature of the heat pump gets lower.

[10] Not all heat pumps degrade at the same rate. The reduction in efficiency for ground source and cold climate heat pumps degrades at a slower rate than conventional heat pumps as outside temperatures decline.

Figure 1-4:
Illustration of Energy Delivery of an Electric Heat Pump and Natural Gas Furnace



In addition, heat pump installations are often sized to meet air conditioning load requirements rather than heating requirements. Oversizing a heat pump to meet peak winter requirements results in more expensive equipment, lower operating efficiency, and additional wear and tear on the equipment during the summer cooling season.

Since peak-day winter requirements occur only a few days each year, and design day conditions occur only every few years, most heat pump installations, including cold climate heat pumps, are designed with electric resistance heat to meet load requirements on the coldest days. The electric resistance heat has an operating efficiency of 100 percent, rather than the average annual operating efficiency of the heat pump which might range from 200 percent to 300 percent (or more).

In addition, at very low temperatures, heat pumps typically cannot provide adequate heat and require some form of back-up energy, typically electric resistance heat. The actual climate-adjusted heat pump performance must be calculated for each region to estimate the consumption and peak demand. This is discussed in Section 2.

Air source heat pumps (ASHP), also referred to as electric heat pumps in this study, have been in commercial use for over 50 years and are a relatively mature technology. Nevertheless, the analysis assumed further performance improvement.

2 Analysis of the Costs and Benefits of Policy-Driven Residential Electrification

In this section, the various cases and assumptions used to evaluate the impact of residential electrification policies are discussed. Descriptions for the following are included:

- **Electrification Policy Definition:** Guidelines for applying a residential electrification program.
- **Analytical Baseline and Alternative Electric Grid Cases:** Key assumptions related to the North American electric grid's response to electrification policies.
- **Impacts on Electricity Consumption and Demand Profiles:** Estimates for the number of households impacted by each policy and the changes in fuel use and electricity demand.
- **Consumer Cost of Electrification:** The development of consumer costs for residential gas-fired and electric appliances.

Though there has been discussion of electrification of residential space and water heating, few specific policies have been proposed by the stakeholders pursuing this agenda. Indeed, public electrification proposals have failed to address many real-world complexities associated with the application of these policies, such as:

- Feasibility of converting the existing household stock, of which a significant number of households would need retrofits to be able to use an electric heat pump.
- Direct consumer costs from the installation of new equipment and any difference in household energy purchases.
- New electric generation requirements and investments to meet new load-growth.
- Impacts on electric transmission networks and implications of a winter-peaking electric system.

2.1 Electrification Policy Definition

In order to perform an analysis of the implications of these policies, the following assumptions were developed for a policy-driven residential electrification policy that could be applied uniformly across the country. For this analysis, it was assumed that an electrification policy would be established in 2020 with the requirements starting in 2023.

Although the primary focus of this analysis is natural gas, it was assumed that the residential electrification policy would also impact fuel oil and propane systems.

The electrification policy included the following key assumptions:

- All new homes after 2023 are built with electric space and water heating appliances only.

- Starting in 2023, any existing direct-fuel use space and water heating systems would be replaced with electric systems at the end of the effective life of the current system. This would result in the conversion of nearly all residential households currently using natural gas, propane, and fuel oil fuels to electricity by 2050 (even households without forced air systems).
- This study does not address market-driven electrification or policy-driven electrification of commercial, industrial, or other sectors.
- The water heater conversions from natural gas to electric demand used a heat pump water heater with an average efficiency of 200 percent.

While the electrification policy was designed to convert all residential households from fossil fuel use to electricity by 2050, the analysis of the impacts of the policy was conducted through 2035, and considered the lifetime costs and benefits through 2050 of all of the households converted to electricity between 2023 and 2035.

2035 represents a point at which significant policy-driven electrification in pursuit of 2050 targets could be assumed to have occurred, but is still near enough that market results could be reasonably analyzed.

Background: Electric Alternatives to Fossil Fuel Space Heating

The analysis of policy-driven residential electrification uses a high efficiency ASHP as the electric alternative fossil fuel space heat throughout the analysis. In the analysis, the efficiency of the average new heat pump is expected to increase by about 1 percent per year, and averages an HSPF of 11.5 (COP of 3.7) over the time period from 2023 through 2035. After accounting for regional differences in weather, and the performance based on the annual temperature load (using the ASHRAE Design Temperature), the heat pumps installed in response to the residential electrification policy are expected to achieve an average winter season COP of 2.6 in the Renewables-Only Case and an average winter season COP of 2.9 in the Market- Based Generation Case. The COPs of the case differ due to the difference in regions covered under each case.

There are also new heat pump technologies that have been proposed as an alternative to the traditional ASHPs for residential electrification purposes. These include:

- **Ground Source Heat Pumps:** Ground source heat pumps use the earth as a heat source and can therefore maintain better cold weather performance. However, they require drilling and placement of underground heat exchangers, which results in much higher costs.
- **Cold Climate Heat Pumps:** Cold-climate heat pumps (ccHP) are still in the development phase but are expected to have better cold weather performance than conventional heat pumps. However, their performance still degrades in cold weather, and many applications will still require back-up heat. The new ccHP's include additional compressors and other equipment, and are expected to be more expensive than the standard high efficiency air source heat pumps.

Many of the current ccHP's are also "mini-split" systems in which the heating unit is a wall-mounted unit similar to a system found in a hotel room, and would not be effective replacements for a central heating system.

- **Heat Pumps with Fossil Fuel Backup:** One potential approach for reducing the impacts of electrification on peak electric grid requirements is to combine a fossil fuel backup (natural gas, propane or fuel oil) with the heat pump to meet space heating requirements on the colder days during the winter. This requires dual space heating systems.

These three systems were not included explicitly in this analysis. GSHP's and ccHP's were not explicitly included due to the incremental costs required for the systems, the general lack of information on the cost and performance of the ccHP's, and the operational challenges and costs associated with retrofitting existing residences with GSHP and ccHP units. However, the average heat pump efficiency used in this study is sufficiently high that it likely would include ccHP's and GSHP's in addition to a mix of medium to high efficiency conventional heat pumps in order to reach the overall average.

Fossil fuel backup was not considered in this study since equipment replacement occurs at the end of the useful life of the existing system, hence would have required the purchase of new fossil fuel equipment as well as the purchase and installation of the heat pump.

Insight: Household Impacts from Electrification Policies Can Vary Significantly

There is a wide range of impacts from policy-driven electrification on consumers based on where the consumer lives, the type of household under consideration, and the age of the household, and the household income.

The per-household cost of residential electrification also can be much greater on consumers in existing homes relative to costs for a newly constructed household. Existing households can often have installation costs more than double the cost difference of a new household, a problem that is particularly acute in older homes that would generally require more extensive retrofit costs and upgrades for electric conversions of heating equipment.

One major concern being raised related to residential electrification proposals is the impact on lower-income consumers. Given the concentration of low income consumers in older homes, the expected cost impacts of policy-driven electrification are expected to fall most heavily on lower income residents.

The relative costs of policy-driven residential electrification would account for a higher share of income for low-income consumers than for the average consumer.

2.2 Alternative Electric Grid Scenarios

A key component of this study was the analysis of the North American electric grid's response to increased electricity consumption and peak demand following the implementation of the residential electrification policy. The study used IPM® to model three separate electrification cases:

- **Reference Case:** For the Reference Case, IPM® was calibrated to reflect the market assumptions from the AEO 2017 Base Case, with no residential electrification policy in place.
- **Renewables-Only Case:** In the Renewables-Only Case, IPM® was constrained so that no new fossil-fueled capacity beyond the capacity built in the reference case would be built to meet the growth in electricity demand resulting from electrification. The only incremental energy generation allowed to meet this new demand was renewable and battery storage—generation from existing fossil-fuel based units was allowed to meet this incremental demand. In this case, electrification policies were applied to all states on the assumption that all new plant construction would be zero-emitting, thus even if the existing emissions were higher than the threshold for environmental benefit in the Reference Case, residential electrification would have the potential for emission reductions. The IPM® model was used to project the changes in generation mix, fuel, and emissions resulting from the policy.
- **Market-Based Generation Case:** In this case, the electric system response to the increase in electricity demand was determined by the market in order to provide a lower cost case than the Renewables-Only Case. The analysis was based on lowest cost mix of generating capacity consistent with environmental and renewable generation policies.

In the Market-Based Generation Case, residential electrification would have increased emissions in certain regions, including the Midwest, Plains and Rocky Mountain regions due to the reliance on incremental natural gas and coal generation to meet the increase in power generation requirements. In these regions, the increase in GHG emissions from the power sector was greater than the reduction in GHG emissions from direct fuel consumption by residential households. In order to avoid a policy that increased net emissions, the residential electrification policy was not implemented in these regions for the Market-Based Generation Case.

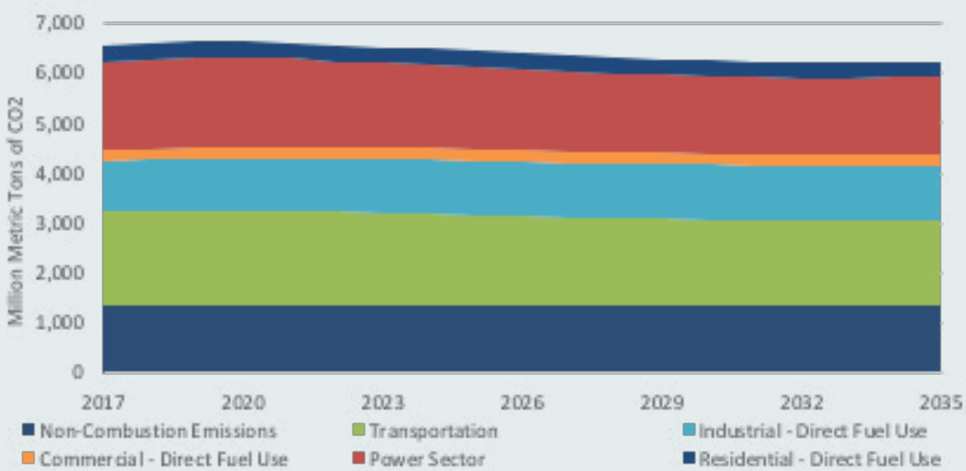
The detailed power sector results of the analysis are presented in Section 3.

Background: Energy Information Agency's 2017 Annual Energy Outlook (AEO)

The EIA's 2017 AEO Base Case forecast is used as the Reference Case for this study. The AEO provides a comprehensive, publicly available forecast of energy consumption, energy prices, and carbon emissions through 2050.

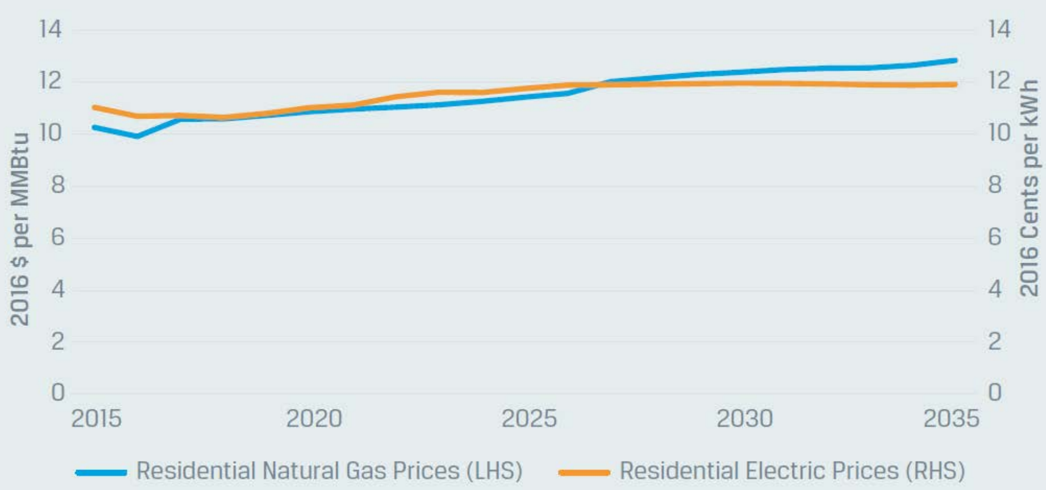
The AEO projects CO_2 emissions from combustion sources to decline from 5,182 million metric tons in 2017 to 4,827 million metric tons in 2035 and 5,084 million metric tons in 2050. Emissions from the power sector decline by 14 percent between 2017 and 2035, primarily due to a 78 percent increase in renewable generation and a decline in coal generation of 22 percent.

Figure 2-1: Total U.S. GHG Emissions (2023 to 2035) in the EIA AEO 2017 Base Case



The relationship between residential electricity and natural gas prices is one of the important determinants of the cost implications of the policy-driven residential electrification analysis. The study used regional AEO price projections to project state-by-state natural gas and electricity prices in the cost analysis. The AEO projects growth in real residential natural gas prices of about 1 percent per year, and real growth in residential electricity prices of about 0.56 percent per year between 2017 and 2035.

Figure 2-2: Average U.S. Residential Prices from EIA's 2017 AEO Base Case (Real 2016 $)



2.3 Household Conversions to Electricity

The Renewables-Only Case, the study assumed that residential electrification policies would be applied in all states. In Figure 2-3, there are 49.8 million natural gas households and 6.4 million oil and propane households converted to electricity by 2035 – representing 60 percent of households using natural gas, propane, and fuel oil under the Reference Case. As a result, there are 36.3 million households that still use fossil-fuels for space and water heating.

In the Market-Based Generation Case, the study assumed that residential electrification policies would only be applied in states where there was a clear emissions benefit based on the state's electric grid emissions profile in 2035 based on the EIA AEO Reference Case (2017). Figure 2-4 shows the conversion impacts for the Market-Based Generation Case. By 2035 this case results in the conversion of 32.4 million natural gas fueled households and 4.8 million oil and propane-fueled households. By 2035 there are 55.3 million households that still use fossil-fuels for space and water heating.

The broader geographic coverage in the Renewables-Only Case results in a greater impact in many aspects of the results and needs to be kept in mind when comparing the results of the two policy cases.

Figure 2-3:
Renewables-Only Case Household Conversions

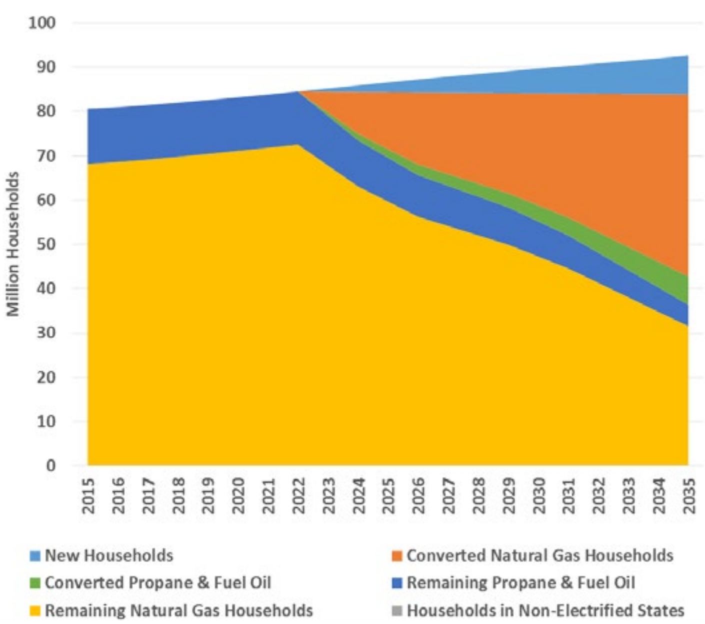
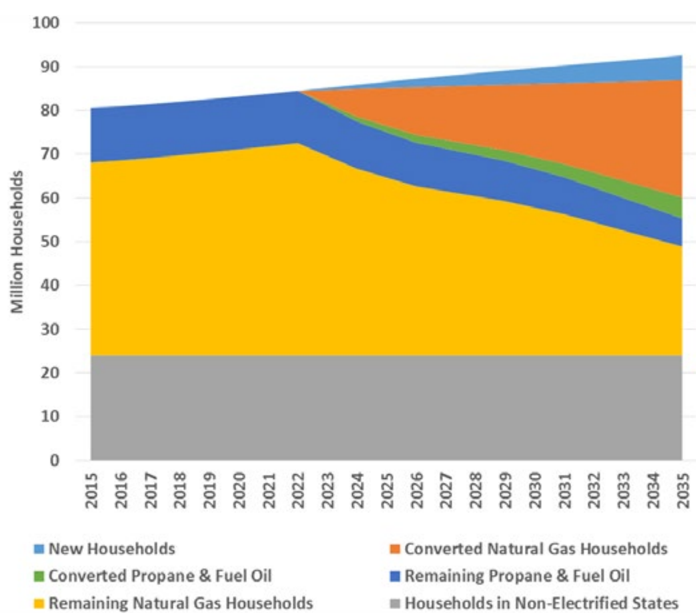


Figure 2-4:
Market-Based Generation Case Household Conversions



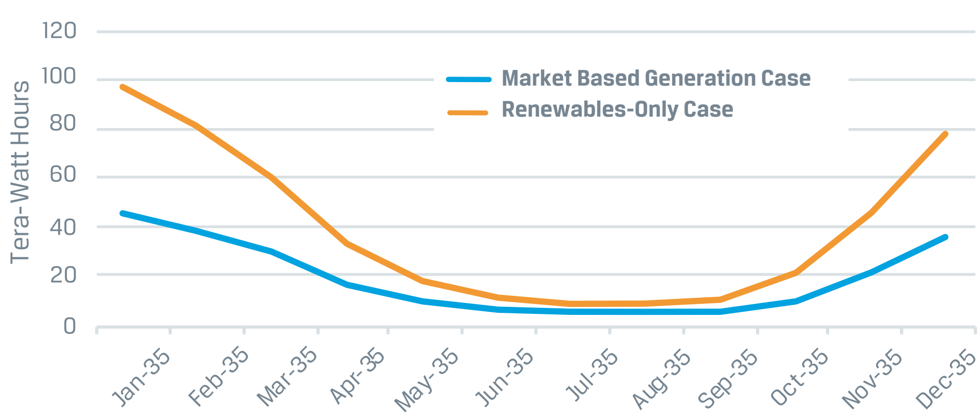
2.4 Impacts on Electricity Consumption and Demand Profiles

For the study, a separate profile was created for the total electricity consumption as well as peak period electric generation requirements in order to fully evaluate the effect of electrification on power system requirements. Electricity consumption is a key variable in understanding the incremental power generation requirements as well as changes in emissions levels and residential energy costs between each case.

Peak electricity demand is a key variable for understanding the impact of electrification policies on electric system capacity requirements. Electric systems must be designed to meet the peak demand at any given time. In many parts of the country the peak demand occurs during summer air conditioning peaks and the system is sized to meet that demand. However the peak in other areas is associated with the peak winter heating load and that peak determines system capacity requirements. As residential space and water heating is electrified in response to the policy-driven electrification mandate, the peak requirements in winter-peaking regions will increase. In regions that are summer peaking in the Reference Case, a certain degree of growth in peak winter demand can occur without significantly impacting the need for electric grid infrastructure. However, when electrification leads to significant growth in space heating demand, regions may switch from summer-peaking to winter-peaking, increasing peak capacity requirements.

- **Incremental Electricity Consumption:** Starting from a baseline natural gas consumption profile for electric generation based on the AEO Reference case, a monthly electric consumption profile was created for use in the electrification cases. This profile includes converted space and water heating demand. To estimate the level of electric demand from space heating conversions, each state's average ASHRAE design temperature and performance characteristics was used for an electric heat pump with an HSPF of 11.5 by 2035, corrected for local climatic conditions.[11] Natural gas water heating usage was converted to an electric water heating system based on current technologies. Water heating demand accounts for the majority of incremental electric demand during the Summer months.

