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November 19, 2021

Council on Environmental Quality
730 Jackson Pl NW
Washington, DC 20506

RE: Comments of AGA and APGA on the Department of Energy's 2021 Climate Adaptation and Resilience Plan, Docket ID: CEQ–2021–0003

Council on Environmental Quality:

The American Gas Association ("AGA") and the American Public Gas Association ("APGA") (collectively, "Commenters") appreciate the opportunity to comment on the Department of Energy's ("DOE") 2021 Climate Adaptation and Resilience Plan ("DOE Plan"), CEQ–2021–0003.[1] On October 7, 2021 the Biden-Harris Administration released plans developed by more than 20 federal agencies, including DOE, that outline the steps each agency will take to ensure their facilities and operations adapt to and are increasingly resilient to climate change impacts. The Council on Environmental Quality ("CEQ") and Office of Management and Budget ("OMB") requested public input on the agency climate adaptation plans. As discussed in these comments, Commenters believe that the use of the natural gas system can provide energy resilience to DOE's facilities.[2]

I. Introduction

The American Gas Association, founded in 1918, represents more than 200 local energy companies that deliver clean natural gas throughout the United States. There are more than 76 million residential, commercial, and industrial natural gas customers in the U.S., of which 95 percent — more than 72 million customers — receive their natural gas from AGA members. AGA is an advocate 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 thirty percent of the United States' energy needs. The scale of importance of natural gas and its delivery systems and their role in providing safe, affordable, reliable, and resilient energy service choices to customers

[1] *See* Biden Administration Releases Agency Climate Adaptation and Resilience Plans from Across Federal Government (Oct. 7, 2021) available at https://www.whitehouse.gov/briefing-room/statements-releases/2021/10/07/fact-sheet-biden-administration-releases-agency-climate-adaptation-and-resilience-plans-from-across-federal-government/. *See also*, https://www.regulations.gov/docket/CEQ-2021-0003 and https://www.regulations.gov/docket/CEQ-2021-0003/document.

[2] AGA anticipates submitting comments, either jointly or individually, on other Climate Adaptation and Resilience Plans issue by various federal agencies. This submission only addresses the DOE Plan.

must not be understated. AGA 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.

The American Public Gas Association is the trade association for approximately 1,000 communities across the U.S. that own and operate their retail natural gas distribution entities. They include municipal gas distribution systems, public utility districts, county districts, and other public agencies, all locally accountable to the citizens they serve. Public gas systems operate as not-for-profit utilities and provide safe, reliable, and affordable energy to their customers. APGA members support their communities by delivering fuel to be used for cooking, clothes drying, and space and water heating, as well as for various commercial and industrial applications.

On January 27, 2021, President Biden issued Executive Order 14008, Tackling the Climate Crisis at Home and Abroad. Section 211 of Executive Order 14008 directs executive agencies to draft action plans that describe the steps each executive agency can take to bolster adaptation and increase resilience to the impacts of climate change. According to Executive Order 14008, the action plans should describe the agency's climate vulnerabilities and describe the agency's plan to use procurement to increase the energy and water efficiency of Government installations, buildings and facilities and ensure they are climate ready. The DOE Plan discusses, among other things, electrification,[3] transitioning away from natural gas,[4] and building code changes.[5] AGA and APGA are providing comments on DOE's Plan to ensure consideration of critical energy system issues. Specifically, Commenters urge DOE to fully consider: the impacts of DOE's full electrification on entire energy system; the resilience and reliability provided by natural gas systems; the implementation of codes that include source emissions; the role of combined heat and power ("CHP"); and, the natural gas system's role in developing and delivering emerging renewable energy sources.

II. DOE Should Fully Consider the Potential Impacts that an Electrification Only Pathway Would Have on the Agency, the Entire Energy System, and Customers

The DOE Plan provides that DOE will identify approaches to enhance electrification and that electrification is one pillar of an adaptation and decarbonization strategy.[6] As DOE contemplates issues related to electrification, it should consider a panoply of issues; specifically, DOE should examine the impacts electrification would have on its own operations and on the entire energy system.[7]

Policy-driven electrification of natural gas end-uses will impact existing and future natural gas utility customers. For example, in 2018, AGA engaged a cross-functional team of experts to evaluate policy-driven electrification of the U.S. residential sector. The study, "Implications of

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[3] *See* DOE Plan at p. 8.
[4] *Id.* at p. 10.
[5] *Id.* at pp. 12 and 14.
[6] *Id.* at p. 8.
[7] A large segment of the country's industrial base relies on natural gas. *See* "Natural gas expected to remain most-consumed fuel in the U.S. industrial sector," Energy Information Administration (May 1, 2018), available at https://www.eia.gov/todayinenergy/detail.php?id=35152 (last visited, November 17, 2021).

Policy-Driven Residential Electrification,"[8] appended as Attachment A, identified numerous challenges to electrification including:

- 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 found that a policy targeting widespread electrification of the U.S. residential sector would result in only a small fraction of greenhouse gas emissions reductions; could be financially burdensome to customers; 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.

In addition to the study, AGA in consultation with outside consultants, is in the process of developing city-specific evaluations of the implications of a policy of forced electrification. Currently, a report has been completed for Columbus, OH, "Electrifying the Columbus, Ohio Metro Area's Building Stock – Economic and Power Market Impacts."[9] The report is appended as Attachment B.

Furthermore, the impacts of policy-driven electrification on the reliability and resilience of the energy system must be fully examined. The natural gas pipeline, distribution and storage systems can deliver large capacity to meet variable demand. The U.S. natural gas system delivers three times more energy on the coldest day of the year than the electricity grid provides on the hottest day of the year.[10] In some regions "on a peak demand day, the natural gas network delivers up to four times as much energy as the electric network on a peak day."[11] To that end, DOE should determine if the electric transmission planning processes adequately anticipate DOE's facility peak requirements.

[8] Implications of Policy-Driven Residential Electrification (July 2018) available at https://www.aga.org/research/reports/implications-of-policy-driven-residential-electrification/ (last visited, November 17, 2021).
[9] Electrifying the Columbus, Ohio Metro Area's Building Stock – Economic and Power Market Impacts (August 2020) available at https://www.aga.org/research/reports/implications-of-policy-driven-residential-electrification/grounded-in-reality-the-implications-of-electrification/ (last visited November 17, 2021).
[10] Based on Energy Information Administration and market data.
[11] *See* "Investing in the US Natural Gas Pipeline System to Support Net-Zero Targets," *supra* n.7, at p. 25.

Finally, DOE must recognize the critical function of the deployment and use of natural gas standby generators that operate extensively during electric outages. Specifically, during electric outages, natural gas generators provide power for critical operations such as hospitals, retirement homes, fire and police stations, food suppliers, homes, businesses, etc.. In considering the support for "electrification," DOE must also consider that a complete elimination of natural gas availability would be counter-productive to the nation's goal of maintaining a sustainable and reliable energy system.

III. The Gas System is Reliable and Resilient, and it Supports the Entire Energy System

One of the focuses of the DOE Plan is resilience and the development of resilience plans that identify site level resilience solutions.[12] As part of DOE's process it should not ignore the resilience of the natural gas pipeline, distribution, and storage system. The resilience characteristics of the U.S. gas system allow it to contribute to the overall resilience of the U.S. energy system, and such attributes should be recognized. The resilience of the natural gas system give it the ability to withstand, adopt to, and recover from disruptions. The characteristics that permit such resilience include, for example: 1) the inherent resilience of natural gas, *e.g.*, it can be stored or compressed; 2) the physical resilience of natural gas infrastructure due to the fact that transportation, distribution, and storage facilities are generally underground; and 3) the operational standards of the system permit flexibility, *i.e.*, multiple transportation and storage options. As DOE considers issues related to resilience, it should not lose sight of the fact that the gas system is currently providing substantial reliability and resilience benefits to the entire U.S. energy system. The strength of the current system resilience is a byproduct of a regulatory environment that has valued investment in a reliable, ratable, and safe set of assets designed around a legacy demand forecast and historical heating degree day planning. A resilient energy system is essential to the operation of nearly every critical function and sector of the U.S. economy as well as the communities that depend upon the energy system's services. Disruptions to the U.S. energy system create widespread economic and social impacts, including losses in productivity, health, and safety issues, and—in the most extreme cases—loss of life. As DOE deliberates the design and structure of the future of its energy infrastructure, resilience must be considered.