Figure 2-5: 2035 Monthly Electric Consumption by Case



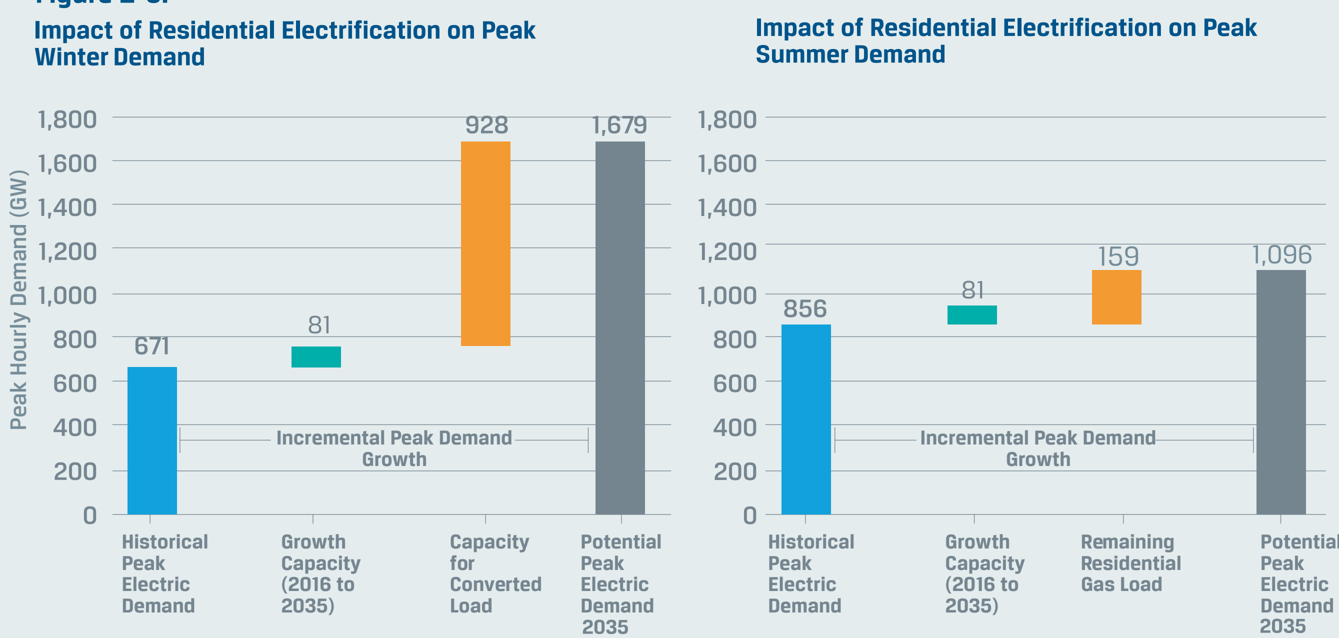
[11] See Appendix A for an explanation of this in the Heating System Efficiency Assumption Section

- **Peak Period Demand:** To determine the impacts of policy-driven residential electrification on peak generation requirements, the first step was to create a peak day sendout for natural gas under the AEO's Reference Case natural gas demand forecast for 2025, 2030 and 2035.[12] Using this peak day demand, an hourly profile of natural gas usage by type (space heating, water heating, and other demand) was developed. The hourly profile was used for estimating the equivalent electric generation requirement based on the heat-pump efficiency at the local design day temperature. Figure 2-6 details the impact of peak period generation on the overall power system capacity requirements for the two cases.

Insight: Impact on Peak-Period Power Demand From 100% Electrification of Residential Natural Gas[13]

Electrifying all direct-use U.S. residential natural gas demand (based on the coincident peak day sendout) would be greater than the highest recorded peak hourly electric generation in the U.S. (July 2011) and 140 percent of highest electric generation ever recorded in the winter (January 2014).[14]

Figure 2-6:



2.5 Consumer Cost of Policy-Driven Residential Electrification

New electric heat pump systems typically have a higher lifetime capital cost (equipment cost and installation cost, adjusted for equipment life) than new natural gas systems. In warm regions, this higher cost can be offset by lower energy costs associated with higher efficiency levels (electric heat pump efficiency is directly tied to the ambient temperature), depending on the relative prices of electricity and natural gas.

[12] A detailed description of the Peak Day Methodology is provided in the Appendix.
[13] The AGA scenarios do not assume 100% electrification.
[14] The estimates for the residential natural gas electrification were developed using the same assumptions outlined in Section 3.3 and Appendix 2, with estimates for space and water heating load derived from the EIA's 2009 RECs data. The historic peak-generation levels were sourced from the Form EIA-861.

However, as shown in the previous section, most of the converted households are not new systems but conversions of existing households, which typically incur higher costs for conversions to new heating system types than for a replacement system. The cost of retrofitting a heat pump to natural gas, propane, or fuel oil system can be much higher than replacing the existing system and can include Incremental costs related to the following requirements:

- Upgrades to electrical services and hook-ups.
- Installation and connection of the outdoor portion of the heat pump.
- Resizing ductwork due to different air flow and discharge temperatures.

Moreover, some natural gas systems are not forced air systems but various types of hydronic systems, such as baseboard or radiator heating systems. If the house does not have ductwork for heating or air conditioning then retrofitting to a central heat pump system would be even more expensive and challenging due to the need to install ductwork.[15]

Table 2-1 shows the appliance replacement costs used for the analysis. There are large first-year cost differences between a natural gas and electric heating system based on whether it is new construction or a retrofit to an existing house. For instance, the first-year cost difference between a gas furnace and electric heat pump in a new household indicate an electric system is lower cost, while system retrofit from natural gas to electric heat pumps typically increase first-year costs significantly. Although first-year costs might be lower for an electric heat pump in a new household, the relative cost differences between natural gas and electric heating systems are heavily dependent on the local natural gas and electric prices as well as the heat pump performance in the local climate. These costs were adjusted to account for regional cost variation.

Table 2-1:
National Installation Costs and Annual Fuel Costs (2035) by Household Heating & Cooling System Type (Real 2016 $)

Household Heating & Cooling System Type	New Household Gas Furnace & AC unit	New Household ASHP[1]	Replacement - Gas Furnace & AC unitv	Conversion of Forced Air Furnace		Conversion of Hydronic System	
	Gas Furnace & A/C	ASHP	Gas Furnace & A/C	ASHP (Existing A/C)	ASHP (No Existing A/C)	ASHP (Existing A/C)	ASHP (No Existing A/C)
Purchase Cost (Capital)	$4,495	$3,903	$4,495	$4,065	$4,065	$4,065	$4,065
Total Installation & Upgrade Costs (1-Year Cost)	$6,281	$5,991	$6,858	$6,993	$10,909	$8,637	$11,509
Annual Equipment Costs	$337	$408	$361	$464	$681	$555	$714
Annual Heating Expense	$998	$1,475	$998	$1,475	$1,475	$1,475	$1,475
Total Annualized Costs	**$1,335**	**$1,883**	**$1,359**	**$1,939**	**$2,156**	**$2,030**	**$2,189**

[15] Mini-split systems could be installed without installing ductwork but might not be acceptable for aesthetic reasons and often would require multiple systems in order to serve all the rooms in a typical single-family home.

2.6 Direct Consumer Cost Impacts from Policy-Driven Residential Electrification

The total impact to consumers from potential electrification policies targeting the residential housing sector will depend on the local conditions (relative energy prices, local climate, and the housing stock's heating and cooling systems). For instance, in most areas across the country residential electricity prices are higher than natural gas prices so electrification can result in higher energy costs if the heat pump is not sufficiently efficient.

Insight: Applicability of National and Regional Results to Specific Utility Service Territories

This study is focused on the national level impacts of potential policies requiring electrification of residential energy load. While the analysis conducted for this study was focused on national level impacts, it is not possible to evaluate the impacts of a potential residential electrification policy without looking at the market in a much more disaggregate manner due to the differences in energy demand, energy prices and other factors in different parts of the country. The study used a variety of different data sources, ranging from sub-state level data on heating degree days, housing stock, and changes in electrical and natural gas demand, to state level data on appliance installation costs, regional data on forecasted energy prices, and other inputs. As a result, the analysis is reported at the regional level as well as the national level. The results have been aggregated into nine regions that reflect major regional differences in climate, natural gas use, and power and transmission grid boundaries.

However, the results shown for each region reflect broad averages, and do not include all local cost differences. The study also did not consider the cost impacts on the electric utility distribution system, which are expected to be significant, but are highly utility specific, and difficult to estimate on a national or regional basis. As a result, the regional results reported in this study are unlikely to be representative of individual utility service territories or individual states.

The results of a similar analysis conducted for a specific state or utility service territory within a region may differ significantly from the regional results shown in this report due to:

- Differences in natural gas and electricity prices even within the same region,
- Differences in housing stock,
- Differences in the electric grid, and
- Inclusion of distribution system cost impacts and other factors.

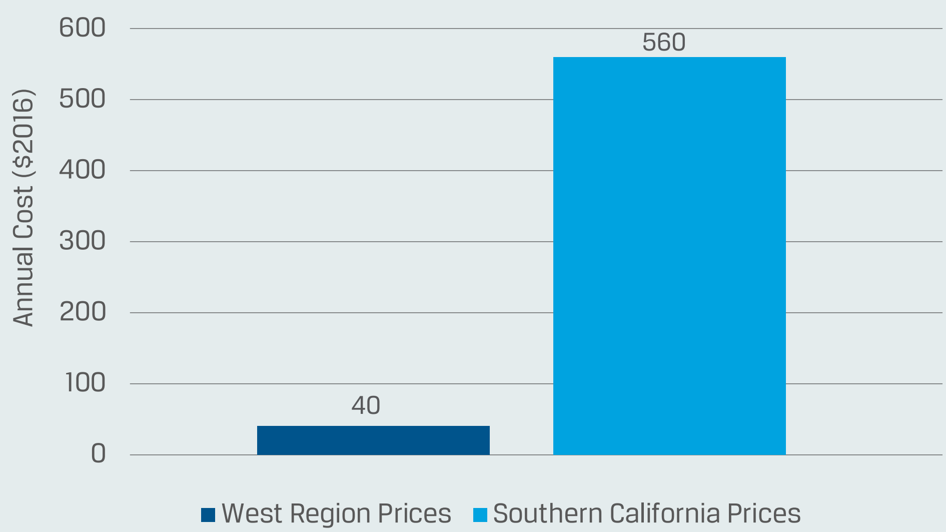
Given the complexity of the issues surrounding residential electrification policies, this study made a number of simplifying assumptions. For instance, this study assumed that all residential households were similar to a national average single-family household, despite the large number of multi-residence households that would be included in these policy proposals. The study found comprehensive data on certain housing characteristics to be limited, and as a result, conservative assumptions for installation and conversion costs were used. In higher cost areas or for households not ideally suited for conversion to electric heating equipment, the actual costs are likely to be understated, particularly for older households and non-single family residential households, which typically are concentrated in lower-income areas.

Case Study: Examining the Impacts of Intra-Regional Residential Prices

In order to illustrate the impact of local conditions relative to the regional averages, we created a simple case study comparing the impact of using Southern California energy prices rather than regional average energy prices on the consumer cost impacts in the Western region.

The projected electricity prices in Southern California (2020) are roughly 37 percent higher than the electricity prices used for the entire West Region, while the local natural gas prices for Southern California were 8.5 percent lower than the regional study price.[16] Using Southern California specific residential rates, when compared to the West's regional average, would result in an incremental increase in consumer's utility bills from $40 per customer reported in the study for the West Region to $560 per year per household, as shown in Figure 2-7.[17]

Figure 2-7: Annual Energy Costs from Electrification Based on Different Residential Rates



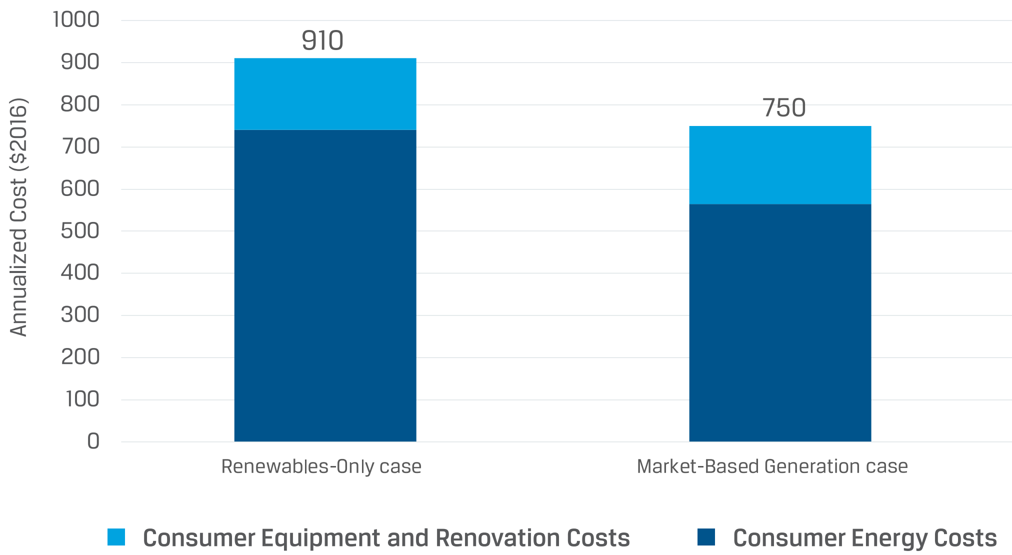
While the study methodology can be applied at the state or utility service territory level, this was beyond the scope of the AGA study. In addition, this type of more localized study approach would also need to consider many costs that were beyond the scope of the study, such as electric distribution costs, natural gas and electric rate impacts and other local considerations not included in this study.

[16] Southern California Rates from California Energy Commission, IEPR Forecasts

[17] Note: It would be inappropriate to use Southern California natural gas and electricity prices for the entire West Region. In addition, if applied only to customers in the Southern California area, the estimated $560 per year would be lower due to lower space heating requirements in this part of the Western Region relative to the overall average.

To capture the differences in the direct costs to consumers[18] from electrification policies, the study considered state level conversion costs for household heating and cooling systems based on state level construction costs, energy usage characteristics, and residential energy rates. These assumptions are more fully documented in Appendix A. These results were then summarized into the nine regions used in this study.

Figure 2-8: Annualized Direct Consumer Costs by Case



Based on this analysis, in the Renewables-Only Case, consumers should expect to see their direct energy expenditures increase by over $760 billion due to higher household fuel purchases and equipment costs. This equates to roughly $910 per converted household per year. (Figure 2-8). In the Market-Based Generation Case, consumers should expect to see their direct energy expenditures increase by about $415 billion. In the Market-Based Generation Case, the average cost per-year nationally would be $750 per converted household.

The reduction in direct energy expenditures in the Market-Based Generation Case relative to the Renewables-Only Case is largely the result of the exclusion of mandated residential electrification policies for the Market-Based Generation Case in the Midwest, Plains, and Rockies regions. These regions have both higher heating loads and are in colder parts of the country, impacting the heat pump performance.

While both cases result in increases in costs to consumers, there is a more nuanced cost impact when evaluating electrification policies in specific regions of the country. Table 2-2 shows the direct consumer costs by each region modelled in this study. One key message from reviewing the regional results is that colder climates with higher heating loads, lower heat pump efficiency, and higher electricity prices relative to natural gas, such as New York and New England, face higher relative costs. Similarly, warm regions with a lower differential in electric and natural gas rates, such as the Southern U.S. can result in lower household fuel purchases and explains why electric heating has made greater inroads in southern cities, even when there are accessible natural gas distribution systems.

[18] Direct costs to consumers include the differences in household capital costs between a natural gas and electric space and water system, and include the differences in household energy purchases over the life of the equipment.

Table 2-2: Annualized Direct Consumer Cost Impacts by Region (Real 2016 $ Per Year Per Household)

The direct consumer costs are derived from households converted from 2023 to 2035. These costs include the installation and equipment costs and the difference in energy purchases for these households from 2023 to 2050 in order to account for future expenditures post-conversions for the natural gas and electric heating systems.

Region	Annual Household Fuel Purchases	Annualized Equipment Conversion Costs	Total Annualized Increase in Consumer Costs per Converted Household
East Coast	770	190	960
Midwest[1]	1,200	150	1,360
New England	1,330	220	1,550
New York	2,630	210	2,840
Plains[1]	910	150	1,070
Rockies[1]	880	140	1,030
South	-330	140	-190
Texas	-120	150	30
West	40	180	230
U.S. Total	**740**	**170**	**910**

[1]These regions were not included in the Market-Based Generation Case since the residential electrification policy would have increased overall GHG emissions.

3 Impact of Policy-Driven Residential Electrification on the Electric Sector

Electrification of residential natural gas and other direct use fuels will increase annual consumption of electricity. It will also increase the demand for electricity during peak periods, including the impact of additional electric space heating on winter peaking, and additional electric water heating on both summer and winter peak periods. Peak period demand is the primary determinant for the overall amount of electrical generation, transmission, and distribution capacity required, and hence determines the overall size of the electrical grid. In most of the country, electricity demand currently peaks during the summer due to air conditioning load. However, some regions of the country experience the electricity demand peak during the winter heating season.

The impact of policy-driven residential electrification depends on the characteristics of the peak electricity demand and the specific region:

- Electrification of residential water heating will have a direct impact on peak electric demand in all regions.
- Electrification of home heating in regions that are already winter peaking will have a direct impact on peak capacity requirements.
- Electrification of home heating in regions that are currently summer peaking will not lead to significant increases in overall peak demand until the conversions create sufficient new winter demand to cause the region to change from summer to winter peaking. Thereafter, additional electrification of space heating will directly contribute to peak period demand.

3.1 Impact on Electric Generation Capacity

The impact of residential electrification on peak electric grid capacity requirements and electric infrastructure is often overlooked in studies of policy-driven residential electrification.[19] This study explicitly projects the potential impact of policy-driven residential electrification on the power grid infrastructure requirements for generation capacity and transmission capacity. Increased demand for electricity is met through the construction of a mix of base load, intermediate load, and peaking generating plants in the Market-Based Generation Case and a combination of renewables and energy storage in the Renewables-Only Case. The need for new plant construction is also affected by retirements of existing plants and environmental and renewable portfolio policies in each region.

For the electric system analysis of the study, the study used IPM® to model the power grid requirements and incremental investments needed to meet electric load growth for each of the three cases described in Section 2. The difference between the Reference Case and each of the two policy cases is used to project the impact of the residential electrification policy on:

- New plant construction by region
- Plant retirements
- Capital expenditure on new plants
- Power plant fuel use and emissions

[19] See, for example: California Energy Commission Report, SoCal Edison's, "The Clean Power and Electrification Pathway," November 2017; Evolved Energy Research, "Deep Decarbonization Pathways Analysis for Washington State," April 2017; Energy + Environment Economics, "Pacific Northwest Low Carbon Scenario Analysis," November 2017

IPM® is a detailed engineering/economic capacity expansion and production-costing model of the power sector supported by an extensive database of every generator in the nation. It is a multi-region model that projects capacity and transmission expansion plans, unit dispatch and compliance decisions, and power and allowance prices, all based on power market fundamentals. IPM® explicitly considers gas, oil, and coal markets, power plant costs and performance characteristics, environmental constraints, and other power market fundamentals. A more detailed description of IPM® is included in Appendix C.

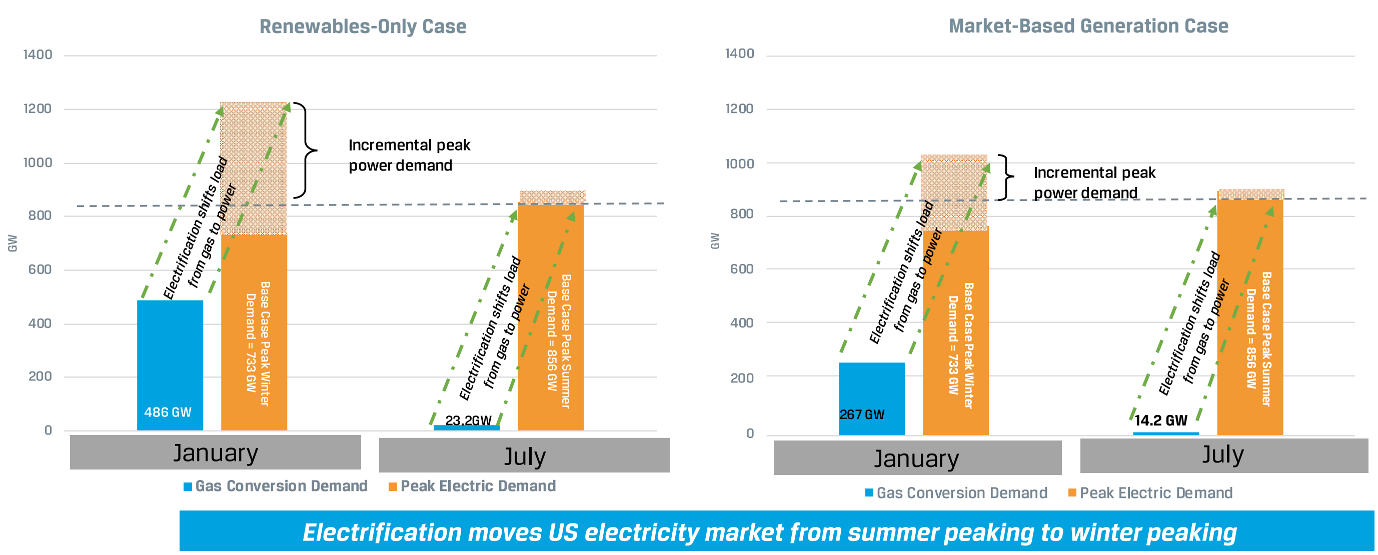
The Reference Case applied the assumptions from the EIA AEO 2017 Reference case, including the Clean Power Plan (CPP).[20] This reference case was calibrated to the EIA results with respect to emissions, total generation mix, levels of total renewable generation, and the mix of newly installed generation capacity. The assumptions were then modified for the policy cases to incorporate the increased electricity consumption and demand from the policy-driven electrification of residential gas use on a regional and seasonal basis.

3.1.1 Impact of Policy-driven Residential Electrification on Peak Period Demand

The effect of electrification on peak electric demand is one of the key drivers of impact on the electricity sector. The impacts are highly dependent on regional weather and generating mix and were modeled on a regional basis. The results also incorporate interactions between generators and transfers between generating regions. Regional results for the power sector analysis are shown in Appendix B, but Figure 3-1 summarizes the national results and illustrates the impact and implications. The figure shows the summer and winter peak demand before and after the policy.

In the AEO 2017 Base Case, or Reference Case, the 2035 peak-hour generation in the winter is 733 GW, 123 GW lower than the summer peak- hour generation of 856 GW. In the Renewables-Only Case, the impacts of electrification increase the winter peak by 486 GW,[21] while the summer peak is increased by only 23 GW (primarily for water heating). The net incremental increase in demand is the winter increase above the pre-existing summer peak capacity or roughly 360 GW.

Figure 3-1: Impact of Residential Electrification on Peak Electric Generation Requirements



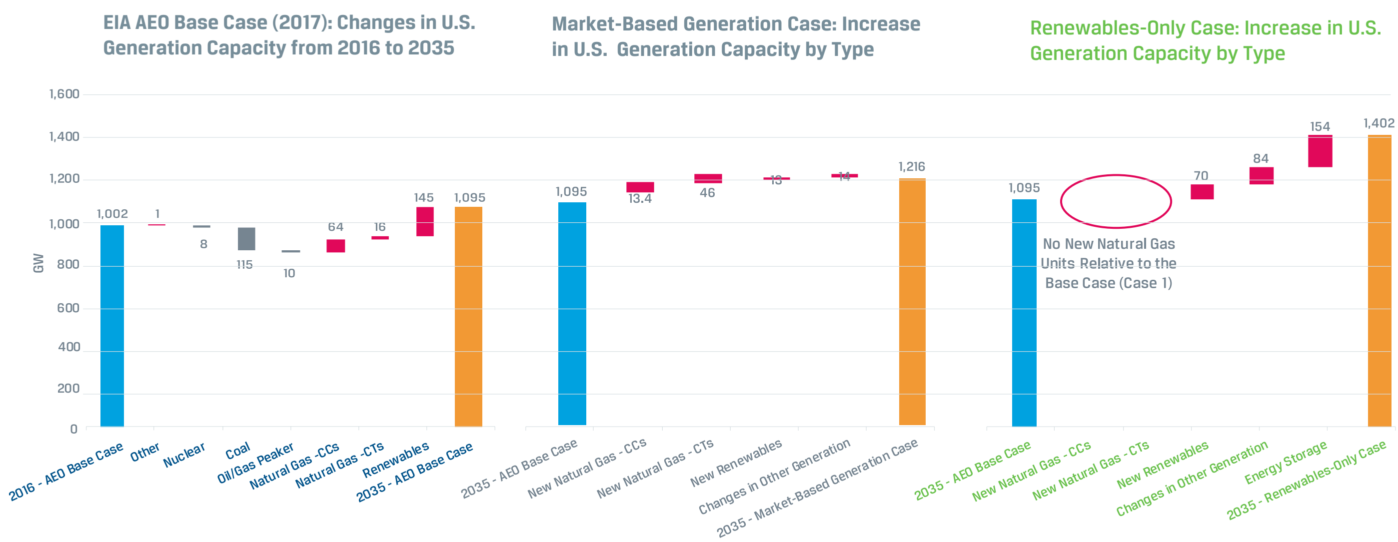
[20] The CPP was put on hold and was not included in the EIA's 2018 AEO Reference Case Assumptions but constitutes a more aggressive environmental case for this analysis.

[21] This is a simplified approach given the differences between coincident and non-coincident peak-hour demand from electrification policies.

In the Market-Based Generation case, the coincident peak-hour increase from electrification is 267 GW and the net incremental generation capacity is 144 GW. The increase for the Renewables-Only case is larger due to the inclusion of electrification in all regions and states within U.S. Lower 48, whereas the Market-Based Generation case excludes several regions. These regions included in the Renewables-Only case have a high penetration of gas heating and are colder, which results in higher demand, exacerbated by lower heat pump efficiency, hence the much higher demand increment.

Figure 3-2 summarizes the projected changes in generating capacity between 2016 and 2035 for the three cases. In the Reference Case, there are 115 GW of retirements of coal-fired plants and 10 GW of retirements for oil/gas steam/peaking units. There are 64 GW of new gas combined-cycle capacity and 145 GW of new renewable capacity.

Figure 3-2:
Changes in U.S. Generating Capacity Due to Residential Electrification



The two policy cases (Renewables-Only and Market-Based Generation) both start from the Reference Case:

- In the Renewables-Only Case, all of the growth in generating capacity needed to meet the electric load growth associated with the policy-driven residential electrification is met with renewable power generation capacity and battery storage capacity. There is no incremental fossil-fuel capacity built in response to the electrification case beyond the capacity built in the Reference Case.
- In the Market-Based Generation Case, the investments in new generating capacity needed to meet the incremental electricity demand associated with the policy-driven residential electrification case are based on the most economic available option, consistent with the environmental regulations (including the CPP) in the 2017 EIA AEO Base Case forecast.

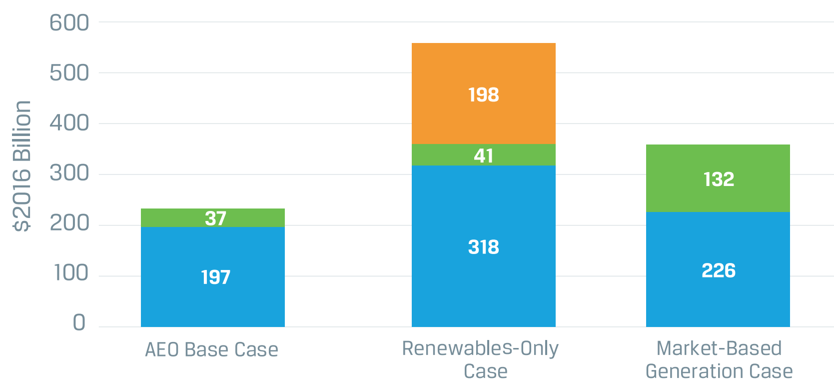
In the Reference Case, the 84 GW of retired capacity was replaced with higher efficiency, lower emitting natural gas combined cycle capacity. In the Renewables-Only Case, we did not allow these units to be replaced with new gas-fired units, which resulted in a delay in the retirement of these units. As a result, the Renewables-Only Case results in higher emissions from existing generation plants than occurs in the Reference Case, which reduces the overall emissions benefits associated with policy-driven electrification.

In the Market-Based Generation Case, the less efficient plants are retired as in the Reference Case and the incremental demand is met primarily with new gas combined cycle (52 GW) and gas combustion turbine peaking units (46 GW), as well as a smaller amount (13 GW) of additional renewable capacity beyond the Reference Case.

3.1.2 Impact of Policy-driven Residential Electrification on Incremental Power Sector Investments

Figure 3-3 shows the cumulative capital investment for generating capacity in North America from 2023 to 2035. The investment in renewable capacity accounts for the majority of the costs in all cases followed by the cost of battery storage in the Renewables-Only Case. The required investment in new generating capacity in the Renewables-Only Case is more than twice as high as the investment in the Reference Case, while electric demand is only 11 percent higher. The increase in investment for the Market-Based Generation Case is about 65 percent of the Renewables-Only Case due to the lower renewable component and lack of battery storage and also because the demand increment is lower for this case.

Figure 3-3: Investment in Generating Capacity by 2035[1]



[1] Investment includes U.S. and Canada power sector costs.

3.1.3 Impact of Policy-driven Residential Electrification on Generation by Source

Figure 3-4 illustrates how the actual generation by fuel changes in the various cases to meet the incremental demand for electricity. The Renewables-Only Case has the highest generation due to the broader geographic coverage of electrification and has the highest renewable generation due to the limitation on construction of new fossil plants. Despite that limitation, fossil generation does not decline significantly in this case due to the delayed retirement of fossil units. Fossil-fueled generation is very similar in the two policy cases.

In the Market-Based Generation Case, much of the gas-based generation is from new, more efficient combined cycle capacity, with implications for gas consumption and emissions.

Figure 3-4:
U.S. Electric Generation by Fuel - 2035 (TWh)

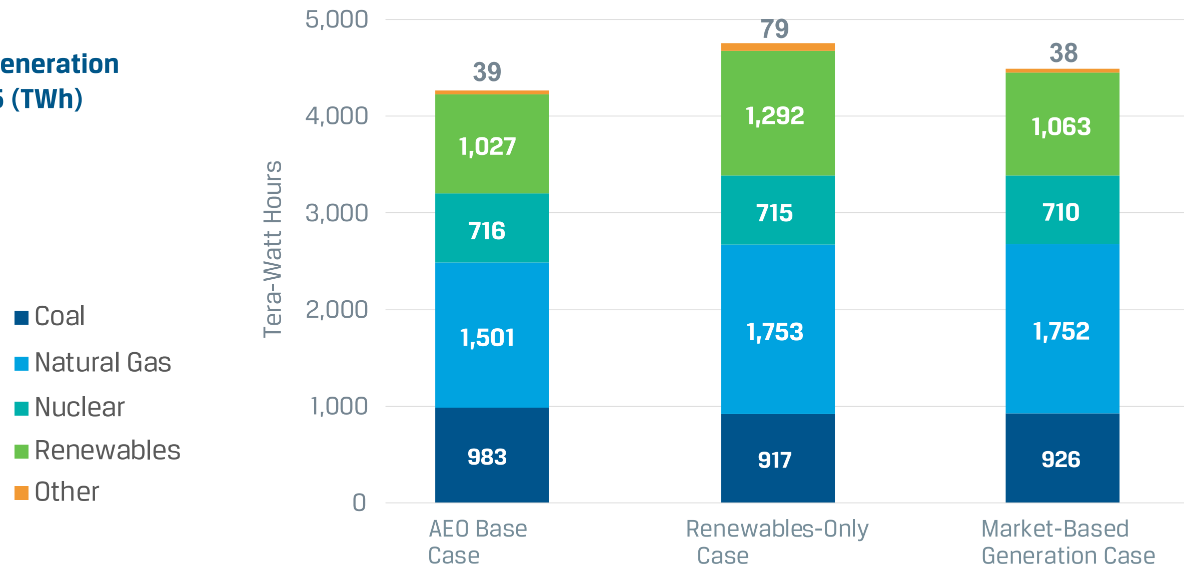
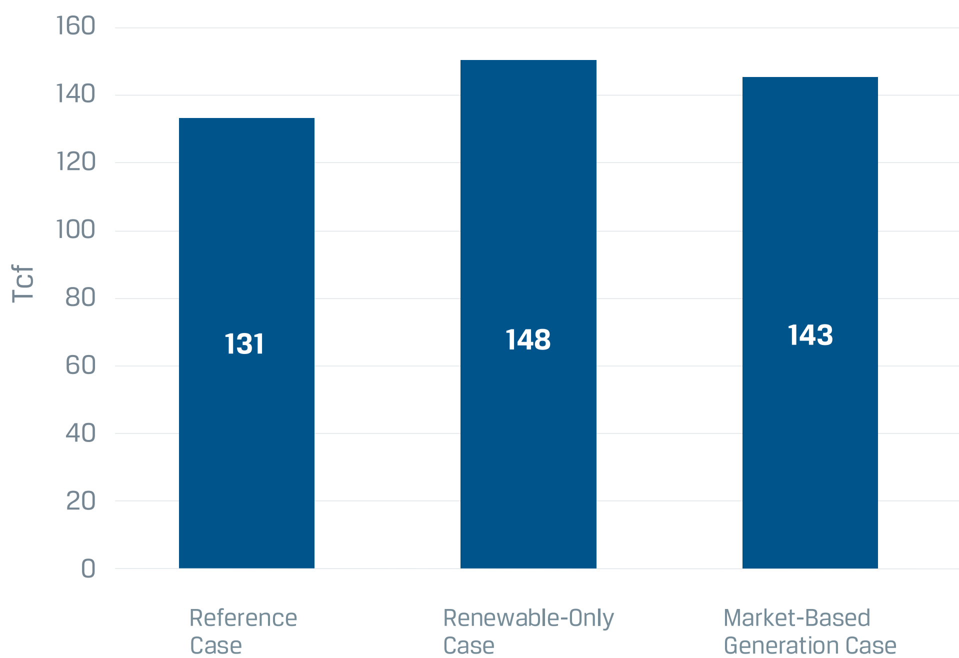


Figure 3-5 shows the gas consumption for power generation in the three cases. Natural gas consumption for electricity production increases in both policy cases as electricity generation increases to meet the increased demand for electric space and water heating loads. This is true even in the Renewables-Only Case as existing gas plants increase their utilization to meet demand and some plants that were retired in the Reference Case remain on line to meet demand. From 2023 to 2035, natural gas consumption for power generation increases by 16.5 Tcf in the Renewables-Only Case and 11.9 Tcf in the Market-Based Generation Case. However, for each case there are offsetting reductions in direct-use natural gas by households from the electrification of space and water heating.

Figure 3-5:
Power Sector Natural Gas Consumption for 2023 to 2035

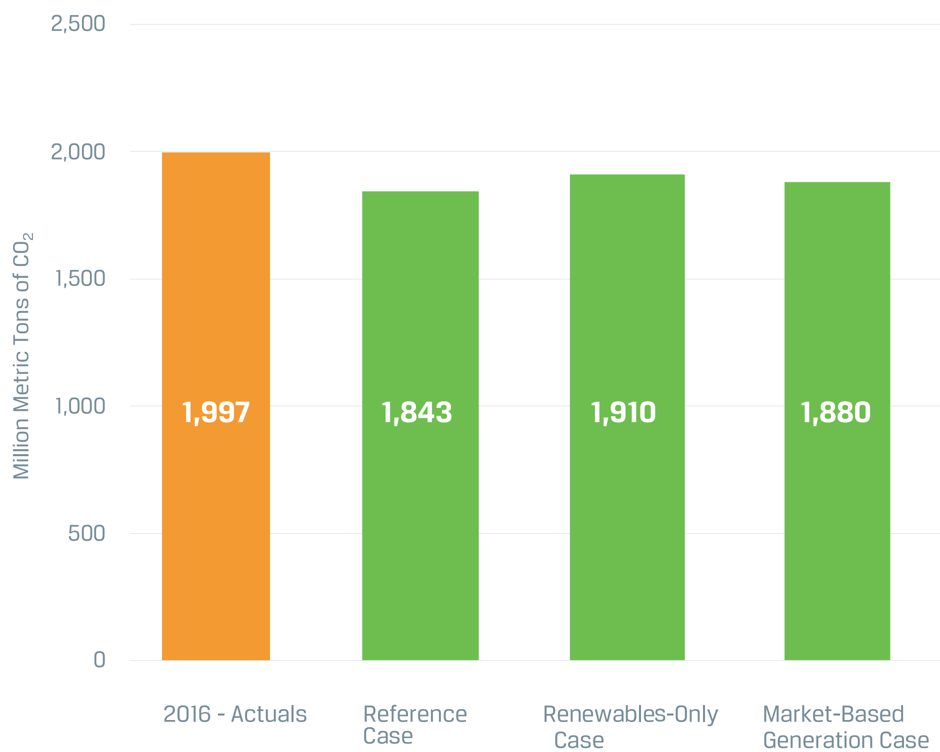


3.1.4 Impact of Policy Driven Residential Electrification on Power Sector CO_2 Emissions

Figure 3-6 shows the power sector emissions of CO_2 for 2016 and the three cases in 2035. In the Reference Case, emissions have declined from 2016 due to coal plant retirements and increased use of gas combined cycles and renewables. Both electrification cases have higher power sector emissions than the Reference Case.

In the Renewables-Only Case, power sector emissions increase due to the increased demand for electricity. In addition, even though no new fossil capacity is allowed, emissions increase due to increased overall generation and greater generation from existing, lower efficiency gas power plants. The Market-Based Generation Case has lower emissions than the Renewables-Only Case because of the lower overall change in generation (due to smaller geographic coverage) and because some older plants are replaced by more efficient/lower-emitting gas combined cycle plants.

Figure 3-6: 2035 U.S. and Canada Power Sector CO_2 Emissions by Case



3.2 Impact on Transmission Requirements

As peak period electricity demand increases and as new electric generating capacity is constructed, the need for additional electric transmission capacity – both local and regional – is also expected to increase. In some cases, generating capacity in one region serves load in an adjacent region, requiring regional transmission. This can be especially important for renewable generation such as wind power, where the potential resources are often in different regions than the demand growth.

This section presents the analysis of electric transmission impacts of the electrification case.[22]

3.2.1 Analytical Approach

The cost of incremental transmission infrastructure that would be needed to meet the higher electric demand levels from the policy-driven electrification was calculated compared to the business-as-usual scenario based on the 2017 EIA AEO Reference Case) for the Market-Based Generation and Renewables-Only cases. To calculate these costs for the study, a detailed review of the transmission network in two of the regions created for this analysis was performed. For these two representative regions, a power flow simulation model was developed that included generation dispatch, regional demand, and net interchange with neighboring regions adjusted to match the peak condition projected by IPM® for the electrification cases.[23] The model simulated the operation of the bulk power system under normal conditions (all assets in service) and contingency conditions (one line or transformer out of service). This identified vulnerable transmission facilities that were likely to be overloaded as a result of the higher demand, and provided estimates for the cost to upgrade these facilities in order to resolve the violations.

Next a detailed model of the East Coast region was created to evaluate the incremental costs from a region that produces a majority of its generation in-region. The Northwestern U.S. in the West region was used to evaluate the transmission costs in a region more reliant on imported electric flows. These two regions were then used as representative regions to extrapolate the transmission costs across all regions.

For each region, the results of the Market-Based Generation and Renewables-Only cases were compared to the Reference Case to identify transmission system overloads unique to the electrification cases. The study also compared the projected inter-regional interchanges to the regional interface transfer limits and estimated the cost of upgrades to increase the limits of interfaces that were found to be deficient.

[22] The transmission infrastructure cost estimates do not include incremental distribution system costs, which vary widely by utility and were beyond the scope of this study.

[23] PowerWorld was licensed to perform the detailed transmission flow modelling.