The American Gas Foundation issued a report in January 2021 "Building a Resilient Energy Future: How the Gas System Contributes to U.S. Energy System Resilience" ("AGF Resilience Report"),[13] appended as Attachment C, which provides a framework for regulators, policymakers, and other stakeholders to examine energy system resilience and the role of the natural gas system. The AGF Resilience Report highlights the gas system's ability to support resilience through its inherent, physical, and operational capabilities that enable it to meet the volatile demand profiles resulting from resilience events.[14] The AGF Resilience Report found that the gas system supports a quick response to events and provides long-duration storage resources to meet peak and seasonal energy demand.[15] Large, catastrophic failures of the energy system have been few and far between, but they do occur, and the gas system has performed well,

[12] *See* DOE Plan at p. 5.
[13] American Gas Foundation, "Building a Resilient Energy Future: How the Gas System Contributes to U.S. Energy System Resilience" (January 2021) available at https://gasfoundation.org/2021/01/13/building-a-resilient-energy-future/ (last visited, November 17, 2021) ("AGF Resilience Report").
[14] AGF Resilience Report at 13-24.
[15] *Id*. at 3-4 and 36.

overcoming periods of high stress that have threatened its resilience.[16] These high stress events are becoming more frequent due to the increase in the frequency and severity of extreme weather events associated with climate change.[17]

For DOE to successfully build for the future and invest in the right set of resilience solutions, it is important to understand how the energy system has performed under recent resilience events. To that end, the AGF Resilience Report analyzed the U.S. energy system's potential vulnerabilities and resilience attributes.[18] In short, the multitude and diversity of resilience assets that already exist as part of the energy system have made the difference—facilitating energy flows to critical services and customers.[19] As discussed herein, DOE should fully consider resilience and reliability as it considers potential electrification and changing its energy mix.

IV. DOE Must Support a Comprehensive Set of Model Building Energy Codes

The DOE Plan states under Priority Action Three, that:

> DOE's Office of Project Management Oversight and Assessment (PM) will develop a requirement that all new construction and major renovation projects meet or exceed the latest building standards and codes as set by ASHRAE 90.1, where appropriate. DOE will also review the new Federal building codes expected in summer of 2021, as well as other building energy standards and codes, such as the International Energy Conservation Code and International Building Code, to further promote climate action and determine the feasibility of making those codes mandatory for all new building construction at DOE. As an example, DOE is currently using the 2013 version of ASHRAE Standard 90.1, as required by Federal energy efficiency performance standards (10 CFR §433) and will consider accelerating the adoption of ASHRAE Standard 90.1 for new DOE buildings. By September 2021, PM will examine the feasibility of mandating the most recent ASHRAE standard for new construction, and if appropriate, will work through DOE's Directives Review Board (DRB) to institute any necessary changes by December 2021.[20]

In adopting the latest ASHRAE 90.1 standards and International Energy Conservation Code ("IECC"), DOE must evaluate energy efficiency improvements and energy consumption reductions based on measuring "source" energy and not "site" energy to ensure that the true energy reductions are achieved. DOE has previously recognized that a source energy metric usage is the

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[16] *Id.* at 3.
[17] *Id.* at 11.
[18] *Id.* at 24-45. The report exams Polar Vortex (January 2019), Polar Vortex (February 2014), Hurricane Isaias (August 2020) and Heat, Drought, and Wildfires (August 2020).
[19] *Id.*
[20] DOE Plan at p. 12.

technically correct measurement for energy consumption. Moreover, source energy metrics are used in federal energy programs including Environmental Protection Agency's ("EPA") Energy Star for Commercial Buildings and DOE's own Home Energy Score. Using "source energy" provides the only means of assessing energy performance on full fuel cycle energy consumption and ultimately carbon footprints since site energy metrics alone cannot account for these upstream energy system losses. Thus, it is incumbent on DOE to require any energy consumption estimates that are determined by implementing the provisions in the model building energy codes such as ASHRAE 90.1 or the IECC, that the energy usage must be based on "source" energy.

DOE must also recognize that a straight-out endorsement and implementation of full "electrification" programs is not a guarantee that there will be a reduction in homes and buildings energy usage and a decrease in overall emissions. In fact, a recent analysis by the National Institute of Standards and Technology ("NIST"),[21] shows that under current full fuel cycle emissions and energy costs, when comparing two identical and comparable homes using either natural gas or electric service for space conditioning and service water heating there are present economic and environmental advantages for homes using natural gas. NIST used its Net Zero Energy Residential Test Facility in Gaithersburg, Maryland to gather measurements for its computational analysis using its Building Industry Reporting and Design for Sustainability (BIRDS v4.0) modeling platform. The NIST researchers conceded that with changes in energy prices and grid electric emissions factors in the future, the comparative analysis may change. However, the researchers pointed out that, to date, "little research has been conducted looking at the impact of which fuel source is used, gas or electric, on achieving low-energy and low-impact goals" and that the analysis approach allows making "a true apples-to-apples comparison of gas versus electric for their respective energy, environmental and economic impacts." The analysis timeframe covers 30 years, which is consistent with other forecasting timeframes such as those of the Energy Information Administration's Annual Energy Outlook ("AEO"), which forecasts energy and generation mixes to 2050 and predicts very stable source efficiencies for natural gas and electricity. Over that period, both the NIST researchers and the AEO predict reduced carbon intensity in electricity generation, but a review of the NIST findings does not show that environmental competitiveness of the two end use energy forms would change. It is important to note that NIST is under the U.S. Department of Commerce and is considered one of the most credible research organizations whose independent work is well respected all over the world. DOE needs to be cognizant of the energy cost advantages and environmental benefits of the direct use of natural gas in homes, businesses, and industrial applications.

V. DOE Should Include Combined Heat and Power in its Plan

Combined heat and power ("CHP") is a well-established technology being used by various industries for decades. For example, in the U.S., there are over 4,700 CHP systems totaling 81,683 MW of power across various industries.[22] However, a 2016 DOE technical report noted that the

[21] *See* NIST, Gas vs Electric: Heating System Fuel Source Implications on Low-Energy Single-Family Dwelling Sustainability Performance, September 2019, available at https://www.nist.gov/news-events/news/2019/05/gas-vs-electric-nist-says-fuel-choice-affects-efforts-achieve-low-energy and https://tsapps.nist.gov/publication/get_pdf.cfm?pub_id=926046 (last visited November 17, 2021). Information on NIST is available at https://www.nist.gov/.

[22] DOE, Combined Heat and Power Installation Database, available at https://doe.icfwebservices.com/chp (last visited November 17, 2021).

potential is far greater.[23] CHP systems can be powered by a variety of clean fuels such as agricultural biomass, digester gas, landfill gas, liquid biofuel, solid biomass, and wood.[24] The DOE Plan does not reference any of these opportunities and the benefits CHP can provide. Pairing CHP with low carbon fuels, such as renewable natural gas and hydrogen, is an efficient use of those fuels that can significantly lower greenhouse gas emissions.

DOE and EPA have recognized the resilience of CHP. For example, DOE's Better Buildings Initiative implemented a CHP for Resiliency Accelerator,[25] which worked to support and expand the consideration of CHP solutions to keep critical infrastructure operational every day and night regardless of external events. Furthermore, DOE's Office of Energy Efficiency and Renewable Energy explained that "[CHP] is an efficient way to produce both electricity and thermal energy from a single source, with the ability to keep operating separate from the grid. By operating independently from the grid, CHP can continue to provide services to a user during grid outages."[26] Moreover, EPA has recognized the resilient value of CHP. EPA's CHP Partnership determined that CHP is a superior energy resource for hospitals because it can provide all of a hospital's energy services efficiently and indefinitely during grid outages.[27] Additionally, in addition to providing reliable energy and making hospitals more resilient, CHP can help hospitals reduce costs and meet their sustainability and emissions reduction goals.[28] These governmental efforts build on the findings of other organizations that view CHP as adding resilience to the energy system and reducing emissions.[29] As discussed herein, DOE and other entities have already recognized the value of CHP; therefore, DOE should incorporate CHP into its plan in recognition of the growing need to deliver renewable and decarbonized sources of heat, especially in the industrial and commercial sectors.

VI. The Gas System is Needed for the Delivery and Storage of Renewable Gases and Hydrogen

The DOE Plan states that DOE is considering using electricity to replace site-delivered fossil fuels.[30] Moreover, the DOE Plan states that DOE plans to increase resilience across its sites

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[23] DOE, Combined Heat and Power (CHP) Technical Potential in the United State, March 2016, available at https://www.energy.gov/sites/default/files/2016/04/f30/CHP%20Technical%20Potential%20Study%203-31-2016%20Final.pdf (last visited November 17, 2021).

[24] *See, e.g.*, *id.*; EPA, Biomass Combined Heat and Power Catalog of Technologies, September 2007, available at https://www.epa.gov/sites/default/files/2015-07/documents/biomass_combined_heat_and_power_catalog_of_technologies_v.1.1.pdf (last visited November 17, 2021).

[25] *See* https://betterbuildingssolutioncenter.energy.gov/accelerators/combined-heat-and-power-resiliency (last visited November 17, 2021).

[26] *See* https://betterbuildingssolutioncenter.energy.gov/sites/default/files/attachments/CHP_Resiliency_in_Critical_Infrastructure_0.pdf (last visited November 17, 2021).

[27] *See* https://www.epa.gov/chp/chp-hospitals-superior-energy-superior-patient-care (last visited November 17, 2021).

[28] *Id.*

[29] *See* Combined Heat and Power Alliance, CHP and a Changing Climate: Reducing Emissions and Improving Resilience, Jan. 19. 2021, available at https://chpalliance.org/chp-and-a-changing-climate-reducing-emissions-and-improving-resilience/ (last visited November 17, 2021).

[30] *See* DOE Plan at p. 8.

by deploying cost-effective climate resilient and carbon pollution-free energy technologies.[31] In addition, DOE will assess practices to enhance the purchase of low carbon footprint products and services. DOE should consider that the gas system is resilient and can be used to deliver and store lower emissions fuels, such as renewable gases and hydrogen. Natural gas and the extensive infrastructure network that supports it has been a cornerstone of America's energy economy for more than a century. Today, hundreds of millions of Americans rely on this infrastructure and the energy it delivers to heat their homes, power their businesses, and manufacture goods. This is the same system used to supply natural gas to DOE's facilities. 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 through pipeline replacement and modernization efforts. These commitments continue, and natural gas utility pipeline networks and operational practices are constantly evolving, ever improving, and becoming increasingly more flexible. As our nation moves towards a lower-carbon economy and embraces new fuels and technologies, the gas network is ready to meet these changes and will remain foundational to our future. As natural gas utilities plan for the future, the reimagination of pipeline infrastructure for deliveries of energy sources beyond geologic natural gas is just one of the many steps AGA and APGA members are taking to promote sustainability, reduce emissions, and maintain commitments to deliver safe, cost-effective, and reliable energy.

As part of this effort, gas utilities recognize the integral role that renewable gases, such as renewable natural gas ("RNG")[32] and hydrogen, can play in reducing greenhouse gas emissions from their operations and their customers. EPA recognizes that the "[u]se of RNG can provide benefits in terms of fuel security, economic revenues or savings, local air quality and greenhouse gas emission reductions."[33] RNG removes methane that would otherwise be released into the atmosphere, and reducing these emissions by capturing that methane can achieve significant positive, near-term impacts in mitigating global climate change.[34] Commenters strongly support expanding access to renewable gases in an effort to accelerate widespread accessibility and adoption of renewable and low-carbon energy sources. The gas system has the ability to store and deliver renewable energy derived from various sources and be a critical tool in reaching greenhouse gas reduction goals.

Many AGA members have already begun demonstrating their commitment to integrating renewable gases into their existing pipeline networks, and several APGA members are exploring options on how to bring these fuels to the communities they serve. To date, at least fifteen AGA member companies in the United States have established or are in the process of developing voluntary 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 natural gas throughput emissions and to offer customers a low-carbon and renewable energy option. Commenters closely track all state legislative and regulatory actions related to the use of RNG in the building sector,

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[31] *See* DOE Plan at p. 10.
[32] RNG is any pipeline compatible gaseous fuel derived from biogenic or other renewable sources that has lower lifecycle CO2e emissions than geological natural gas. The majority of the RNG produced today comes from capturing emissions from existing waste streams found in landfills, wastewater treatment plants, and animal manure. This gas must be treated and cleaned, raising it to a standard where it can be injected into existing natural gas pipelines. *See* https://www.aga.org/natural-gas/renewable/ (last visited November 17, 2021).
[33] https://www.epa.gov/lmop/renewable-natural-gas (last visited November 17, 2021).
[34] *Id*.

and activity has increased significantly over the last several years. Furthermore, utility investment in hydrogen is increasing, from piloting hydrogen production technologies to evaluating the impacts on direct-use natural gas equipment. Beyond technical engagement, many natural gas utilities 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 natural gas utilities' continued commitment to reducing emissions.

Commenters request that DOE examine the usefulness and benefits that the gas system can provide in meeting customers' demand for renewable gases. Furthermore, DOE should not assume electrification is the only pathway for decarbonization as such an assumption would hinder expanded utilization of RNG and hydrogen to serve DOE facilities. Moreover, continued use of the existing gas system with the inclusion of RNG and hydrogen could mitigate the requirement to site, permit and build electric infrastructure. RNG use can also increase the resilience of the energy system by providing a locally sourced supply of clean energy. As DOE is aware, permitting, approving, and building energy infrastructure projects is complex. DOE should seek to utilize existing gas infrastructure and not assume that the siting and permitting of any expanded electric transmission grid needed to replace the energy provided by the gas system to DOE facilities would be any easier than the current approval process for natural gas facilities. An efficient alternative is to maximize existing natural gas pipeline infrastructure and permit over time the expansion of RNG and hydrogen as a way to achieve carbon emissions reduction goals.

As part of any DOE analysis and future scenarios with greater shares of electric end-uses, DOE should also contemplate future scenarios where the gas system incorporates lower carbon fuels, such as RNG, hydrogen, and methanated hydrogen to provide service to government facilities. 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 RNG and hydrogen is a critical component of our nation's ability to reach ambitious greenhouse gas reduction goals.

VII. Additional Recommendations

As part of the overall effort to comply with Executive Order 14008, DOE should consider further efforts in the following areas as part of its plan:

- Technical and financial support in the development and deployment of high-efficient low emission emitting natural gas technologies for residential and commercial space heating and domestic water heating appliances and equipment using advanced materials, controls and technologies.
- Technical assistance in evaluating the impact of various blends of hydrogen and natural gas introduced into existing natural gas transmission and distribution systems to include longevity, reliability, leak potential, and elevated pressure, *etc.*
- Technical and financial support to expand the development of the types of natural gas appliances and equipment that can operate without electrical power and thus off the electric grid. This is an important, desirable operating feature that can maintain the gas

equipment's operation during power outages but reduces the operating cost by eliminating any electricity cost for the operation of the natural gas appliances and equipment.