3.2.2 Impact of Policy-Driven Residential Electrification on Transmission Infrastructure Requirements

Table 3-1 summarizes the results of the transmission analysis.[24] The increased cost for transmission infrastructure in the Renewables-Only Case was estimated at $107.1 billion while the cost in the Market-Based Generation Case was $53.2 billion. The difference is driven in part by the broader geographic coverage and the greater electric demand impact of the Renewables-Only Case. Regional results are presented in Appendix B.

Table 3-1: Total Costs by 2035 of Transmission Investments (Real 2016 $ Billions)[1]

Case	Intra-regional Improvements (Transformers)	Import Facilities (Transmission Lines)	Total Transmission Cost
Renewables-Only Case	91.3	15.8	107.1
Market-Based Generation Case[1]	41.7	11.5	53.2

Note: Transmission costs in the Market-Based Generation case are lower than in the Renewables-Only case in part due to the exclusion of the Plains, Rockies, and Midwest regions from the residential electrification policy in these regions.

Note: The transmission infrastructure cost estimates do not include incremental distribution system costs, which vary widely by utility and were beyond the scope of this study.

The incremental transmission costs vary widely by region, but are dominated in all regions by intra-regional improvements.

The transmission cost analysis should be considered conservative. The analysis did not consider a number of factors that likely would increase the overall transmission cost impacts associated with the electrical load growth driven by mandatory residential electrification policies. These factors include:

- Planning for Stressed Conditions
- Voltage Support
- Zonal Capacity Deliverability
- Permitting challenges, both inter- and intra-state

Additionally, the transmission infrastructure cost estimates do not include incremental distribution system costs, which vary widely by utility.

[24] Two major electric transmissions projects were added in the Renewables-Only case, connecting renewable generation resources in Canada to the Midwest and Northeastern U.S.

4 Overall Impacts of Policy-Driven Residential Electrification

The individual components of the costs and emissions benefits associated with the residential electrification policies evaluated in this study have been reviewed earlier in this report. This section of the report combines these results to assess the overall implications of policy driven residential electrification policies on residential energy costs and the power grid, compared to the potential emissions reductions associated with these policies.

4.1 Overall Cost of Policy-Driven Residential Electrification

The cost impacts from electrification policies include:

Consumer Costs: The direct costs to consumers of policy-driven

electrification include.

- The incremental costs for new or replacement electric space and water heating equipment relative to the natural gas or other direct fuel alternative.
- Costs of upgrading or renovating existing home HVAC and electrical systems.
- Difference in energy costs (utility bills) between the electricity options and the natural gas and other direct fuel options.

Most of the affected households will be existing households retrofitting from natural gas and other direct fuel appliances to electric appliances. The costs for these customers typically will be higher than the incremental costs for new households installing the equipment.

Power Generation Costs: The capital cost of new electric generating capacity needed to supply the increased electricity demand.

Transmission Costs: The cost of new electric transmission infrastructure required to serve the increased load and generation.

Figure 4-1 summarizes these costs for the Renewables- Only Case showing that the total cumulative cost increase relative to the Reference Case is nearly $1.2 trillion by 2035. Roughly half of this cost is the increase in consumer energy costs. One third is the cost of new generating capacity and consumer equipment and transmission costs make up the remainder.

The Market-Based Generation Case has a total cumulative cost increase of $590 billion by 2035, shown in Figure 4-2. The consumer energy costs are lower in this case because it does not include electrification of the Midwestern, Plains, and Rockies regions, which have higher heating loads, greater saturation of gas heating equipment, and colder temperatures, which result in lower efficiency for electric heat pumps. The other costs are also somewhat lower, especially the capital cost of new generating capacity. The generating cost is lower because the model is selecting the lowest cost option, rather than being limited to only renewable sources, which increases costs, especially for battery storage, in the Renewables-Only Case.

Figure 4-1:
Total Cost of Renewables-Only Case by Sector

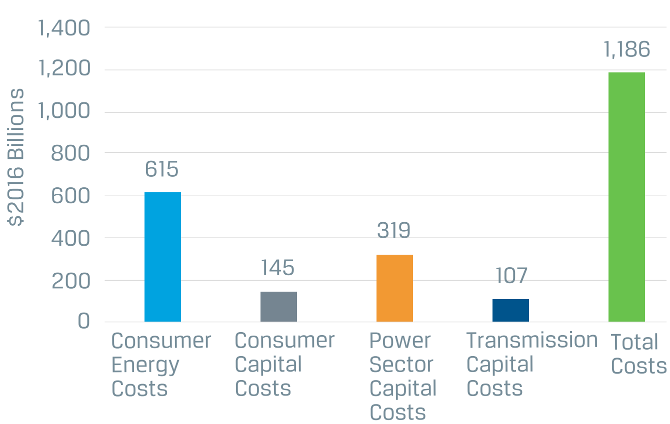
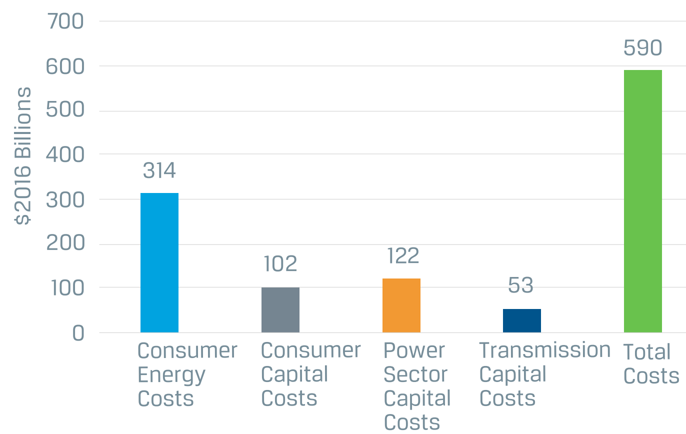


Figure 4-2:
Total Cost of Market-Based Generation Case by Sector



4.2 Cost per Consumer of Policy Driven Residential Electrification

The overall magnitude of the costs of policy-driven residential electrification is expected to place a significant burden on consumers. Table 4-1 shows the cumulative and annualized costs of the conversion to electricity spread out over the total number of converted households. These costs include the direct costs per household, including the direct consumer costs (appliance and energy costs), and an allocation of the capital cost for electric generating plants and electric transmission. The costs are discounted to 2023 and expressed in real 2016 dollars.

One important result from this study was the wide degree of variation in direct consumer costs based on the region of the study.[25]

The cumulative cost per household in the Renewables-Only Case ranged from $1,970 in Texas to over $58,500 in New York, with a national average of $21,140. The annualized cost ranges from $130 to $3,900 per year with a national average of $1,420 per year.

The cumulative cost per household in the Market-Based Generation Case, ranged from $650 in the South region to almost $57,800 in New York, with a national average of $15,830. The annualized cost ranges from $40 per year to nearly $3,880 per year with a national average of over $1,060 per year.

[25]Results within each region can vary significantly based on the local climate and differences in residential energy rates and equipment installation costs.

Table 4-1:
Annual Per Household Total Costs of Electrification Policies (Real 2016 $)[1]

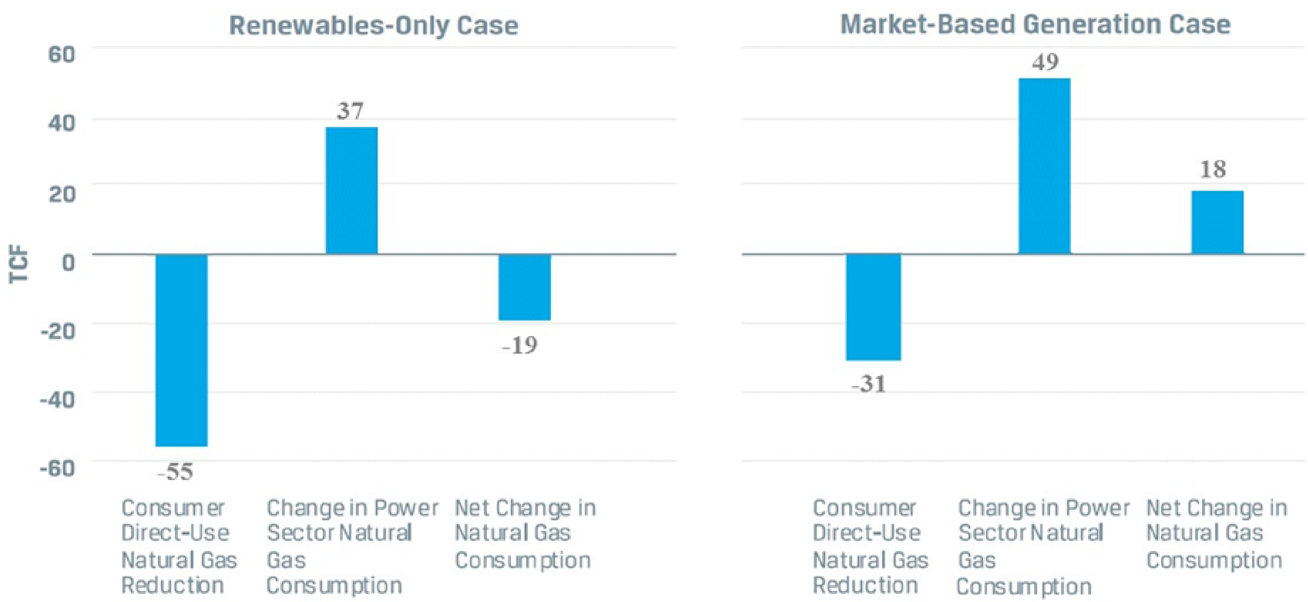
Region	Renewables-Only Case		Market-Based Generation Case	
	Cumulative Change in Costs Per Converted Household	Annualized Change in Costs Per Converted Household	Cumulative Change in Costs Per Converted Household	Annualized Change in Costs Per Converted Household
East Coast	18,440	1,240	16,550	1,110
Midwest	25,920	1,740	Policy Not Implemented	
New York	58,580	3,930	57,770	3,880
New England	41,210	2,770	35,340	2,370
Plains	29,120	1,950	Policy Not Implemented	
Rockies	25,060	1,680	Policy Not Implemented	
South	7,820	520	650	40
Texas	1,970	130	740	50
West	5,880	390	5,140	340
Total U.S.	**21,140**	**1,420**	**15,830**	**1,060**

[1]All costs are discounted in Real 2016 $ to 2023 using a 5 percent discount rate. Costs include direct household conversion costs from 2023 to 2035, power sector and transmission costs from 2023 to 2035 and the cost difference in household energy purchases from 2023 to 2050.

4.3 Net Impacts on Natural Gas Consumption

The residential electrification policies result in a significant reduction in natural gas consumption from home heating and water heating, as well as reductions in fuel oil and propane consumption. However, the growth in electricity demand associated with the residential electrification policies partially offsets the reduction in direct natural gas consumption. Hence the net reduction in natural gas consumption is less than the reduction in direct natural gas use. Figure 4-3 below illustrates the net impact of the residential electrification policy in the two alternative cases.

Figure 4-3:
Change in Cumulative Gas Consumption From – 2023 to 2050



As illustrated in Figure 4-3, the cumulative reduction from 2023 to 2050 in residential natural gas consumption in the Renewables-Only Case is 55 Tcf, or 43 percent of the total residential natural gas consumption in the Reference Case. However, power generation natural gas consumption is projected to increase by 37 Tcf, leading to a net impact on natural gas consumption of 19 Tcf, or about 2.3 percent of total U.S. natural gas consumption over this period.

Natural gas consumption in the power generation sector increases in the Renewables-Only Case due to increased dispatch of the existing natural gas plants, as well as the operation of lower efficiency gas-fired generation capacity that was not retired in this case due to the higher cost of renewable generation capacity.

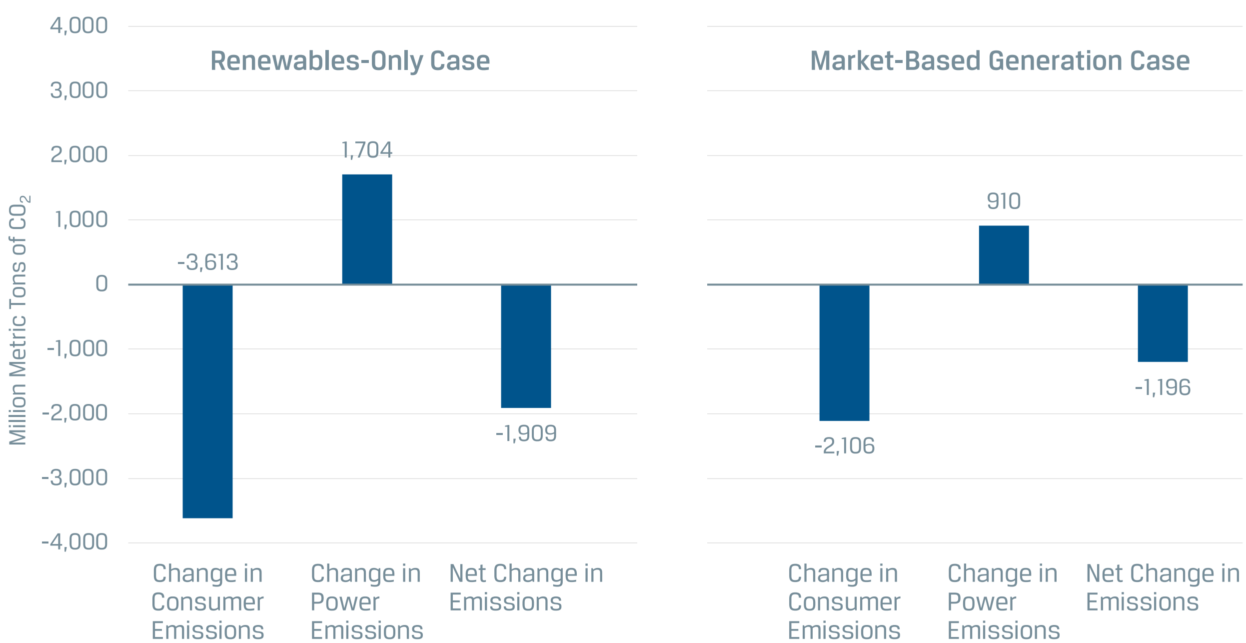
4.4 Net Environmental Impacts

In the Market-Based Generation Case, the reduction in on-site gas consumption is lower than in the All-Renewables Case due to the reduced geographic coverage—a cumulative reduction of Tcf, shown in Figure 4-3. Cumulative gas use for power generation is higher at 49.2 Tcf due to the greater construction

of gas plants to meet the increased electricity demand. As a result, there is a net increase in gas consumption of 18.1 Tcf or about 0.7 Tcf per year. Similar to the impact on natural gas consumption, residential electrification policies are expected to reduce CO_2 emissions from the residential sector, but lead to an increase in emissions from the power generation sector.

Figure 4-4 shows the net change in emissions for the two electrification cases from 2023 to 2050. The Renewables-Only case has the larger on- site reduction due to its larger geographic coverage—a cumulative reduction of 1,909 million metric tons of CO_2 from 2023 to 2050. Despite the prohibition on new fossil fuel

Figure 4-4: Cumulative GHG Emissions Reductions by Electrification Case From - 2023 to 2050



plants to meet the increased demand, CO_2 emissions from the power sector increase by a cumulative total of 1,704 million metric tons of CO_2 (159.7 million metric tons of CO_2 in 2035) due to increased generation from existing fossil-fuel fired generation plants, including natural gas (combined cycles and combustion turbines), coal, and oil-peaking units. This results in a cumulative net emission reduction of 1,909 million metric tons of CO_2, and a total of 96 million metric tons of CO_2 in 2035, which represent about 1 percent of baseline U.S. GHG emissions for that year.

In the Market-Based Generation Case, the cumulative emission reduction is 1,196 million metric tons of CO_2 (65 million metric tons of CO_2 in 2035) due to the exclusion of some regions from the program.

Even though there is more gas generating capacity added than in the Renewables-Only case, the cumulative increase in power sector emissions from the Market-Based Generation case is 910 million metric tons of CO_2 (27.5 million metric tons of CO_2 in 2035). This is lower than in the Renewables-Only Case because the increase in electricity demand is lower and because the new gas plants are more efficient than the older plants that are used in the Renewables-Only Case. Nevertheless, the cumulative total net reduction of emissions is lower, 1,196 Million Metric Tons of CO_2, largely due to the lower geographical application of electrification policies.

Table 4-2: Change in 2035 GHG Emissions by Case (Million Metric Tons of CO_2)

Change in Consumer Emissions	Change in Consumer Emissions	Change in Power Emissions	Net Change in Emissions
Renewables-Only case	-159.7	63.4	-96.3
Market-Based Generation case	-92.7	27.5	-65.2

Even though the Renewables-Only Case prohibits the development of new fossil-fuel generating capacity, and all of the new generating capacity installed in the U.S. in this case is renewable and energy storage, residential electrification still results in higher emissions from the power sector, partially offsetting the larger decline in residential emissions from the expanded application of the electrification policy.

The increase in power sector emissions in the Renewables-Only Case is due to economic market forces in the generation sector and is driven by two factors:

- There are fewer existing natural gas and coal plants retired between 2018 and 2035 than in the Reference Case. In the Reference Case, many of the older existing gas and coal units were driven out of the market by higher efficiency, hence lower cost, new natural gas units. The higher cost of renewable capacity capable of meeting peak winter demands allows these existing units to remain economic longer. These units emit more GHG's than the newer gas units in the baseline.
- The remaining natural gas and coal generating capacity operates at a higher utilization due to the increase in overall electrical load.

4.5 Cost per Ton of CO_2 Emissions Reduced

The primary driver for policy-driven residential electrification is GHG emissions reductions. In order to assess the effectiveness of residential electrification for this purpose, the study calculated the cost implications of the policies based on the cost per metric ton of reduction (Real 2016 $ per metric ton of CO_2 reduced). This is a common figure-of-merit for emission reduction programs and allows comparison of these policies with alternative policies and technologies for GHG reduction.

Table 4-3 shows the emissions cost of reduction from the conversion to electric heating programs and summarizes the cost of emissions reductions for the two policy cases based on the net reductions including increased emissions from the power sector. These costs vary widely among regions based on heating loads, temperature dependent heat pump performance, generating mix, electric transmission capacity, and renewable generation potential among other factors.

For the Renewables-Only Case, the average cost of the net emissions reductions was $806 per metric ton of CO_2. On a regional basis, the costs ranged from $218 per metric ton of CO_2 reduced in the South region to nearly $8,800 per metric ton of CO_2 reduced in New York. The very high cost in New York is due to high costs for the electric generating capacity and infrastructure, high cost of electricity, and cold temperatures reducing heat pump efficiency. Two regions (New England and the Midwest) did not see a reduction in net emissions as growth in power generation emissions more than offset the reduction in residential sector emissions.

Table 4-3: Cost of Emission Reductions (Real 2016 $ Per Metric Ton of CO_2)

Region	Total Cost of Net Emissions Reductions	
	Renewables-Only case	Market-Based Generation case
East Coast	635	391
Midwest[1,2]	N/A	Policy Not Implemented
New York	8,784	6,450
New England[1]	N/A	1,081
Plains[2]	230	Policy Not Implemented
Rockies[2]	794	Policy Not Implemented
South	218	63
Texas	251	54
West	749	485
U.S. Total	**806**	**572**

[1]The Midwest and New England regions show increased total emissions on a Discounted Basis.
[2]In the Market-Based Generation Case, the electrification policy was not implemented in the Midwest, Plains, and Rockies regions due to the lack of potential emissions reductions.

In the Market-Based Generation Case, all regions included in the electrification policy case experienced a net-reduction in GHG emissions. The net cost of emissions reductions by region for the case ranges from $54 to $6,450 per metric ton of CO_2 reduced, with a national average of $572 per metric ton of CO_2. The low cost in the Texas and Southwest regions are due to the mild climate and higher efficiency of heat pumps which result in minimal increases to peak electric generation demand in these summer peaking regions and low incremental energy costs for consumers.

5 Study Conclusions

Overall, the residential electrification policy assessed in this study would convert between 37.3 and 56.3 million households from natural gas, propane, and fuel oil space and water heating to electricity between 2023 and 2035. This represents about 60 percent of the total non-electric households in each region where the policy is implemented. Table 5-1 summarizes the results of the analysis.

5.1 Study Results

Table 5-1: Summary of Results

	Renewables-Only Case	Market-Based Generation Case
U.S. Greenhouse Gas Emissions	Annual U.S. GHG emissions reduced by 93 million metric tons of CO_2 by 2035 (1.5 percent)	Annual U.S. GHG emissions reduced by 65 million metric tons of CO_2 by 2035 (1 percent)
Residential Households	56.3 million households converted to electricity $760 billion in energy & equipment costs Direct consumer annual cost increase of $910 per household	37.3 million households converted to electricity $415 billion in energy & equipment costs Direct consumer annual cost increase of $750 per household
Power Sector	320 GW of incremental generation capacity required at a cost of $319 billion $107 Billion of associated transmission system upgrades	132 GW of incremental generation capacity required at a cost of $102 billion $53 Billion of associated transmission system upgrades
Total Cost of Policy-Driven Residential Electrification	Total energy costs increase by $1.19 trillion $21,140 average per converted household $1,420 per year per converted household increase in energy costs	Total energy costs increase by $590 billion $15,830 average per converted household $1,060 per year per converted household increase in energy costs
Cost of Emission Reductions	$806 per metric ton of CO_2 reduction	$572 per metric ton of CO_2 reduction

Overall, the analysis of the AGA policy-driven residential electrification cases indicates that residential electrification policies would likely result in small reductions in GHG emissions relative to total U.S. emissions, at a cost on a dollar per metric ton basis that would be higher than the cost of other emissions reduction options under consideration, both to individual consumers and society at large.

- Based on the 2017 EIA AEO, by 2035 direct residential natural gas use will account for about 4 percent of total GHG emissions, and the sum of natural gas, propane, and fuel oil used in the residential sector will account for about 5 percent of total GHG emissions. Reductions from policy-driven residential electrification would reduce GHG emissions by 1 percent to 1.5 percent of U.S. GHG emissions in 2035 from the EIA AEO 2017 Baseline emissions.

- GHG emissions from the generation of electricity supplied to the residential sector are expected to account for about 10 percent of total GHG emissions in 2035, or more than twice the GHG emissions from the direct use of natural gas in the residential sector.

- Policy-driven electrification would increase the average residential household energy-related costs (amortized appliance and electric system upgrade costs and utility bill payments) by between $750 and $910 per year, or about 38 to 46 percent above expected energy related costs in the absense of electrification.

- Growth in peak winter period electricity demand resulting from policy-driven residential electrification would shift the U.S. electric grid from summer peaking to winter peaking in every region of the country, and would increase the overall electric system peak period requirements, resulting in the need for major new investments in the electric grid including generation capacity, transmission capacity, and distribution capacity. Incremental investment in the electric grid could range from $155 billion to $456 billion between 2023 and 2035.

- The total economy-wide increase in energy-related costs (residential consumer costs plus incremental power generation and transmission costs) from policy-driven residential electrification ranges from $590 billion to $1.2 trillion (real 2016 $), which is equal to from $1,060 to $1,420 per year for each affected household, depending on the power generation scenario. This reflects changes in consumer energy costs between 2023 and 2050, as well as changes in consumer space heating and water heating equipment costs, and incremental power generation and transmission infrastructure costs between 2023 and 2035.

- The average cost of U.S. GHG emissions reductions achieved by policy-driven residential electrification would be between $572 and $806 per metric ton of CO_2 reduced, well above the costs of other emissions reductions policies under consideration.

5.2 Impact of Policy-Driven Residential Electrification on the Power Grid

The increase in peak winter load associated with the electrification of residential space heating would convert most areas of the U.S. power grid from summer peaking to winter peaking—the incremental generation requirements from electrification policies are typically more pronounced in regions that are already winter peaking.

The analysis conducted for this study indicates that significant residential electrification efforts would change the overall pattern of electricity demand and lead to increases in peak electric demand. Such policies could also shift the U.S. electric grid from summer peaking to winter peaking in most of the country, resulting in the need for major new investments in the electric grid including generation capacity, transmission capacity, and distribution capacity.

Currently, most of the U.S. electric grid is summer peaking, with higher peak demand during the summer than in the winter. As a result, the primary driver of electric grid capacity requirements is peak summer load. The residential electrification policies evaluated in this study do increase summer demand due to conversion of water heaters to electricity. However, natural gas and other fossil fuel space heating load is heavily focused over the winter season, and electrification of space heating will significantly increase electricity demand during the winter, particularly on the coldest winter days when electric heat pump efficiency is lowest, and electricity use for space heating will be the highest.

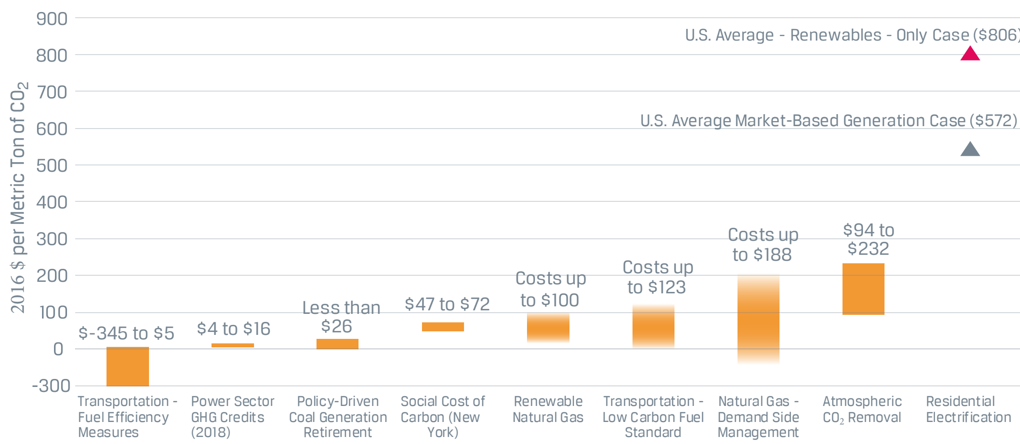
The increase in peak winter demand would lead to an increase in overall peak electric demand, and require an increase in total generation capacity in 2035 of between 10 and 28 percent relative to the reference case, depending on the electrification case.

The growth in peak winter demand will also require incremental investments in the transmission and distribution systems. While this study includes an estimate for the required incremental investment in transmission capacity, it was beyond the scope of the study to assess the potential requirements for additional electric distribution capacity.

5.3 Cost-Effectiveness of Residential Electrification as a Greenhouse Gas Emissions Reduction Policy

The study of policy-driven electrification of residential fossil fuel heating load (space and water) indicates that the national average cost of U.S. GHG emissions reductions achieved would be between $572 and $806 per metric ton of CO_2 reduced, depending on the power generation case considered. These costs indicate that this policy approach would be a more expensive approach to GHG reductions compared to other options being considered. Figure 5-1 provides a comparison of the estimated cost per ton of GHG emissions reductions for a range of alternative policy options and technologies available for reducing carbon emissions.[29]

Figure 5-1: Comparison of Cost Ranges For GHG Emissions by Reduction Mechanism



Sources: Energy Innovations, Energy Policy Simulator; GHG emission credits from the most recent auction for the Regional Greenhouse Gas Initiative (RGGI) and California Cap & Trade program; GHG reduction costs for the existing coal generation units estimated based on the Levelized Cost of Energy (LCOE) consistent with the EIA's 2017 AEO Base Case; New York Public Service Commission's (NYPSC's) adoption of the Social Cost of Carbon (SCC); U.C. Davis, The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute, 2016; Comparison of Greenhouse Gas Abatement Costs in California's Transportation Sector presented at the Center for Research in Regulated Industries - 27th Annual Western Conference (2014); Maximum cost of $10 per MMBtu for any Demand Side Management (DSM) program costs estimated based on an review of public DSM programs; Carbon Engineering, Keith et al., A Process for Capturing CO_2 from the Atmosphere, Joule (2018), https://doi.org/10.1016/j.joule.2018.05

This illustrative comparison to other GHG reduction measures shows the high relative and absolute cost of policy-driven electrification policies at a national level. The other GHG reduction measures shown for comparison include:

- **Fuel Efficiency Improvements (Transportation Sector):** GHG reduction costs from fuel efficiency standards are generally negative, meaning that they generate both cost savings and GHG reductions. Costs range from -$345 to $5 per metric ton of CO_2 reduction.

- **Power Sector GHG Reduction Credits:** Costs range from $4 to $16 per metric ton of CO_2 reduction based on the 2018 GHG reduction credits in the Regional Greenhouse Gas Initiative (RGGI) and the California Cap & Trade programs.

- **Policy-Driven Retirement of Existing Generation:** The EIA 2017 AEO projects GHG emissions from the generation of electricity supplied to the residential sector to account for about 10 percent of total U.S. GHG emissions in 2035, or more than twice the contribution of the CO_2 emissions from natural gas use in the residential sector in the same year.

These emissions could be reduced at a much lower cost than policy-driven residential electrification by replacing coal generation with natural gas generation. Rreducing CO_2 emissions from the power sector by replacing existing coal generation with a new gas generation combined cycle plant would cost up to about $26 per metric ton of CO_2 reduced.

- **Renewable Natural Gas (RNG):** There are broad ranges of estimates for the cost to capture and deliver RNG to consumers. The upper range of these costs has been as high as $100 per metric ton of CO_2 reductions, although there are RNG volumes available at lower costs.

- **Social Cost of Carbon:** Several states are beginning to consider the use of a social cost of carbon as a means to quantifying the comprehensive estimate of climate change damages in future regulatory planning. New York used a social cost of carbon ranging from $47 to $72 per metric ton of CO_2 reduction based on the year of emissions.

- **Low Carbon Fuel Standard (Transportation Sector):** A low carbon fuel standard is a performance-based standard that provides regulated parties an opportunity to find the most cost-effective compliance mechanism to reduce a fuels carbon intensity, which can result in a broad range of costs for these policies. Costs for these policies can be up to $123 per metric ton of CO_2 reduction.

- **Demand Side Management (Natural Gas Use):**
There are a wide range of DSM measures that natural gas customers can implement to reduce natural gas usage and reduce CO_2 emissions. Many DSM measures can be implemented at below the avoided cost of natural gas, resulting in a negative cost per ton of ton of CO_2 reduction. An upper range on the cost of DSM activity likely to be considered is around $10 per MMBtu above the avoided cost of natural gas, which would correspond to $188 per metric ton of CO_2 reduction.

- **Atmospheric CO_2 Removal:** In June 2018, Joule Magazine published a peer-reviewed study detailing the Carbon Engineering cost estimates for the company's planned large-scale CO_2 removal plant. The company estimates that the costs per metric ton of CO_2 reduction range from $94 to $232 per metric ton of CO_2 reduction, well below prior estimates for this type of technology.

5.4 Applicability of Study Conclusions to Specific Policy Proposals at the State and Local Level

The analysis in this study was focused on broad regional and national markets. However, the residential electrification policy discussion is typically occurring at the state and local level. The study evaluated one set of residential electrification policy options under two alternative approaches to regulating growth in power grid requirements for all states. The policies evaluated here are unlikely to precisely replicate any specific proposed policy option, and there can be a wide variety of permutations of the residential electrification policies under discussion. Different variations of the basic policy will have costs and benefits that are likely to differ from the costs and benefits associated with the scenarios evaluated in this study.

In addition, the costs associated with policy-driven residential electrification can differ widely from the results of this study. For example, the results would differ if the residential electrification policy is implemented on a local or state level rather than the regional and national level as reported in this study.

Natural gas and electricity prices to residential customers, space heating requirements and existing housing stock characteristics can vary widely in different utility service territories even within the same state and region. Hence, the results of this analysis should not be applied or relied on as an indicator of the expected costs and benefits of a specific electrification policy proposal for a specific state or locality. However, the results of the analysis are sufficiently robust to indicate that residential electrification is likely to be a higher cost option for reducing GHG emissions even in areas with stringent renewable power requirements and an expectation of low-emitting future electric grids.

5.5 Other Impacts of Policy Driven Residential Electrification

- **Impact on Natural Gas Distribution System Costs to Other Customers:** Policy-driven electrification of direct-use natural gas from the residential sector would result in a significant decrease in the number of residential customers connected to the natural gas distribution system and in the volume of natural gas throughput on those distribution systems. Payments by residential customers currently support much of the overall natural gas distribution system. While the overall costs incurred by the natural gas distribution system would be expected to decline with the reduction in the number of customers and throughput, the cost reductions would not impact previously incurred costs on the system, which would need to be recovered from the remaining customers. This would result in a material shift in natural gas distribution system costs to the remaining gas utility consumers, including the remaining residential customers, commercial sector, and industrial sector customers. This study did not include an evaluation of these cost implications to consumers.

- **Impact on Electric Distribution System Costs:** While the study includes an assessment of the costs likely to be incurred to meet the growth in electricity demand for generation and transmission assets, the incremental costs not included in current electric rates of expanding the electric distribution system to meeting the increase in load have not been addressed. These costs will differ widely based on the specific locations of the load growth and are difficult to estimate. However, given the estimated increase in peak system requirements nationally, between 10 and 28 percent relative to the Reference Case, these costs are potentially substantial.

- **Impact of Policy-Driven Residential Electrification on Fugitive Methane Emissions:** This study did not include upstream or life-cycle emissions from any of the fuels consumed on site or for electricity generation. Doing so would have required a broader analysis of life-cycle emissions for all fuels through 2050, which was outside the scope of this study. Some studies have included only the upstream emissions of methane associated with on-site gas use. This neglects both the upstream impact on electricity generation and the effect on other fossil fuels. That said, even an assessment of upstream methane emissions has little effect on the net emission reductions calculated in this study. Including upstream methane emissions increases the GHG emissions factor for natural gas for on-site and electricity generation. In the Market-Based Case, net natural gas consumption increases, so including methane emissions reduces the net emissions reductions (including power sector emissions) and increases the cost per ton of reduction.

> In the Renewables-Only Case, the emissions reductions would have been roughly 12 percent to 17 percent greater based on GWP100, reducing the cost per ton of emissions reductions by an equivalent amount. Neither change affects the fundamental conclusions or significantly changes the cost-effectiveness relative to other control options.

5.6 Implications for the Policy Debate on Residential Electrification

The study did not address electrification policies targeted at other sectors of the economy, including the transportation sector, where policy-driven electrification could prove to be a more cost-effective approach to reducing GHG emissions, or market-driven electrification where consumers decide to invest in electric technologies rather than natural gas or other fuels. Overall, the results of this study reflect the scenarios evaluated, the costs considered, and the baseline emissions and energy prices from the EIA 2017 AEO. The analysis indicates that electrification policy measures that require the widespread conversion of residential space heating and water heating applications from natural gas and other fuels to electricity in order to reduce GHG emissions will be challenged by issues including the cost-effectiveness, consumer cost impacts, current and projected electric grid emission levels, and requirements for new investments in the power grid to meet growth in peak generation requirements over the winter periods.

At the same time, the total GHG emissions reductions available from a policy targeting electrification of residential heating loads represent a small fraction of domestic emissions. Total residential natural gas emissions are expected to account for less than 4 percent and total residential fossil fuel emissions are expected to account for less than 6 percent of the estimated 6,200 million metric tons of GHG emissions in 2035 in the AEO 2017 Reference Case. Aggressive electrification policies would have the potential to reduce these emissions by up to 1.5 percent of the total U.S. GHG emissions, at a net cost to energy consumers ranging from $590 million to $1.2 trillion (real 2016 $).

As a result, the conversations surrounding residential electrification policies and other approaches toward a low-carbon economy need to be evaluated in an integrated manner that includes not only the potential emissions reductions, but also considers the feasibility and real-world issues of complying with the proposed policies, as well as the potential consequences of the policies, including the economic impacts on consumers, and potential impacts on the power grid.

Appendix A: Study Inputs and Assumptions

A-1 Natural Gas and Electric Rates

The electric and natural gas prices (Real 2016 $) from the EIA 2017 AEO Base Case are used to calculate the difference in the cost of energy between a gas furnace and electric heat pump based on the equipment's regional performance. The residential natural gas and electricity prices from the EIA AEO are summarized in Exhibits A-1 and A-2 below:

Exhibit A-1: Average U.S. Residential Prices from EIA's 2017 AEO Base Case (Real 2016 $)

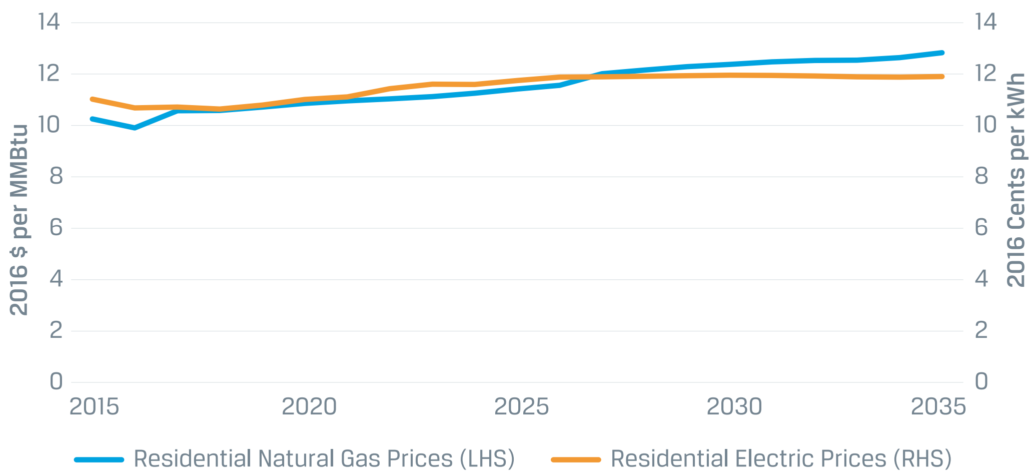


Exhibit A-2: Regional Residential Natural Gas and Electric Rates (Real 2016 $)[1]

	Residential Electric Prices (2016 Cents per kWh)					Residential Natural Gas Prices ($2016 per MMBtu)				
Region	**2016**	**2020**	**2025**	**2030**	**2035**	**2016**	**2020**	**2025**	**2030**	**2035**
East Coast	12.69	14.25	15.89	16.41	16.48	10.15	10.74	11.50	12.12	12.67
Midwest	10.85	11.20	11.98	12.32	12.25	8.46	9.49	9.93	10.62	10.96
New England	15.80	13.61	15.44	16.60	17.27	11.68	12.19	12.91	13.58	14.19
New York	15.90	17.92	20.33	21.16	21.29	11.26	12.06	12.77	13.30	14.08
Plains	10.91	10.47	10.88	10.86	10.85	9.06	10.47	10.77	11.47	11.74
Rockies	9.66	9.46	10.12	10.23	10.62	7.89	8.83	9.39	9.89	10.21
South	9.20	9.90	10.45	10.59	10.49	12.26	13.15	13.95	14.98	15.35
Texas	8.96	9.28	9.80	10.06	9.75	9.47	10.71	10.75	11.48	11.84
West	12.88	12.86	14.22	14.84	15.42	11.01	11.91	12.50	14.84	15.41
U.S. Total	**10.69**	**11.01**	**11.75**	**11.96**	**11.91**	**9.91**	**10.86**	**11.42**	**12.37**	**12.83**

[1] The regional averages are based on a weighted average of the state-level residential prices based on the number of converted natural gas households in each state. The state level residential prices are based on the EIA's 2017 AEO Base Case census division prices, which were used to derive each state's residential rates based on that state's 2016 prices relative to the census division average.