VIII. Conclusion

The American Gas Association and American Public Gas Association respectfully request that CEQ, OMB, and DOE consider these comments on the DOE Plan. Commenters look forward to working with DOE as a willing partner in DOE's efforts to build a more resilient energy system that includes the direct use of natural gas.

Respectfully submitted,

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Dated: November 19, 2021

Enclosures: Attachment A - Implications of Policy-Driven Residential Electrification
Attachment B - Electrifying the Columbus, Ohio Metro Area's Building Stock – Economic and Power Market Impacts
Attachment C - Building a Resilient Energy Future: How the Gas System Contributes to US Energy System Resilience

ATTACHMENTS

ATTACHMENT A

Implications of Policy-Driven Residential Electrification

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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AGA

100 YEARS

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.

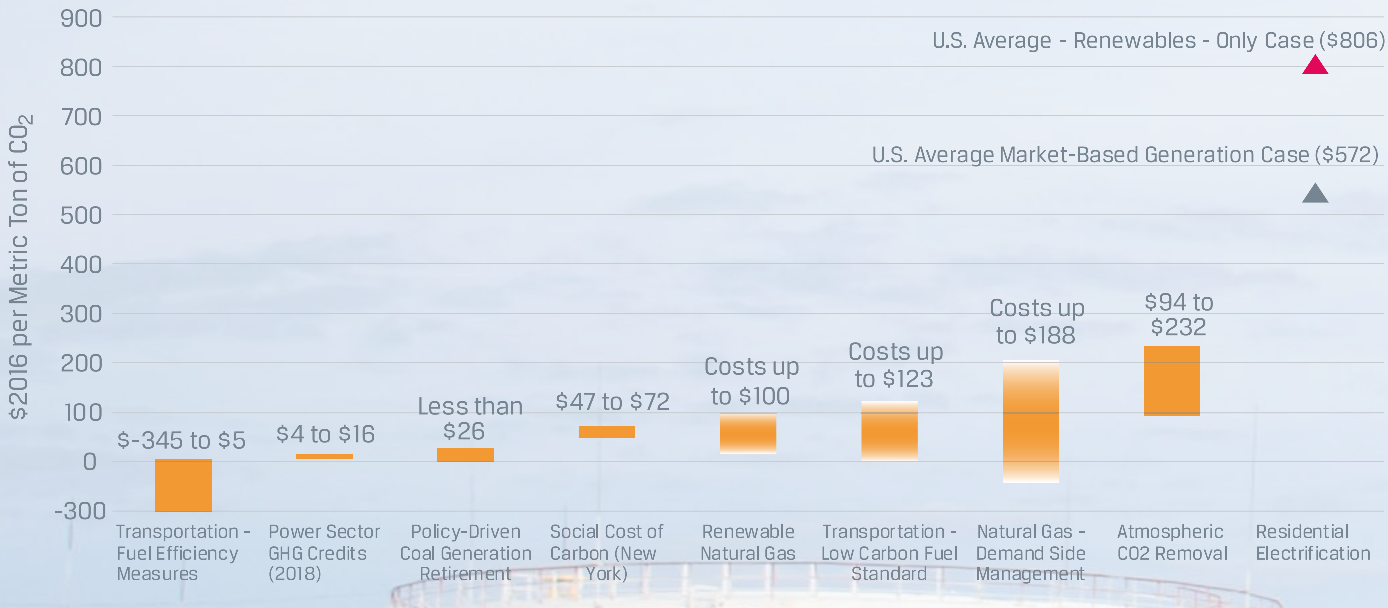
The increase in overall peak electricity demand resulting from the policy-driven residential electrification case would require an increase in total generation capacity in 2035 of between 10 and 28 percent relative to the Reference Case, depending on the power generation case.

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.

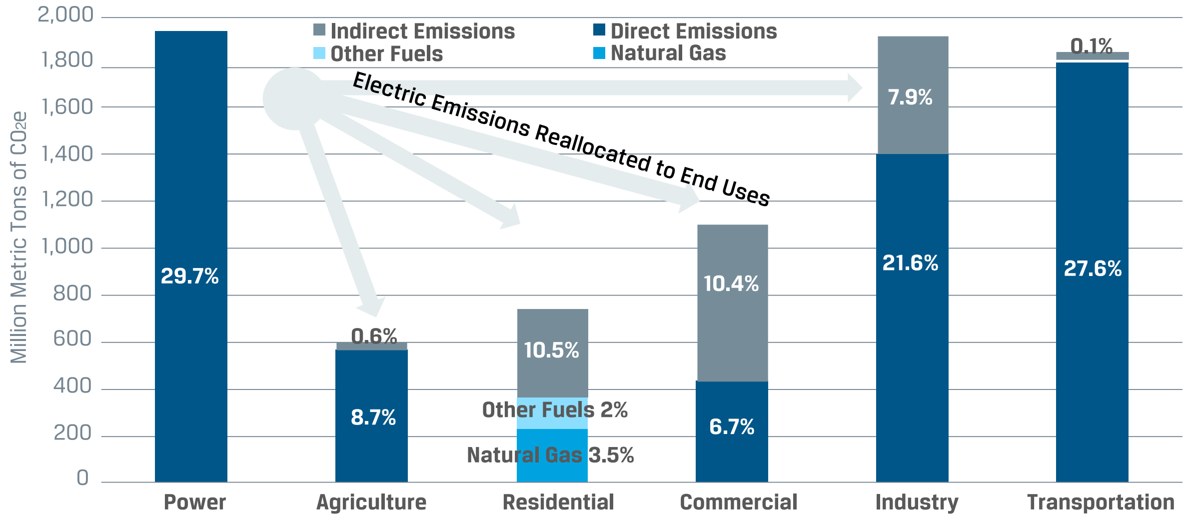
Policy-driven residential electrification also is viewed by some stakeholders as a means of reversing the impact of declining power usage trends on electric utilities and electric utility rates by increasing the number of appliances that run on electricity in residential households.

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.

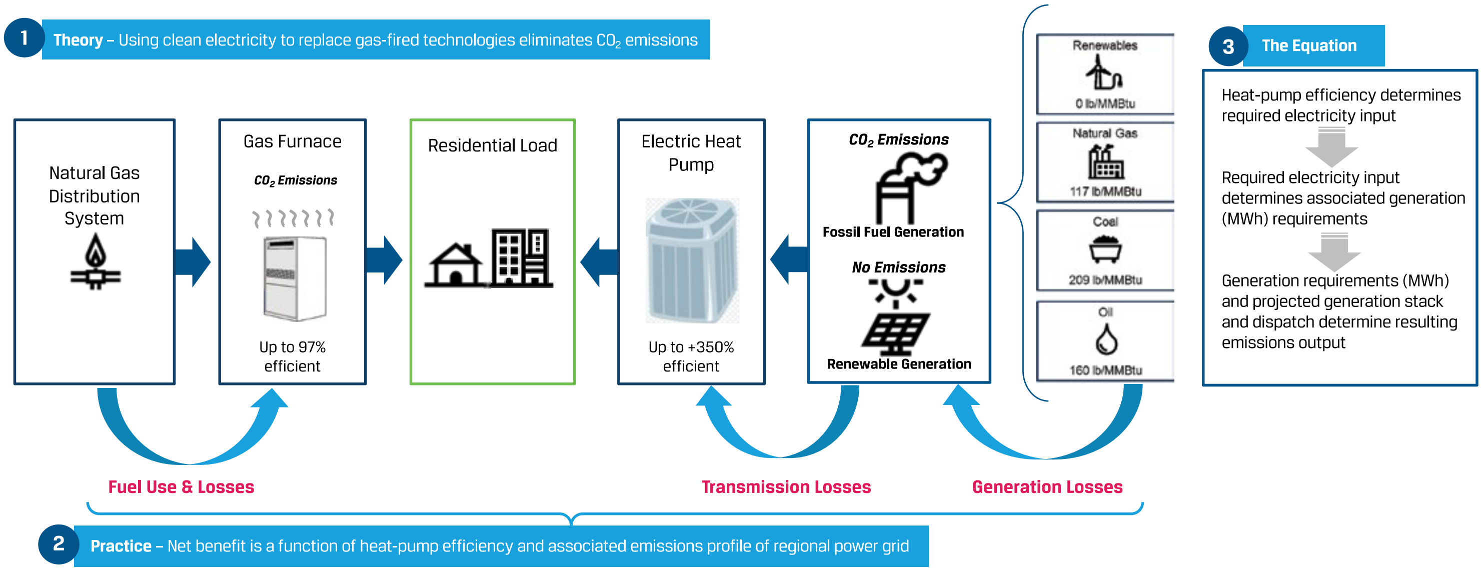
How Would Policy-Driven Residential Electrification Work?

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:

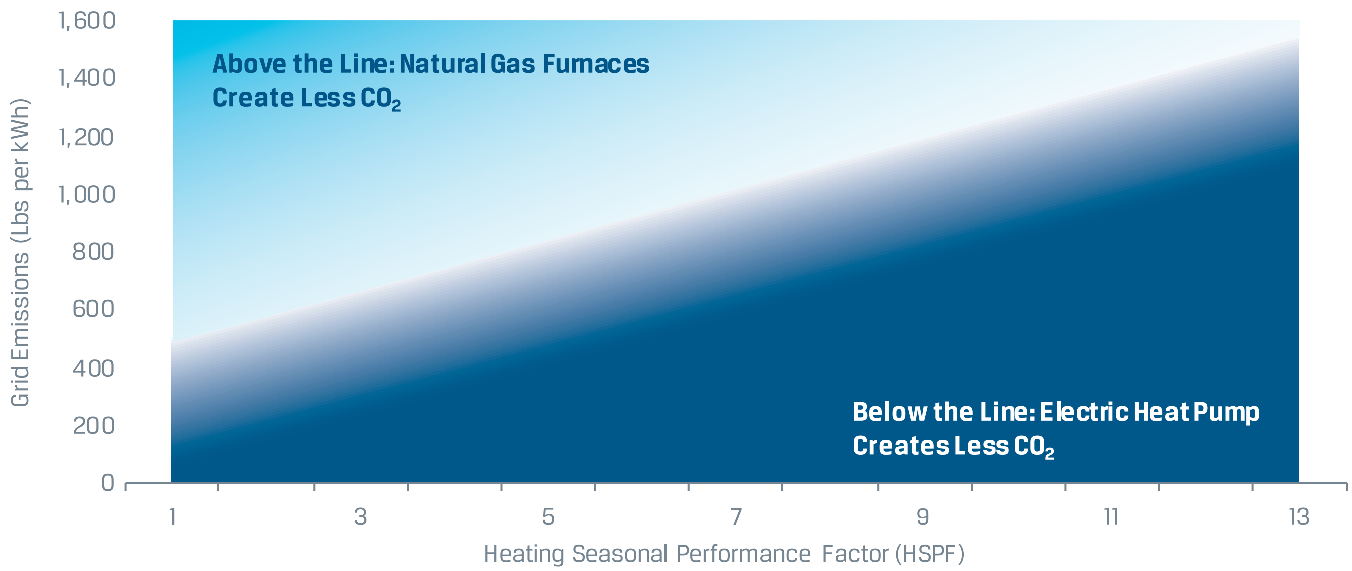
- The heating or water heating load being replaced.
- The efficiency of the appliance facing mandated replacement (e.g., the natural gas furnace and water heaters).
- The seasonal and climate-adjusted efficiency of the replacement electric technology (e.g., heat pump or heat pump water heater).
- The 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

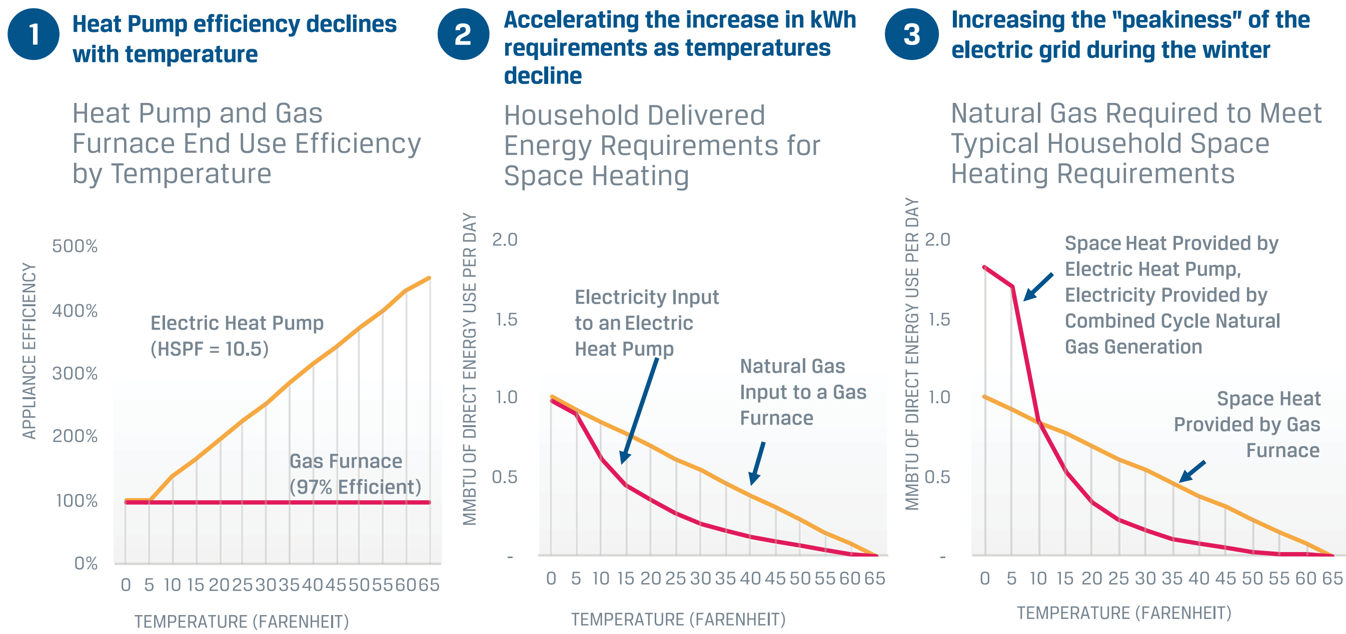
Heat pumps transfer heat rather than transforming chemical energy to heat through combustion. While combustion-based systems can never provide more energy than they consume, i.e., be more than 100 percent efficient, heat pumps can transfer more energy than they consume, i.e., be more than 100 percent 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.