A-2 Impact of Policy-Driven Residential Electrification on Emissions:

Residential and Power Generation Sector Emissions

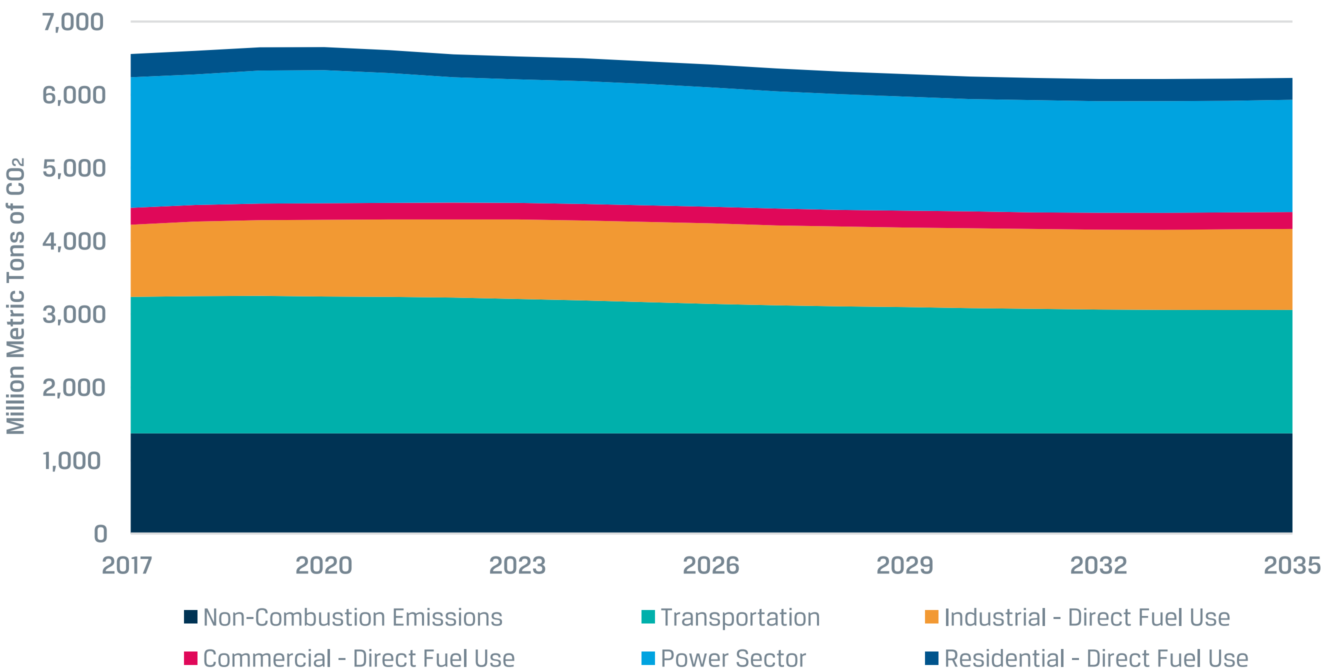
The impact of the residential electrification policies on CO_2 emissions are estimated based on the impact of the residential electrification policies on energy consumption in the residential and power generation sectors relative to the Base Case. The following fuel emissions factors are used to estimate the changes in emissions:[2]

- 117 pounds of CO_2 per Million Btu of natural gas
- 161 pounds of CO_2 per Million Btu of diesel fuel / heating oil
- 139 pounds of CO_2 per Million Btu of propane
- 208 pounds of CO_2 per Million Btu of coal
- 195 pounds of CO_2 per Million Btu of biomass

Other Emission Sources

To estimate the total change in emissions for each region, the study used emissions estimates from the EIA 2017 AEO Base Case for the energy related CO_2 emissions by sector and source and an estimate of 1,370 Million Metric Tons of CO_2 from non-energy related GHG emissions from combustion and non- combustion. This estimate is based on the 2016 reported GHG emission levels from non-combustion sources based on the Environmental Protection Agency's 2016 Inventory of U.S. Greenhouse Gas Emissions and Sinks .[3] Exhibit A-2 shows the total U.S. GHG emissions by emitting sector for the Reference Case from 2017 to 2035.

Exhibit A-3: Reference Case - Total U.S. GHG Emissions by Sector



[2] Source: Energy Information Administration: How much carbon dioxide is produced when different fuels are burned?

[3] https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2016

A-3 Residential Household Conversions to Electricity

The policy-driven residential electrification scenario evaluated in this study reflects a policy implemented in 2023 that requires all new homes to be built with electric space and water heating appliances, and requires the conversion of existing homes with natural gas, propane, or fuel oil space and water heating appliances to electricity at the end of the useful life of the space heating appliance.

In order to determine the consumer costs associated with the conversion to electricity, the housing stock is disaggregated by:

- New household construction
- Households with forced-air furnaces and existing air-conditioning
- Households with forced-air furnaces without existing air-conditioning
- Households with hydronic (Radiator) heating systems – Both with and without existing air-conditioning systems

The number of space heating households converted to electricity between 2023 and 2035 by type of household is shown in Exhibit A-4. The number of space heating households converted to electricity between 2023 and 2035 by region for the Renewables Only Case is shown in Exhibit A-5.

Exhibit A-4: Number of Natural Gas, Fuel Oil, and Propane Households Converted to Electricity from 2023 to 2035 by Type of Heating System (Million Households)

Household Fuel Type	New Households	Forced Air Furnace with A/C	Forced Air Furnace without A/C	Hydronic Heating with A/C	Hydronic Heating without A/C	U.S. Lower 48 Total
Natural Gas	8.6	33.3	1.0	5.5	1.3	49.7
Propane/Fuel Oil	0.0	3.9	0.7	1.6	0.3	6.4
Total Fossil/Fuel Households Subject to Electrification Policy	**8.6**	**37.1**	**1.7**	**7.1**	**1.6**	**56.1**

Exhibit A-5: Number of Natural Gas, Fuel Oil, and Propane Households Converted to Electricity in the "Renewable Generation Only" Case from 2023 to 2035 by Region (Million Households)

Household Fuel Type	East Coast	Midwest	New England	New York	Plains	Rockies	Texas	South	West	U.S. Lower 48
Natural Gas	6.4	10.0	2.0	3.7	5.1	2.2	5.0	3.0	12.3	49.7
Propane/Fuel Oil	1.1	0.8	1.4	1.0	0.7	0.1	0.7	0.2	0.5	6.4
Total Households Converted (2023 to 2035)	**7.5**	**10.8**	**3.3**	**4.8**	**5.8**	**2.3**	**5.7**	**3.2**	**12.8**	**56.1**

A-4 Residential Energy Efficiency and Cost Analysis Assumptions[4]

The number of households converted shown in Exhibits A-4 and A-5 are for the Renewables-Only Case. In the Renewables-Only Case, the residential electrification policy is applied in all regions. In the Market-Based Generation Case, the policy is applied only in regions where the electric grid is expected to be sufficiently clean to reduce overall CO_2 emissions, based on the EIA AEO 2017 Base Case projection of the electric grid. Hence, in this scenario, conversions in the Midwest, Plains, and Rockies are zero due to the lack of emissions reductions. The number of conversions in the other regions is the same in both scenarios.

Different conversion costs are estimated for each of the following household heating types:

- New household construction
- Households with forced-air furnaces and existing air-conditioning
- Households with forced-air furnaces without existing air-conditioning
- Households with hydronic (radiator) heating systems – Both with and without existing air-conditioning systems

A typical 2,250 square foot household is used as the baseline for estimating the conversion cost differences between a fossil-fuel heated and electric-heated households. All households are assumed to be single-family households. Other types of residential housing (duplexes, manufactured homes, and large residential housing, etc.) are treated as single-family homes to simplify the analysis, given the wide range of cost uncertainties in converting non-single family homes.

- The equipment and energy cost comparisons for all new construction households and existing households converting to electricity include a fossil-fuel furnace and an electric air conditioning system.
- A real discount rate of 5 percent is used in the economic analysis between systems.

Existing natural gas, propane and fuel oil space heating systems:

- The average efficiency of the existing furnaces being replaced: 80%

New natural gas, propane, and fuel oil space heating systems:

- New furnace costs are based on a 90,000 BTU per Hour High-Efficiency Energy Star® rated system.

[4] All costs are presented in real 2016 $, unless otherwise specified.

- New furnace efficiency – Same as existing furnace efficiency to ensure that the analysis does not overstate potential gas furnace efficiency, or understate furnace installation costs.
- Expected equipment life of 24 years
- Annual non-energy operating costs of $75 (Real 2016 $)
- A/C System - Seasonal Energy Efficiency Ratio (SEER) = 15

New electric space heating system:

- Average HSPF of 11.5 for all new systems installed between 2023 and 2035.
- Heat Pump equipment prices are based on the cost of a typical 3 Ton 9.5 HSPF System in 2016 – We assume that average efficiency improves without increasing system costs in real 2016$ through 2035. The increase in costs associated with higher efficiency units is offset by improvements in technology and economies to scale. The full impact of improvements in technology and economies to scale are assumed to be reflected in improvements in efficiency, rather than reductions in costs.
- Expected equipment life of 18 years.
- Annual non-energy operating costs of $75 (real 2016 $).

Exhibit A-6: National Installation Costs and Annual Fuel Costs (2035) by Household Heating & Cooling System Type

Household Heating & Cooling System Type	New Household		Replacement - Gas Furnace & A/C unit	Conversion of Forced Air Furnace		Conversion of Hydronic System	
	Gas Furnace & A/C	ASHP	Gas Furnace & A/C	ASHP (Existing A/C)	ASHP (No Existing A/C)	ASHP (Existing A/C)	ASHP (No Existing A/C)
Purchase Cost (Capital)	$4,495	$3,903	$4,495	$4,065	$4,065	$4,065	$4,065
Total Installation & Upgrade Costs (1-Year Cost)	$6,281	$5,991	$6,858	$6,993	$10,909	$8,637	$11,509
Annual Equipment Costs[1]	$337	$408	$361	$464	$681	$555	$714
Annual Heating Expense[1]	$998	$1,475	$998	$1,475	$1,475	$1,475	$1,475
Total Annualized Costs	**$1,335**	**$1,883**	**$1,359**	**$1,939**	**$2,156**	**$2,030**	**$2,189**

Source: Derived from national level and state level estimates for installation costs from a variety of sources, including homewyse. com, homeadvisor.com, energyhomes.org, HomeDepot.com, homesteady.com, and manufacture reported retail sales prices for home heating equipment.

[1] Equipment costs are annualized over the expected life of the equipment, using a real discount rate of 5%.

The study uses the household capital cost differences in Exhibit A-6 in the calculation of each region's consumer capital and investment cost impacts. These costs are based on the national average household costs for each system type and heating fuel (Natural Gas & Electric) with a regional cost factor to capture differences in installation and equipment costs between regions.

Water Heating Equipment

The study uses average costs for currently available high efficiency water heating equipment with a 50-gallon tank storage, placed indoors, with no regional variation in water heater efficiency factors. Fuel oil and propane water heating households are treated as if natural gas households.

Natural gas water heating system:

- The replacement natural gas water heater is sized at 42,000 Btu output with an energy efficiency rating of 80 percent.
- Natural gas water heater equipment cost is $1,392, with an expected life of 10 years, with installation costs of $540.

Electric heat pump water heating system:

- Electric heat pump water heater equipment cost is $1,651, with an expected life of 10 years, and installation costs of $520.

A-5 Heating and Cooling System Efficiency Assumptions

Space Heating Efficiency

The study uses a high-efficiency conventional air source heat pump as the electric alternative to fossil fuel space heating equipment throughout the analysis. Heating efficiency for air-source electric heat pumps is indicated by the HSPF, which is the total space heating required during the heating season, expressed in Btu, divided by the total electrical energy consumed by the heat pump system during the same season, expressed in watt-hours.

Electric Heat Pump Heating Efficiency Assumptions

This analysis starts with an Air Source Heat Pump with a reported HSPF of 11.0 in 2023. The efficiency of the average newly installed heat pump is assumed to increase by about 1 percent per year, reaching an HSPF of 12.5 by 2035. This results in an average reported HSPF of 11.5 (COP of 3.4) for the heat pumps used to replace the furnaces converted to electricity due to the residential electrification policy over the time period from 2023 through 2035.

Impact of Weather on Heating System Efficiencies

Actual heat pump performance is highly dependent on the weather conditions (temperature) when the heat pump is operating. To account for the variations in effective performance of electric ASHPs across the different regions, this study adjusts efficiency ratings for the newly installed electric heat pumps for each state based on actual temperature data.

The study uses weather data from 220 different regional weather stations to estimate the weighted average ASHRAE heating season Design Temperature for each state. The seasonal design temperature, based on a consumption weighted annual temperature average for each state, is used to estimate the actual average heating season efficiency of the ASHP for each state.

The study's effective performance ratings for the electric ASHPs are derived based on research from the Florida Solar Energy Center.[5] In addition, the study bases the heat pump performance on manufacturer's performance ratings at select temperature ranges.[6]

The average weather-adjusted effective COP is based on local winter weather conditions from 220 weather reporting regions aggregated to the state level. When adjusted for actual expected weather conditions, the heat pumps installed between 2023 and 2035 are expected to achieve an average weather-adjusted effective COP of 2.6 in the Renewables-Only Case and 2.9 in the Market-Based Generation Case.[7]

At temperatures below 4 degrees Fahrenheit, the study assumes that ASHPs switch-over to electric resistance heating, which has an efficiency of 100 percent, or a COP of 1.

Electric Water Heater Efficiency

The water heater conversions from natural gas to electric demand are based on an electric heat pump water heater with an average efficiency of 200 percent, applied in a uniform manner across all regions.

Air Conditioning

Installation of a heat pump provides both heating and air conditioning. In this study, all gas furnace replacements are paired with an air conditioner when evaluating equipment and operating costs between the different equipment options. The efficiency of the air conditioner used is assumed to be equivalent to the efficiency of the heat pump for cooling load, hence air conditioning load did not impact the incremental operating costs between the different equipment options.

[5] Fairey, P., D.S. Parker, B. Wilcox and M. Lombardi, "Climate Impacts on Heating Seasonal Performance Factor (HSPF) and Seasonal Energy Efficiency Ratio (SEER) for Air Source Heat Pumps." ASHRAE Transactions, American Society of Heating, Refrigerating and Air Conditioning Engineers, Inc., Atlanta, GA, June 2004.

[6] These performance profiles for ASHPs were selected from currently available electric ASHPs on the market rated with performance rating of 10.5 HSPF

[7] The Market-Based case excludes regions where electrification would increase GHG emissions based on the expected grid emissions. This included the Plains and Rockies regions where colder temperatures reduce the effective efficiency of the heat pumps.

A-6 Impact of Conversion to Electricity on Peak and Annual Electricity Demand

The impact on peak and heating season electricity demand resulting from the conversion of residential fossil-fuel space and water heating consumption of natural gas, fuel oil and propane to electricity is estimated by converting the fossil fuel consumption from the converted households to the electricity demand based on the electricity that would be needed to replace the end-use energy provided by the existing space and water heating applications, accounting for the differences in efficiency of the different applications, and the difference in heating season efficiency and peak period efficiency for the ASHPs.

- Residential household energy consumption information from the 2015 EIA Residential Energy Consumption Survey (RECS) is used to segment household usage between space heating, water heating and other use. This is done for each census region and allocated to each state based on 2016 state data.

- 2015 RECS data is used to determine residential fossil fuel consumption by fuel type and end-use demand type.
(Space Water, Water Heating, and Other). A monthly consumption profile is created using RECs information and monthly natural gas deliveries to residential consumers by state from the EIA.

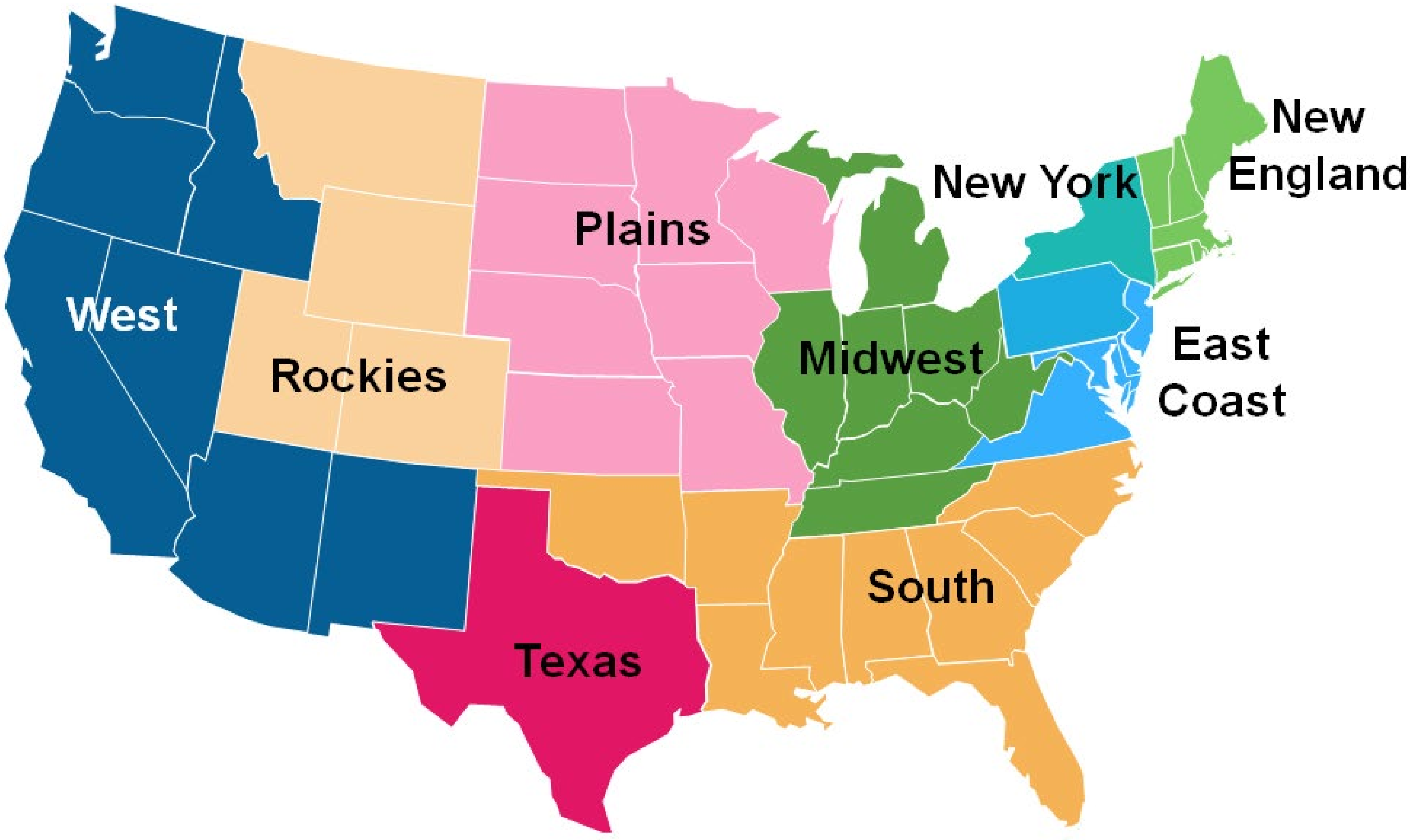
- The peak day design sendout for water and gas heating load is created in order to estimate peak winter period electric demand impacts of converting residential households to electricity. To calculate the peak day natural gas demand levels, the study uses Heating Degree Days (HDDs) from the coldest day from 1986 to 2016 from 220 locations to estimate the HDDs for each state based on weighted state-wide average of the number of natural gas households.

- The average space heating consumption (BTU) per Household and per HDD is calculated for the winter months (December to February) for the past 10-years. The study then uses this ratio to calculate the 2035 residential space heating sendout based on the HDDs from the coldest day from 1986 to 2016 and the number of natural gas households.

- The average monthly consumption per household is then calculated for water heating and other demand for natural gas. This ratio is used to create the 2035 residential water heating and other demand projections based on the number of natural gas households and consumption patterns by region sourced from the EIA RECS.