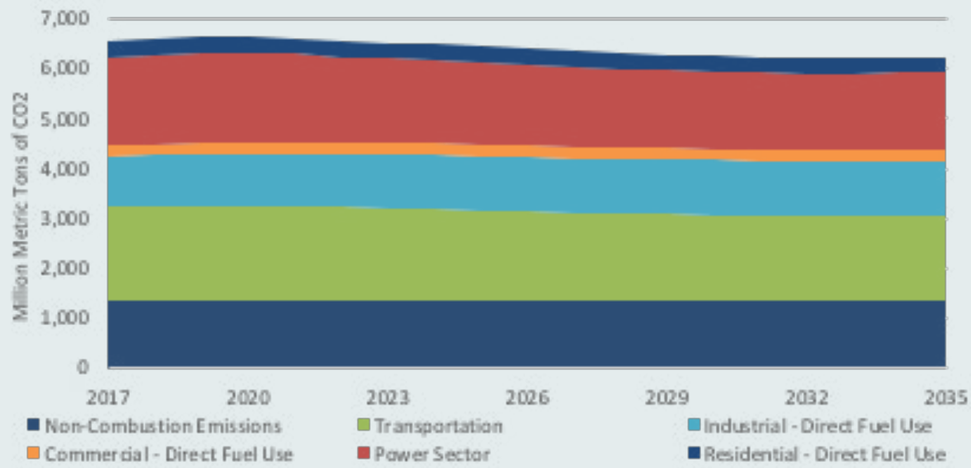
The detailed power sector results of the analysis are presented in Section 3.

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.

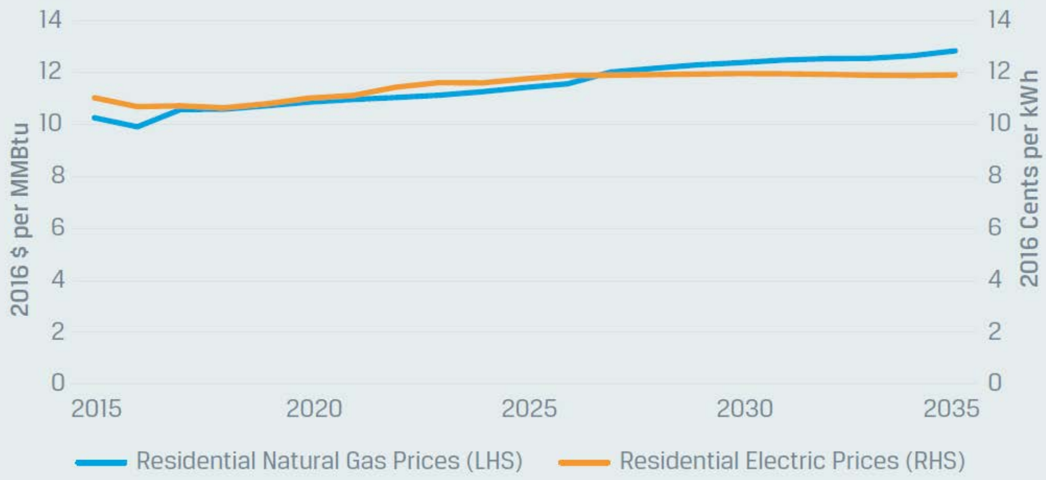
The AEO projects CO_2 emissions from combustion sources to decline from 5,182 million metric tons in 2017 to 4,827 million metric tons in 2035 and 5,084 million metric tons in 2050. Emissions from the power sector decline by 14 percent between 2017 and 2035, primarily due to a 78 percent increase in 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

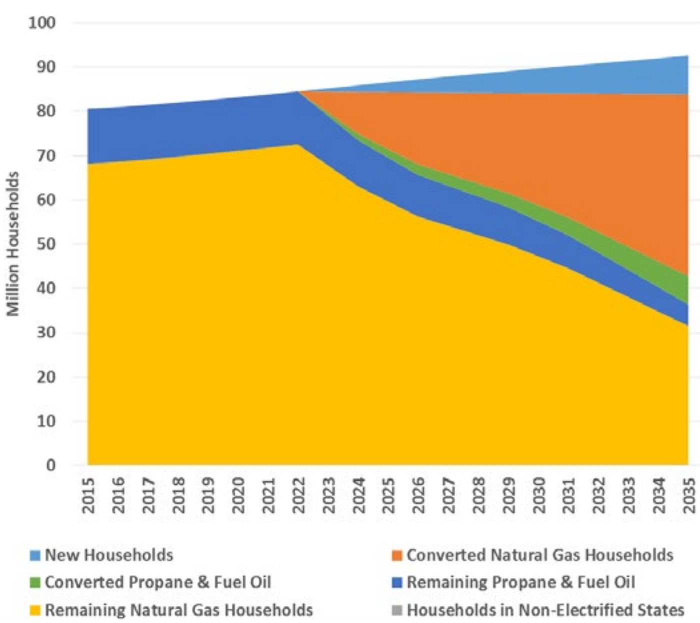
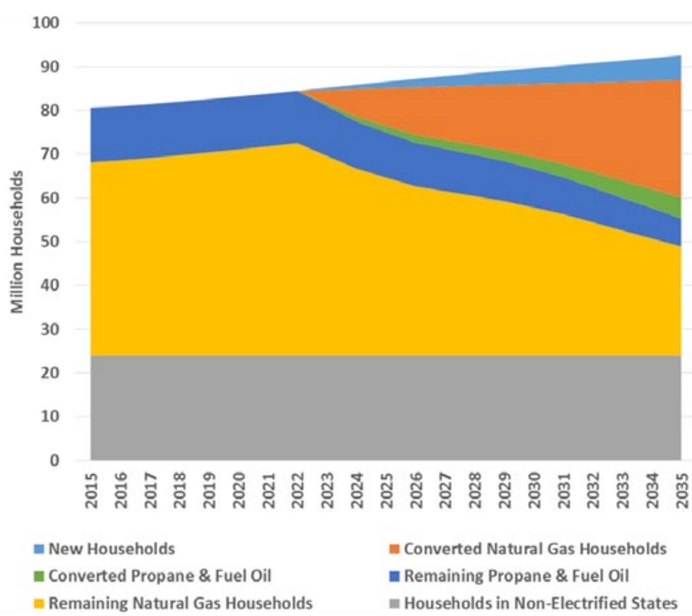


Figure 2-4:
Market-Based Generation Case Household Conversions



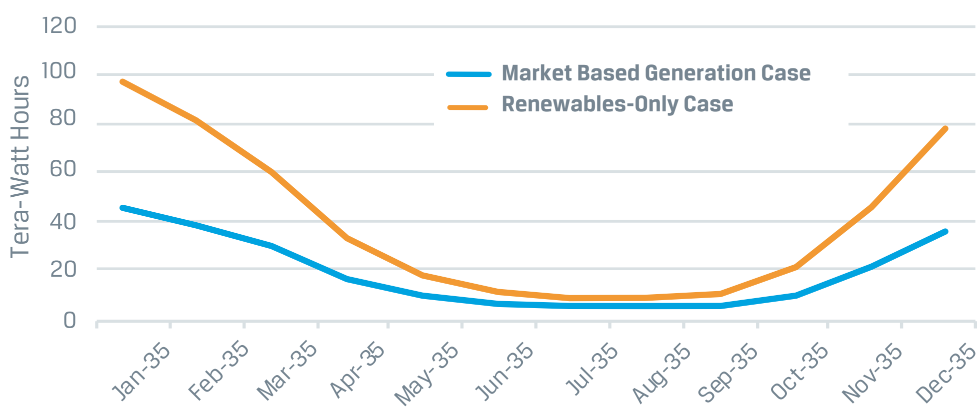
2.4 Impacts on Electricity Consumption and Demand Profiles

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



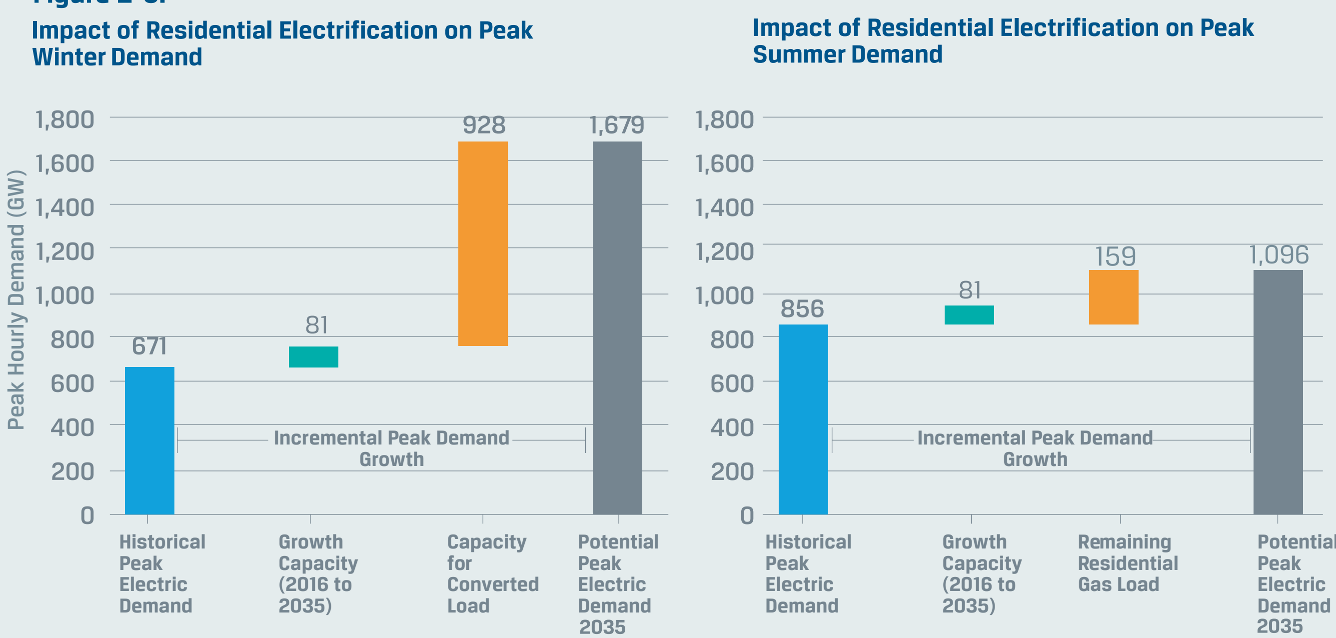
[11] See Appendix A for an explanation of this in the Heating System Efficiency Assumption Section

- **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.

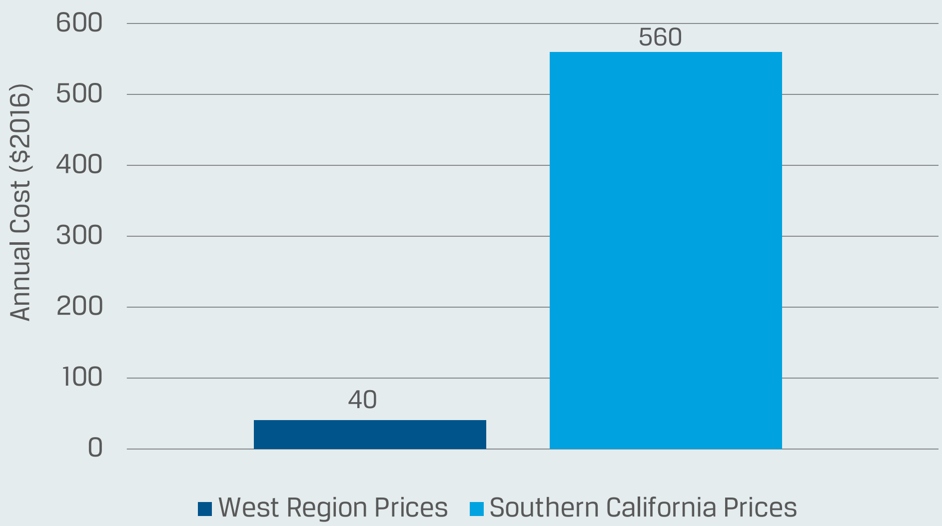
Given the complexity of the issues surrounding residential electrification policies, this study made a number of simplifying assumptions. For instance, this study assumed that all residential households were similar to a national average single-family household, despite the large number of multi-residence 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



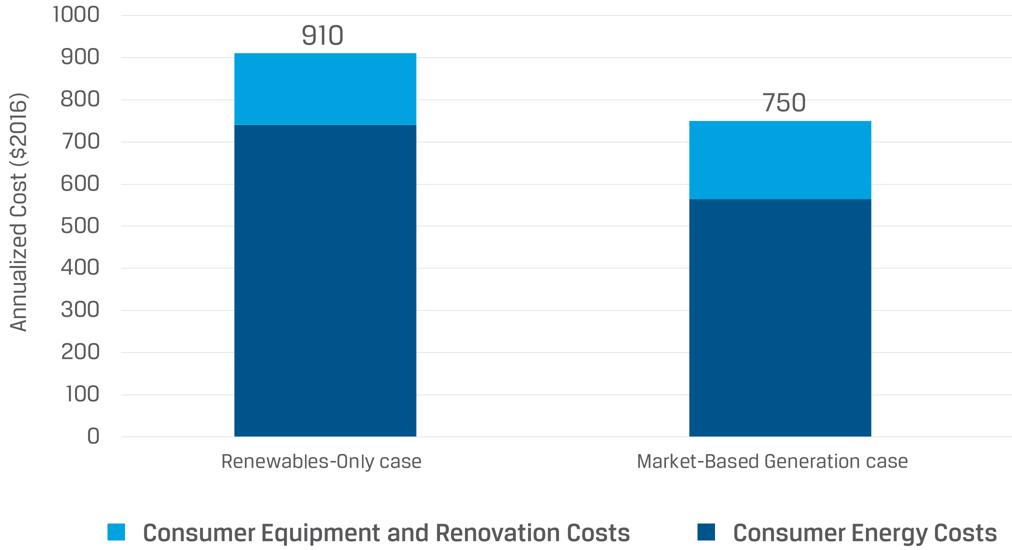
While the study methodology can be applied at the state or utility service territory level, this was beyond the scope of the AGA study. In addition, this type of more localized study approach would also need to consider many costs that were beyond the scope of the study, such as electric distribution 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.

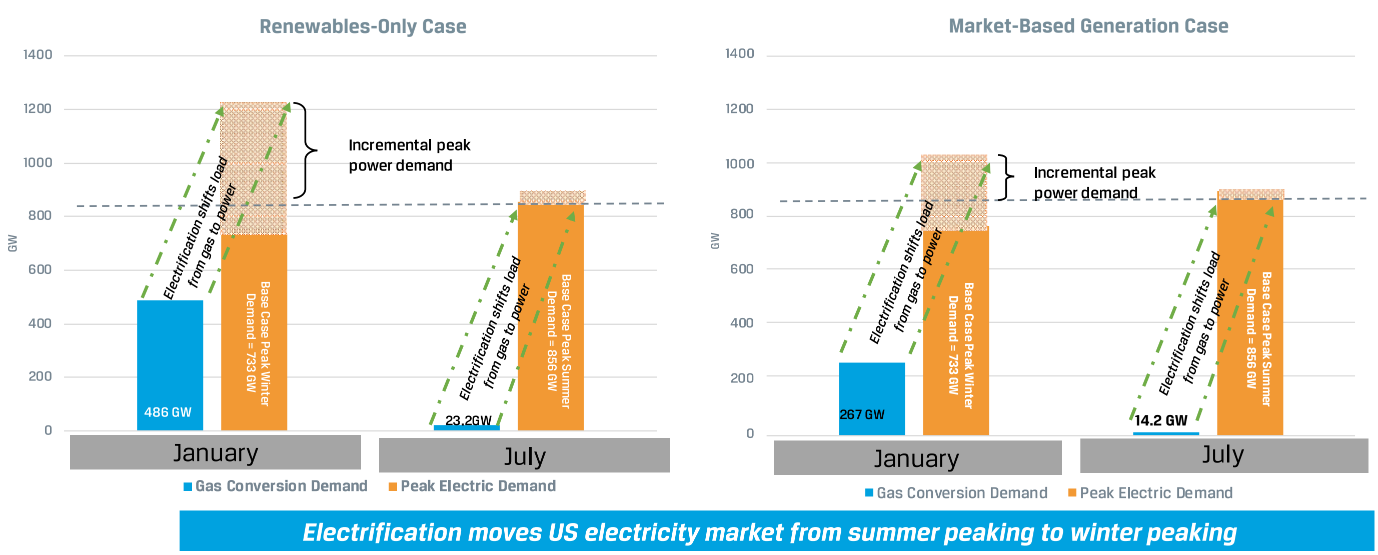
The Reference Case applied the assumptions from the EIA AEO 2017 Reference case, including the Clean Power Plan (CPP).[20] This reference case was calibrated to the EIA results with respect to emissions, total generation mix, levels of total renewable generation, and the mix of newly installed generation 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