Appendix B: Regional Results

Exhibit B-1 Study Regions



B-1 East Coast

Exhibit B-2 East Coast Regional Generation and Capacity

Generation Type	2016	2035 Generation (GWh)				2016	2035 Capacity (MW)		
		Reference Case	Renewables-Only	Market-Based Generation			Reference Case	Renewables-Only	Market-Based Generation
Existing Units	**423,159**	**446,559**	**486,686**	**434,777**		**101,927**	**93,818**	**106,800**	**98,096**
Coal	76,433	52,589	34,761	38,436		21,755	8,987	13,258	10,275
Nuclear	151,839	129,846	129,846	129,846		19,189	16,409	16,409	16,409
Natural Gas	162,332	238,560	295,657	241,035		39,663	54,611	54,611	54,611
Wind & Solar	4,906	5,683	5,683	5,683		2,310	2,678	2,678	2,678
Other Renewables	13,819	14,922	13,161	14,781		7,949	8,119	8,120	8,119
Oil/Gas & Other	13,829	4,960	7,579	4,997		11,060	3,013	11,724	6,003
New Units	**0**	**30,197**	**43,980**	**71,653**		**0**	**9,132**	**28,252**	**21,042**
Natural Gas	0	16,536	19,409	57,721		0	2,994	2,994	14,741
Wind & Solar	0	13,661	20,679	13,933		0	6,139	9,328	6,302
Energy Storage	0	0	3,892	0		0	0	15930.0503	0
East Coast Total	**423,159**	**476,756**	**530,666**	**506,431**		**101,927**	**102,950**	**135,053**	**119,138**

Exhibit B-3. East Coast Regional Results

Region	Consumer Direct-Use Natural Gas Use	Power Sector Natural Gas Use	Change in Natural Gas Use	Cumulative Household CO_2 Emissions (Natural Gas, Propane, and Fuel Oil)	Cumulative Power Sector CO_2 Emissions	Cumulative Total Change in CO_2 Emissions	Cost of Emissions Reduction (Discounted to 2023)
Units	Tcf from 2023 to 2050 (Not Discounted)			Million Metric Tons of CO_2 from 2023 to 2050 (Non-Discounted)			2016 $ per Metric Ton of CO_2
Reference Case	17.3	50.2	N/A	1,253.7	4,786	N/A	N/A
Renewables-Only Case	9.7	56.3	-1.5	715.6	5,091	-223	635
Market-Based Generation Case	9.7	62.5	4.7	715.6	4,840	-380	391

Region	Coincident Peak Electric Generation Requirement in 2035 (Space & Water Heating)	Incremental Electric Consumption Levels in 2035 (Space & Water Heating)				
	Maximum Hourly Peak Generation (GW)	Average Winter Day (November - April) (GW)	Normal Day June 2035 (GW)	2035 Annual Electric Consumption (GWh)	January 2035 Electric Consumption (GWh)	June 2035 Electric Consumption (GWh)
Renewables-Only Case	86.1	15.1	2.8	61,899	13,629	1,058
Market-Based Generation Case	86.1	15.1	2.8	61,899	13,629	1,058

Sector Description	Units	Base Case	Change from Base Case	
			Renewables-Only	Market-Based Generation
Consumer Energy Purchases	2016 $ Billions	148.2	86.1	86.1
Consumer Capital Costs		475.2	21.7	21.7
Power Sector Capital Costs		16.4	22.5	12.2
Transmission Capital Costs		N/A	8.7	4.7
Total Costs		639.8	138.9	124.7
Pre-Electrification: Average Household Annual Household Energy Costs	2016 $ per Household	2,178	N/A	N/A
Cumulative Change in Costs Per Converted Household		N/A	17,600	16,550
Annualized Change in Costs Per Converted Household		N/A	1,200	1,110

B-2 Midwest

Exhibit B-4. Midwest Regional Generation and Capacity

Generation Type	2016	2035 Generation (GWh)				2016	2035 Capacity (MW)		
		Reference Case	Renewables-Only	Market-Based Generation			Reference Case	Renewables-Only	Market-Based Generation
Existing Units	**730,975**	**698,035**	**755,301**	**690,846**		**184,214**	**153,361**	**174,483**	**152,879**
Coal	420,221	356,793	355,665	350,739		87,560	50,951	66,726	50,772
Nuclear	168,344	147,173	147,173	147,173		22,210	18,599	18,599	18,599
Natural Gas	95,416	136,081	187,934	136,431		51,633	59,471	59,816	59,334
Wind & Solar	21,650	27,086	27,086	27,086		8,679	10,800	10,800	10,800
Other Renewables*	22,775	27,585	32,277	26,099		8,815	9,481	10,664	9,315
Oil/Gas & Other	2,569	3,317	5,166	3,317		5,317	4,060	7,878	4,060
New Units	**0**	**55,050**	**73,215**	**77,658**		**0**	**21,247**	**53,772**	**24,858**
Natural Gas	0	9,561	10,255	32,169		0	1,389	1,389	5,001
Wind & Solar	0	45,489	56,495	45,489		0	19,857	23,661	19,857
Energy Storage	0	0	6,465	0		0	0	28,721	0
Midwest Total	**730,975**	**753,085**	**828,516**	**768,504**		**184,214**	**174,608**	**228,255**	**177,737**

Exhibit B-5 Midwest Regional Results

Region	Consumer Direct-Use Natural Gas Use	Power Sector Natural Gas Use	Change in Natural Gas Use	Cumulative Household CO_2 Emissions (Natural Gas, Propane, and Fuel Oil)	Cumulative Power Sector CO_2 Emissions	Cumulative Total Change in CO_2 Emissions	Cost of Emissions Reduction (Discounted to 2023)
Units	Tcf from 2023 to 2050 (Non-Discounted)			Million Metric Tons of CO_2 from 2023 to 2050 (Non-Discounted)			2016 $ per Metric Ton of CO_2
Reference Case	32.3	28.8	N/A	1,962	12,278	N/A	N/A
Renewables-Only Case	17.9	32.1	-11.2	1,091	13,090	-38	N/A
Market-Based Generation Case	32.3	40.0	11.1	1,962	12,379	Not Modelled	Not Modelled

Region	Coincident Peak Electric Generation Requirement in 2035 (Space & Water Heating)			Incremental Electric Consumption Levels in 2035 (Space & Water Heating)		
	Maximum Hourly Peak Generation (GW)	Average Winter Day (November - April) (GW)	Normal Day June 2035 (GW)	2035 Annual Electric Consumption (GWh)	January 2035 Electric Consumption (GWh)	June 2035 Electric Consumption (GWh)
Renewables-Only Case	133.5	32.9	4.8	132,856	29,400	1,425
Market-Based Generation Case	N/A	N/A	N/A	N/A	N/A	N/A

Sector Description	Units	Base Case	Change from Base Case	
			Renewables-Only	Market-Based Generation
Consumer Energy Purchases	2016 $ Billions	207.9	193	N/A
Consumer Capital Costs		215.6	24.8	N/A
Power Sector Capital Costs		7.8	47.5	N/A
Transmission Capital Costs		N/A	13.5	N/A
Total Costs		865.9	278.8	N/A
Pre-Electrification: Average Household Annual Household Energy Costs	2016 $ per Household	1,997	N/A	N/A
Cumulative Change in Costs Per Converted Household		N/A	25,920	N/A
Annualized Change in Costs Per Converted Household		N/A	1,740	N/A

B-3 New England

Exhibit B-6 New England Regional Generation and Capacity

Generation Type	2016	2035 Generation (GWh)				2016	2035 Capacity (MW)		
		Reference Case	Renewables-Only	Market-Based Generation			Reference Case	Renewables-Only	Market-Based Generation
Existing Units	**104,928**	**87,114**	**119,073**	**85,039**		**32,344**	**28,769**	**33,779**	**33,345**
Coal	864	0	0	0		1,986	0	0	0
Nuclear	31,795	26,870	26,870	26,870		4,018	3,396	3,396	3,396
Natural Gas	55,127	38,246	69,451	34,423		14,871	17,946	17,946	17,946
Wind & Solar	2,927	4,603	4,603	4,603		1,355	2,181	2,181	2,181
Other Renewables	13,234	17,007	17,759	18,754		4,767	5,162	5,323	5,446
Oil/Gas & Other	982	389	389	389		5,347	84	4,933	4,376
New Units	**0**	**12,912**	**24,616**	**45,192**		**0**	**3,512**	**36,909**	**34,651**
Natural Gas	0	0	0	29,035		0	0	0	30,075
Wind & Solar	0	12,912	21,835	16,157		0	3,512	6,531	4,576
Energy Storage	0	0	2,781	0		0	0	30,378	0
New England Total	**104,928**	**100,026**	**143,689**	**130,230**		**32,344**	**32,281**	**70,688**	**67,996**

Exhibit B-7 New England Regional Results

Region	Consumer Direct-Use Natural Gas Use	Power Sector Natural Gas Use	Change in Natural Gas Use	Cumulative Household CO_2 Emissions (Natural Gas, Propane, and Fuel Oil)	Cumulative Power Sector CO_2 Emissions	Cumulative Total Change in CO_2 Emissions	Cost of Emissions Reduction (Discounted to 2023)
Units	Tcf from 2023 to 2050 (Non-Discounted)			Million Metric Tons of CO_2 from 2023 to 2050 (Non-Discounted)			2016 $ per Metric Ton of CO_2
Reference Case	5.7	8.2	N/A	652.7	702	N/A	N/A
Renewables-Only Case	3.1	12.0	12.5	367.3	1,023	57	N/A
Market-Based Generation Case	3.1	13.7	14.3	367.3	926	-56	1,081

Region	Coincident Peak Electric Generation Requirement in 2035 (Space & Water Heating)			Incremental Electric Consumption Levels in 2035 (Space & Water Heating)		
	Maximum Hourly Peak Generation (GW)	Average Winter Day (November - April) (GW)	Normal Day June 2035 (GW)	2035 Annual Electric Consumption (GWh)	January 2035 Electric Consumption (GWh)	June 2035 Electric Consumption (GWh)
Renewables-Only Case	52.5	13.6	2.7	55,811	11,290	789
Market-Based Generation Case	52.5	13.6	2.7	55,811	11,290	789

Sector Description	Units	Base Case	Change from Base Case	
			Renewables-Only	Market-Based Generation
Consumer Energy Purchases	2016 $ Billions	80.9	66.2	66.2
Consumer Capital Costs		200.2	11	11
Power Sector Capital Costs		22.6	48.6	29.9
Transmission Capital Costs		N/A	11.8	10.9
Total Costs		303.7	137.7	118.1
Pre-Electrification: Average Household Annual Household Energy Costs	2016 $ per Household	2,373	N/A	N/A
Cumulative Change in Costs Per Converted Household		N/A	41,210	35,340
Annualized Change in Costs Per Converted Household		N/A	2,770	2,370

B-4 New York

Exhibit B-8 New York Regional Generation and Capacity

Generation Type	2016	2035 Generation (GWh)				2016	2035 Capacity (MW)		
		Reference Case	Renewables-Only	Market-Based Generation			Reference Case	Renewables-Only	Market-Based Generation
Existing Units	**128,091**	**109,245**	**130,810**	**96,334**		**39,570**	**35,861**	**41,019**	**40,714**
Coal	449	2,657	3,031	1,203		2,246	897	1,562	1,260
Nuclear	42,711	38,844	37,095	32,662		5,398	4,909	4,909	4,909
Natural Gas	40,907	29,711	48,838	23,144		13,213	14,959	14,992	14,992
Wind & Solar	4,046	4,624	4,624	4,624		1,978	2,260	2,260	2,260
Other Renewables	28,583	29,939	32,415	31,231		6,251	6,411	6,803	6,623
Oil/Gas & Other	11,395	3,470	4,807	3,470		10,484	6,425	10,494	10,671
New Units	**0**	**35,601**	**60,937**	**106,526**		**0**	**12,149**	**46,712**	**49,458**
Natural Gas	0	0	1	47,007		0	0	0	28,990
Wind & Solar	0	35,601	58,208	59,519		0	12,149	20,500	20,468
Energy Storage	0	0	2,728	0		0	0	26,212	0
New York Total	**128,091**	**144,846**	**191,747**	**202,860**		**39,570**	**48,010**	**87,732**	**90,173**

Exhibit B-9 New York Regional Results

Region	Consumer Direct-Use Natural Gas Use	Power Sector Natural Gas Use	Change in Natural Gas Use	Cumulative Household CO_2 Emissions (Natural Gas, Propane, and Fuel Oil)	Cumulative Power Sector CO_2 Emissions	Cumulative Total Change in CO_2 Emissions	Cost of Emissions Reduction (Discounted to 2023)
Units	Tcf from 2023 to 2050 (Non-Discounted)			Million Metric Tons of CO_2 from 2023 to 2050 (Non-Discounted)			2016 $ per Metric Ton of CO_2
Reference Case	11.2	7.3	N/A	796.2	567	N/A	N/A
Renewables-Only Case	6.1	13.3	0.9	445.2	869	-23	8,784
Market-Based Generation Case	6.1	11.3	-1.2	445.2	902	-31	6,450

Region	Coincident Peak Electric Generation Requirement in 2035 (Space & Water Heating)			Incremental Electric Consumption Levels in 2035 (Space & Water Heating)		
	Maximum Hourly Peak Generation (GW)	Average Winter Day (November – April) (GW)	Normal Day June 2035 (GW)	2035 Annual Electric Consumption (GWh)	January 2035 Electric Consumption (GWh)	June 2035 Electric Consumption (GWh)
Renewables-Only Case	45.4	8.0	1.9	34,118	6,662	663
Market-Based Generation Case	45.4	8.0	1.9	34,118	6,662	663

Sector Description	Units	Base Case	Change from Base Case	
			Renewables-Only	Market-Based Generation
Consumer Energy Purchases	2016 $ Billions	105.4	186.7	186.7
Consumer Capital Costs		307.3	15.2	15.2
Power Sector Capital Costs		3.5	59.5	56.3
Transmission Capital Costs		N/A	18.3	17.6
Total Costs		416.2	279.6	275.7
Pre-Electrification: Average Household Annual Household Energy Costs	2016 $ per Household	2,252	N/A	N/A
Cumulative Change in Costs Per Converted Household		N/A	58,580	57,770
Annualized Change in Costs Per Converted Household		N/A	3,930	3,880

B-5 Plains

Exhibit B-10 Plains Regional Generation and Capacity

Generation Type	2016	2035 Generation (GWh)				2016	2035 Capacity (MW)		
		Reference Case	Renewables-Only	Market-Based Generation			Reference Case	Renewables-Only	Market-Based Generation
Existing Units	**378,755**	**349,520**	**336,415**	**346,296**		**107,212**	**94,203**	**104,650**	**93,884**
Coal	194,284	156,029	133,210	153,405		41,690	25,665	31,448	25,371
Nuclear	51,906	41,077	41,077	41,077		6,560	5,191	5,191	5,191
Natural Gas	52,528	56,431	62,558	56,073		29,476	31,529	31,529	31,529
Wind & Solar	61,867	75,913	75,913	75,913		20,200	24,245	24,245	24,245
Other Renewables	15,273	18,217	21,674	17,976		4,983	5,551	5,965	5,472
Oil/Gas & Other	2,897	1,853	1,982	1,853		4,303	2,023	6,272	2,076
New Units	**0**	**36,823**	**112,398**	**44,859**		**0**	**8,259**	**54,763**	**9,932**
Natural Gas	0	9,506	10,193	13,512		0	1,425	1,425	2,151
Wind & Solar	0	27,317	98,450	31,347		0	6,834	23,614	7,781
Energy Storage	0	0	3,755	0		0	0	29,724	0
Plains Total	**378,755**	**386,343**	**448,813**	**391,155**		**107,212**	**102,461**	**159,412**	**103,815**

Exhibit B-11 Plains Regional Results

Region	Consumer Direct-Use Natural Gas Use	Power Sector Natural Gas Use	Change in Natural Gas Use	Cumulative Household CO_2 Emissions (Natural Gas, Propane, and Fuel Oil)	Cumulative Power Sector CO_2 Emissions	Cumulative Total Change in CO_2 Emissions	Cost of Emissions Reduction (Discounted to 2023)
Units	Tcf from 2023 to 2050 (Non-Discounted)			Million Metric Tons of CO_2 from 2023 to 2050 (Non-Discounted)			2016 $ per Metric Ton of CO_2
Reference Case	15.0	12.3	N/A	1,011	5,856	N/A	N/A
Renewables-Only Case	8.0	12.8	-6.5	548.6	5,367	-951	230
Market-Based Generation Case	15.0	13.7	1.4	1,011	5,826	Not Modelled	Not Modelled

Region	Coincident Peak Electric Generation Requirement in 2035 (Space & Water Heating)			Incremental Electric Consumption Levels in 2035 (Space & Water Heating)		
	Maximum Hourly Peak Generation (GW)	Average Winter Day (November - April) (GW)	Normal Day June 2035 (GW)	2035 Annual Electric Consumption (GWh)	January 2035 Electric Consumption (GWh)	June 2035 Electric Consumption (GWh)
Renewables-Only Case	60.7	16.9	2.6	68,594	15,331	831
Market-Based Generation Case	N/A	N/A	N/A	N/A	N/A	N/A

Sector Description	Units	Base Case	Change from Base Case	
			Renewables-Only	Market-Based Generation
Consumer Energy Purchases	2016 $ Billions	112.0	78.4	N/A
Consumer Capital Costs		334	13.1	N/A
Power Sector Capital Costs		0.7	64.9	N/A
Transmission Capital Costs		N/A	11.2	N/A
Total Costs		446.7	167.5	N/A
Pre-Electrification: Average Household Annual Household Energy Costs	2016 $ per Household	1,867	N/A	N/A
Cumulative Change in Costs Per Converted Household		N/A	29,120	N/A
Annualized Change in Costs Per Converted Household		N/A	1,950	N/A

B-6 Rockies

Exhibit B-12 Rockies Regional Generation and Capacity

Generation Type	2016	2035 Generation (GWh)				2016	2035 Capacity (MW)		
		Reference Case	Renewables-Only	Market-Based Generation			Reference Case	Renewables-Only	Market-Based Generation
Existing Units	**423,159**	**446,559**	**486,686**	**434,777**		**38,881**	**35,254**	**38,311**	**35,259**
Coal	76,433	52,589	34,761	38,436		18,444	12,764	15,069	12,742
Nuclear	151,839	129,846	129,846	129,846		0	0	0	0
Natural Gas	162,332	238,560	295,657	241,035		9,481	9,551	9,551	9,551
Wind & Solar	4,906	5,683	5,683	5,683		5,930	8,109	8,109	8,109
Other Renewables	13,819	14,922	13,161	14,781		4,698	4,824	4,851	4,851
Oil/Gas & Other	13,829	4,960	7,579	4,997		328	6	731	6
New Units	**0**	**30,197**	**43,980**	**71,653**		**0**	**3,490**	**17,182**	**3,445**
Natural Gas	0	16,536	19,409	57,721		0	0	0	48
Wind & Solar	0	13,661	20,679	13,933		0	3,490	7,489	3,396
Energy Storage	0	0	3,892	0		0	0	9,694	0
Rockies Total	**423,159**	**476,756**	**530,666**	**506,431**		**38,881**	**38,744**	**55,494**	**38,704**

Exhibit B-13 Rockies Regional Results

Region	Consumer Direct-Use Natural Gas Use	Power Sector Natural Gas Use	Change in Natural Gas Use	Cumulative Household CO_2 Emissions (Natural Gas, Propane, and Fuel Oil)	Cumulative Power Sector CO_2 Emissions	Cumulative Total Change in CO_2 Emissions	Cost of Emissions Reduction (Discounted to 2023)
Units	Tcf from 2023 to 2050 (Non-Discounted)			Million Metric Tons of CO_2 from 2023 to 2050 (Non-Discounted)			2016 $ per Metric Ton of CO_2
Reference Case	7.2	3.7	N/A	434.3	3,009	N/A	N/A
Renewables-Only Case	4.3	3.9	-2.7	261.3	3,063	-119	794
Market-Based Generation Case	7.2	4.1	0.4	434.3	2,982	Not Modelled	Not Modelled

Region	Coincident Peak Electric Generation Requirement in 2035 (Space & Water Heating)			Incremental Electric Consumption Levels in 2035 (Space & Water Heating)		
	Maximum Hourly Peak Generation (GW)	Average Winter Day (November - April) (GW)	Normal Day June 2035 (GW)	2035 Annual Electric Consumption (GWh)	January 2035 Electric Consumption (GWh)	June 2035 Electric Consumption (GWh)
Renewables-Only Case	25.8	7.2	1.4	30,840	5,926	430
Market-Based Generation Case	N/A	N/A	N/A	N/A	N/A	N/A

Sector Description	Units	Base Case	Change from Base Case	
			Renewables-Only	Market-Based Generation
Consumer Energy Purchases	2016 $ Billions	42.7	30.1	N/A
Consumer Capital Costs		117.5	4.9	N/A
Power Sector Capital Costs		26.6	18.3	N/A
Transmission Capital Costs		N/A	4	N/A
Total Costs		186.8	57.3	N/A
Pre-Electrification: Average Household Annual Household Energy Costs	2016 $ per Household	1,577	N/A	N/A
Cumulative Change in Costs Per Converted Household		N/A	25,060	N/A
Annualized Change in Costs Per Converted Household		N/A	1,680	N/A

B-7 South

Exhibit B-14 South Regional Generation

Generation Type	2016	2035 Generation (GWh)				2016	2035 Capacity (MW)		
		Reference Case	Renewables-Only	Market-Based Generation			Reference Case	Renewables-Only	Market-Based Generation
Existing Units	**1,021,072**	**996,577**	**1,012,688**	**943,877**		**249,599**	**228,274**	**248,598**	**229,662**
Coal	208,336	187,857	165,784	158,801		59,150	31,382	37,191	30,273
Nuclear	232,893	250,839	250,839	250,839		29,432	31,755	31,755	31,755
Natural Gas	490,144	466,048	506,168	443,383		114,184	119,539	119,539	119,539
Wind & Solar	22,424	42,630	42,630	42,630		8,777	17,196	17,196	17,196
Other Renewables	36,617	37,422	35,525	36,643		17,066	17,328	17,588	17,328
Oil/Gas & Other	30,658	11,782	11,743	11,581		20,991	11,074	25,330	13,571
New Units	**0**	**155,836**	**278,687**	**243,009**		**0**	**40,049**	**77,286**	**54,478**
Natural Gas	0	85,886	88,012	173,060		0	13,830	13,830	28,259
Wind & Solar	0	69,950	180,400	69,950		0	26,219	53,422	26,219
Energy Storage	0	0	10,275	0		0	0	10,034	0
South Total	**1,021,072**	**1,152,413**	**1,291,375**	**1,186,886**		**249,599**	**268,322**	**325,884**	**284,140**

Exhibit B-15 South Regional Results

Region	Consumer Direct-Use Natural Gas Use	Power Sector Natural Gas Use	Change in Natural Gas Use	Cumulative Household CO_2 Emissions (Natural Gas, Propane, and Fuel Oil)	Cumulative Power Sector CO_2 Emissions	Cumulative Total Change in CO_2 Emissions	Cost of Emissions Reduction (Discounted to 2023)
Units	Tcf from 2023 to 2050 (Non-Discounted)			Million Metric Tons of CO_2 from 2023 to 2050 (Non-Discounted)			2016 $ per Metric Ton of CO_2
Reference Case	12.2	106.8	N/A	752.9	12,341	N/A	N/A
Renewables-Only Case	7.3	115.9	4.3	450.0	12,320	-324	218
Market-Based Generation Case	7.3	114.8	3.1	450.0	12,233	-431	63

Region	Coincident Peak Electric Generation Requirement in 2035 (Space & Water Heating)			Incremental Electric Consumption Levels in 2035 (Space & Water Heating)		
	Maximum Hourly Peak Generation (GW)	Average Winter Day (November - April) (GW)	Normal Day June 2035 (GW)	2035 Annual Electric Consumption (GWh)	January 2035 Electric Consumption (GWh)	June 2035 Electric Consumption (GWh)
Renewables-Only Case	24.5	4.3	1.4	18,815	4,039	529
Market-Based Generation Case	24.5	4.3	1.4	18,815	4,039	529

Sector Description	Units	Base Case	Change from Base Case	
			Renewables-Only	Market-Based Generation
Consumer Energy Purchases	2016 $ Billions	110.6	-28.2	-28.2
Consumer Capital Costs		322.4	12.3	12.3
Power Sector Capital Costs		9.5	46.4	14.9
Transmission Capital Costs		N/A	14.1	4.7
Total Costs		442.4	44.6	3.7
Pre-Electrification: Average Household Annual Household Energy Costs	2016 $ per Household	2,116	N/A	N/A
Cumulative Change in Costs Per Converted Household		N/A	7,820	650
Annualized Change in Costs Per Converted Household		N/A	520	40

B-8 Texas

Exhibit B-16 Texas Regional Generation and Capacity

Generation Type	2016	2035 Generation (GWh)				2016	2035 Capacity (MW)		
		Reference Case	Renewables-Only	Market-Based Generation			Reference Case	Renewables-Only	Market-Based Generation
Existing Units	**397,338**	**421,880**	**422,276**	**425,839**		**111,309**	**118,662**	**118,663**	**118,755**
Coal	77,212	88,965	84,860	87,209		22,998	18,531	18,638	18,319
Nuclear	39,249	41,369	41,369	41,369		4,960	5,228	5,228	5,228
Natural Gas	199,368	196,711	202,186	202,929		43,772	47,247	47,247	47,247
Wind & Solar	58,503	83,382	83,382	83,382		21,272	29,321	29,321	29,321
Other Renewables	2,289	3,140	3,130	3,142		1,043	1,091	1,091	1,091
Oil/Gas & Other	20,718	8,313	7,348	7,808		17,263	17,243	17,137	17,548
New Units	**0**	**45,484**	**46,994**	**47,725**		**0**	**17,391**	**17,999**	**17,459**
Natural Gas	0	39,465	40,122	41,707		0	16,018	16,018	16,086
Wind & Solar	0	6,018	5,968	6,018		0	1,373	1,362	1,373
Energy Storage	0	0	905	0		0	0	620	0
Texas Total	**397,338**	**467,364**	**469,270**	**473,564**		**111,309**	**136,053**	**136,662**	**136,215**

Exhibit B-17 Texas Regional Results

Region	Consumer Direct-Use Natural Gas Use	Power Sector Natural Gas Use	Change in Natural Gas Use	Cumulative Household CO_2 Emissions (Natural Gas, Propane, and Fuel Oil)	Cumulative Power Sector CO_2 Emissions	Cumulative Total Change in CO_2 Emissions	Cost of Emissions Reduction (Discounted to 2023)
Units	Tcf from 2023 to 2050 (Non-Discounted)			Million Metric Tons of CO_2 from 2023 to 2050 (Non-Discounted)			2016 $ per Metric Ton of CO_2
Reference Case	6.0	48.6	N/A	334.7	5,865	N/A	N/A
Renewables-Only Case	3.6	50.1	-0.9	200.7	5,832	-167	251
Market-Based Generation Case	3.6	49.7	-1.4	200.7	5,888	-136	54

Region	Coincident Peak Electric Generation Requirement in 2035 (Space & Water Heating)			Incremental Electric Consumption Levels in 2035 (Space & Water Heating)		
	Maximum Hourly Peak Generation (GW)	Average Winter Day (November - April) (GW)	Normal Day June 2035 (GW)	2035 Annual Electric Consumption (GWh)	January 2035 Electric Consumption (GWh)	June 2035 Electric Consumption (GWh)
Renewables-Only Case	13.5	2.6	0.9	11,293	2,523	340
Market-Based Generation Case	13.5	2.6	0.9	11,293	2,523	340

Sector Description	Units	Base Case	Change from Base Case	
			Renewables-Only	Market-Based Generation
Consumer Energy Purchases	2016 $ Billions	38.6	-5.6	-5.6
Consumer Capital Costs		193.0	7.2	7.2
Power Sector Capital Costs		20.0	0.7	0.8
Transmission Capital Costs		N/A	4	0
Total Costs		251.6	6.3	2.3
Pre-Electrification: Average Household Annual Household Energy Costs	2016 $ per Household	1,975	N/A	N/A
Cumulative Change in Costs Per Converted Household		N/A	1,970	740
Annualized Change in Costs Per Converted Household		N/A	130	50

B-9 West

Exhibit B-18 West Regional Generation and Capacity

Generation Type	2035 Generation (GWh)				2035 Capacity (MW)			
	2016	Reference Case	Renewables-Only	Market-Based Generation	2016	Reference Case	Renewables-Only	Market-Based Generation
Existing Units	**567,251**	**541,800**	**587,577**	**571,951**	**170,002**	**168,265**	**177,505**	**172,537**
Coal	66,504	51,140	52,062	49,870	12,324	7,036	7,206	6,902
Nuclear	58,042	40,475	40,475	40,475	7,335	5,115	5,115	5,115
Natural Gas	197,704	148,572	183,836	176,260	60,162	59,935	64,439	63,782
Wind & Solar	56,664	82,151	82,151	82,151	28,117	38,258	38,258	38,258
Other Renewables	183,105	214,687	224,609	218,490	52,661	57,042	58,356	57,532
Oil/Gas & Other	5,230	4,775	4,444	4,704	9,403	880	4,130	948
New Units	**0**	**82,632**	**79,597**	**97,154**	**0**	**23,479**	**25,800**	**25,746**
Natural Gas	0	9,156	5,496	22,535	0	1,261	1,261	3,071
Wind & Solar	0	73,476	73,868	74,619	0	22,218	22,196	22,675
Energy Storage	0	0	233	0	0	0	2,343	0
West Total	**567,251**	**624,432**	**667,174**	**669,105**	**170,002**	**191,744**	**203,305**	**198,283**

Exhibit B-19 West Regional Results

Region	Consumer Direct-Use Natural Gas Use	Power Sector Natural Gas Use	Change in Natural Gas Use	Cumulative Household CO_2 Emissions (Natural Gas, Propane, and Fuel Oil)	Cumulative Power Sector CO_2 Emissions	Cumulative Total Change in CO_2 Emissions	Cost of Emissions Reduction (Discounted to 2023)
Units	Tcf from 2023 to 2050 (Non-Discounted)			Million Metric Tons of CO_2 from 2023 to 2050 (Non-Discounted)			2016$ per Metric Ton of CO_2
Reference Case	20.2	31.4	N/A	1,183	3,692	N/A	N/A
Renewables-Only Case	11.7	37.9	-2.0	689	4,039	-147	749
Market-Based Generation Case	11.7	36.9	-3.0	689	4,032	-155	485

Region	Coincident Peak Electric Generation Requirement in 2035 (Space & Water Heating)			Incremental Electric Consumption Levels in 2035 (Space & Water Heating)		
	Maximum Hourly Peak Generation (GW)	Average Winter Day (November - April) (GW)	Normal Day June 2035 (GW)	2035 Annual Electric Consumption (GWh)	January 2035 Electric Consumption (GWh)	June 2035 Electric Consumption (GWh)
Renewables-Only Case	44.7	8.8	4.4	41,892	7,088	1,552
Market-Based Generation Case	44.7	8.8	4.4	41,892	7,088	1,552

Sector Description	Units	Base Case	Change from Base Case	
			Renewables-Only	Market-Based Generation
Consumer Energy Purchases	2016$ Billions	171.9	8.3	8.3
Consumer Capital Costs		742.5	34.5	34.5
Power Sector Capital Costs		115.6	10.7	7.4
Transmission Capital Costs		N/A	21.5	15.3
Total Costs		1030.0	75	65.5
Pre-Electrification: Average Household Annual Household Energy Costs	2016 $ per Household	1,653	N/A	N/A
Cumulative Change in Costs Per Converted Household		N/A	5,880	5,140
Annualized Change in Costs Per Converted Household		N/A	390	340

B-10 U.S. Lower 48

Exhibit B-20 U.S. Lower 48 Regional Generation and Capacity

Generation Type	2016	2035 Generation (GWh)				2016	2035 Capacity (MW)		
		Reference Case	Renewables-Only	Market-Based Generation			Reference Case	Renewables-Only	Market-Based Generation
Existing Units	**3,898,887**	**3,797,327**	**3,999,903**	**3,740,849**		**1,035,057**	**956,466**	**1,043,809**	**975,131**
Coal	1,142,790	983,392	917,032	925,989		268,153	156,212	191,098	155,915
Nuclear	776,778	716,492	714,743	710,311		99,100	90,601	90,601	90,601
Natural Gas	1,311,444	1,331,115	1,579,671	1,334,573		376,457	414,787	419,669	418,530
Wind & Solar	249,072	348,535	348,535	348,535		98,619	135,049	135,049	135,049
Other Renewables	330,482	378,891	396,420	383,278		108,233	115,007	118,763	115,777
Oil/Gas & Other	88,321	38,902	43,501	38,163		84,496	44,809	88,629	59,259
New Units	**0**	**469,374**	**756,150**	**748,626**		**0**	**138,707**	**358,676**	**241,070**
Natural Gas	0	170,110	173,489	417,076		0	36,917	36,917	128,422
Wind & Solar	0	299,263	547,043	331,550		0	101,791	168,102	112,648
Energy Storage	0	0	35,619	0		0	0	153,657	0
U.S. Lower 48 Total	**3,898,887**	**4,266,700**	**4,756,054**	**4,489,474**		**1,035,057**	**1,095,174**	**1,402,484**	**1,216,201**

Exhibit B-21 U.S. Lower 48 Regional Results

Region	Consumer Direct-Use Natural Gas Use	Power Sector Natural Gas Use	Change in Natural Gas Use	Cumulative Household CO_2 Emissions (Natural Gas, Propane, and Fuel Oil)	Cumulative Power Sector CO_2 Emissions	Cumulative Total Change in CO_2 Emissions	Cost of Emissions Reduction (Discounted to 2023)
Units	Tcf from 2023 to 2050 (Non-Discounted)			Million Metric Tons of CO_2 from 2023 to 2050 (Non-Discounted)			2016 per Metric Ton of CO_2
Reference Case	127.1	297.5	N/A	8,382.2	49,097	N/A	N/A
Renewables-Only Case	71.8	334.3	-18.6	4,769.4	50,694	-1,909	806
Market-Based Generation Case	95.2	346.7	18.1	6,276.3	50,007	-1,196	572

Region	Coincident Peak Electric Generation Requirement in 2035 (Space & Water Heating)			Incremental Electric Consumption Levels in 2035 (Space & Water Heating)		
	Maximum Hourly Peak Generation (GW)	Average Winter Day (November - April) (GW)	Normal Day June 2035 (GW)	2035 Annual Electric Consumption (GWh)	January 2035 Electric Consumption (GWh)	June 2035 Electric Consumption (GWh)
Renewables-Only Case	486.7	109.1	22.9	456,118	95,887	7,617
Market-Based Generation Case	266.7	52.2	14.2	223,825	45,231	5,840

Sector Description	Units	Base Case	Change from Base Case	
			Renewables-Only	Market-Based Generation
Consumer Energy Purchases	2016 $ Billions	1,018	615.1	313.5
Consumer Capital Costs		3,342	144.6	101.8
Power Sector Capital Costs		223	318.9	121.6
Transmission Capital Costs		N/A	107.1	53.2
Total Costs		4,583	1,185.6	590.1
Pre-Electrification: Average Household Annual Household Energy Costs	2016 $ per Household	1,990	N/A	N/A
Cumulative Change in Costs Per Converted Household		N/A	21,140	15,830
Annualized Change in Costs Per Converted Household		N/A	1,420	1,060

Exhibit B-22 North America Regional Generation and Capacity

Generation Type	2016	2035 Generation (GWh)				2016	2035 Capacity (MW)		
		Reference Case	Renewables-Only	Market-Based Generation			Reference Case	Renewables-Only	Market-Based Generation
Existing Units	**4,511,467**	**4,404,042**	**4,619,157**	**4,344,442**		**1,175,935**	**1,097,072**	**1,189,379**	**1,118,713**
Coal	1,203,359	1,040,841	974,315	983,416		277,673	164,867	199,753	164,570
Nuclear	873,198	789,568	785,444	782,166		112,465	100,912	100,912	100,912
Natural Gas	1,350,699	1,376,059	1,628,495	1,377,768		394,133	434,852	439,734	438,595
Wind & Solar	271,561	373,089	373,089	373,089		110,593	147,742	147,742	147,742
Other Renewables	717,710	776,980	805,379	781,236		190,656	201,025	206,768	201,795
Oil/Gas & Other	94,941	47,505	52,434	46,766		90,416	47,673	94,470	65,099
New Units	**0**	**543,889**	**840,328**	**835,447**		**0**	**159,452**	**387,108**	**269,912**
Natural Gas	0	173,739	183,851	421,443		0	42,756	49,789	139,810
Wind & Solar	0	370,149	620,859	414,004		0	116,696	183,663	130,102
Energy Storage	0	0	35,619	0		0	0	153,657	0
North America Total	**4,511,467**	**4,947,930**	**5,459,486**	**5,179,887**		**1,175,935**	**1,256,525**	**1,576,487**	**1,388,625**

Appendix C: ICF IPM® Model Description

IPM® is a detailed engineering/economic capacity expansion and production-costing model of the power and industrial sectors supported by an extensive database of every boiler and generator in the nation. It is a multi-region model that provides capacity and transmission expansion plans, unit dispatch and compliance decisions, and power and allowance price forecasts, all based on power market fundamentals.

IPM® explicitly considers gas, oil, and coal markets, power plant costs and performance characteristics, environmental constraints, and other power market fundamentals. Figure C-1 illustrates the key components of IPM®.

Figure C-1: IPM® Schematic

IPM® uses a dynamic linear programming model the electric demand, generation, and transmission within each region as well as the transmission grid that connects the regions.

All existing utility-owned boilers and generators are modeled, as well as independent power producers and cogeneration facilities that sell firm capacity into the wholesale market. IPM® also is capable of explicitly modeling individual (or aggregated) end-use energy efficiency investments. Each technology (e.g., compact fluorescent lighting) or general program (e.g., load control) is characterized in terms of its load shape impacts and costs. Costs can be characterized simply as total costs or more accurately according to its components (e.g., equipment or measure costs, program or equipment costs, and administrative costs), and penetration curves reflecting the market potential for a technology or program. End-use energy efficiency investments compete on a level playing field with traditional electric supply options to meet future demands. As supply side resources become more constrained or expensive (e.g., due to environmental regulation) more energy efficiency resources are used.

IPM® has been used in support of numerous project assignments including:

- Valuation studies for generation and transmission assets
- Forecasting of regional forward energy and capacity prices
- Air emissions compliance strategies and pollution allowances
- Impact assessments of alternate environmental regulatory standards
- Impact assessments of changes in fuel pricing
- Economic or electricity demand growth analysis
- Assessment of power plant retirement decisions
- Combined heat and power (CHP) analysis
- Pricing impact of demand responsiveness
- Determination of probability and cost of lost or unserved load

Outputs of IPM® include estimates of regional energy and capacity prices, optimal build patterns based on timing of need and available technology, unit dispatch, air emission changes, retrofit decisions, incremental electric power system costs (capital, FOM VOM), allowance prices for controlled pollutants, changes in fuel use, and fuel price impacts. Results can be directly reported at the national and power market region levels. ICF can readily develop individual state or regional impacts aggregating unit plant information to those levels. IPM® analyzes wholesale power markets and assesses competitive market prices of electrical energy, based on an analysis of supply and demand fundamentals. IPM® projects zonal wholesale market power prices, power plant dispatch, fuel consumption and prices, interregional transmission flows, environmental emissions and associated costs, capacity expansion and retirements, and retrofits based on an analysis of the engineering economic fundamentals. The model does not extrapolate from historical conditions but rather for a given set of future conditions which determine how the industry will function (i.e., new demand, new power plant costs, new fuel market conditions, new environmental regulations, etc.), provides a least cost optimization projection. The optimization routine has dynamic effects (i.e., it looks ahead at future years and simultaneously evaluates decisions over a specified time horizon). All major factors affecting wholesale electricity prices are explicitly modeled, including detailed modeling of existing and planned units, with careful consideration of fuel prices, environmental allowance and compliance costs, transmission constraints and operating constraints. Based on looking at the supply/demand balance in the context of the various factors discussed above, IPM® projects hourly spot prices of electric energy within a larger wholesale power market. IPM® also projects an annual "pure" capacity price.

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100 YEARS

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An American Gas Association Study

prepared by ICF