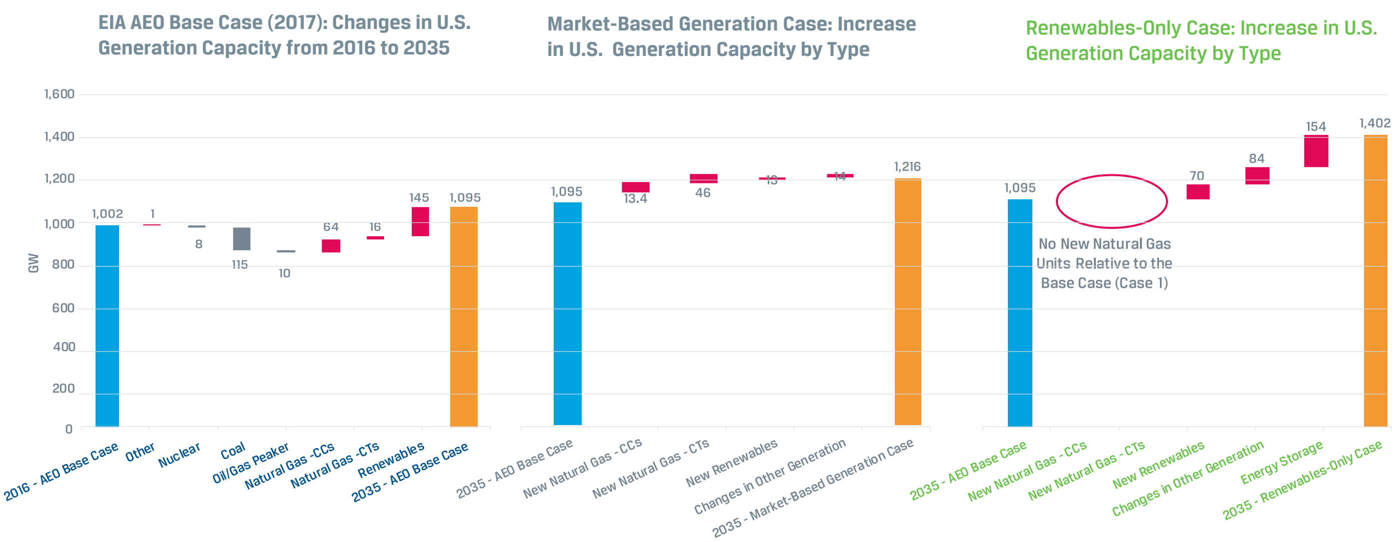
[20] The CPP was put on hold and was not included in the EIA's 2018 AEO Reference Case Assumptions but constitutes a more aggressive environmental case for this analysis.

[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.

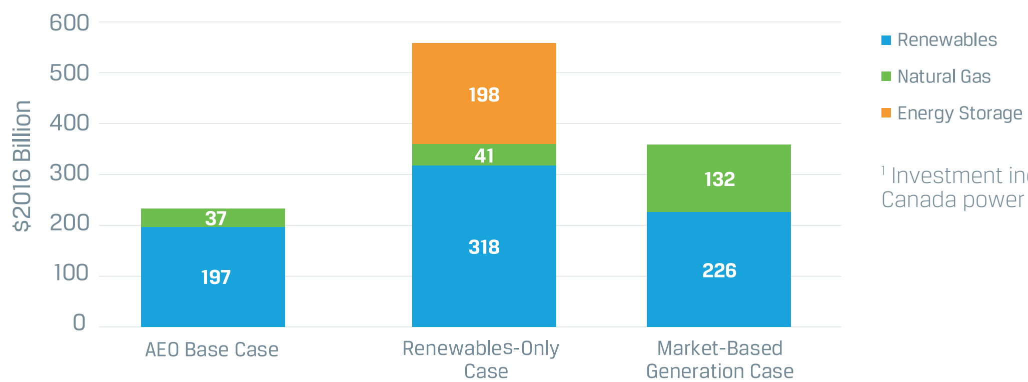
In the Reference Case, the 84 GW of retired capacity was replaced with higher efficiency, lower emitting natural gas combined cycle capacity. In the Renewables-Only Case, we did not allow these units to be replaced with new gas-fired units, which resulted in a delay in the retirement of these units. 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)

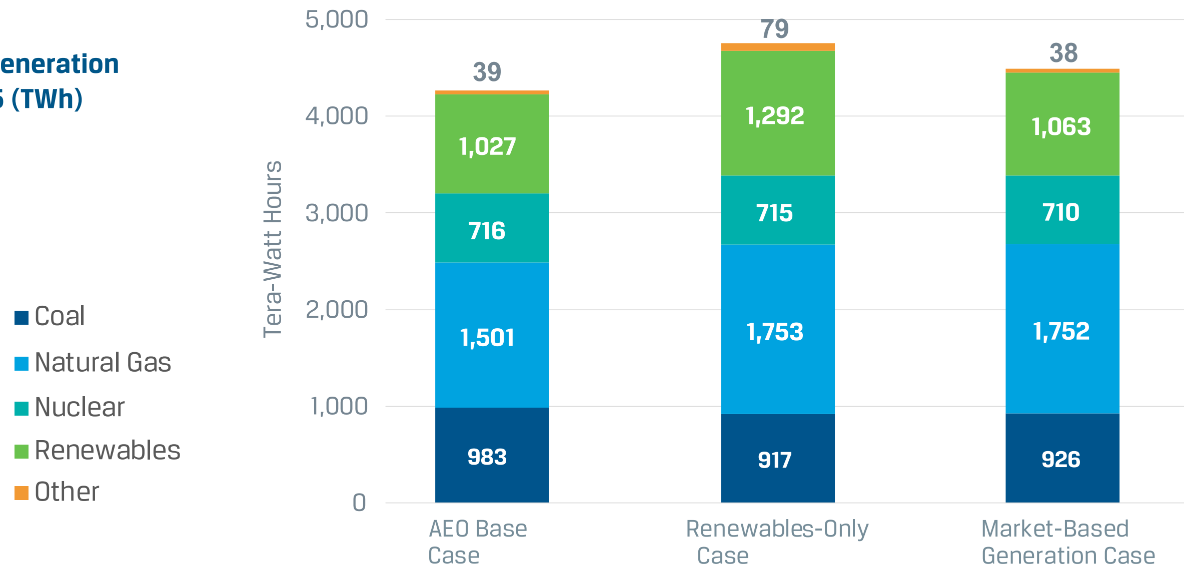
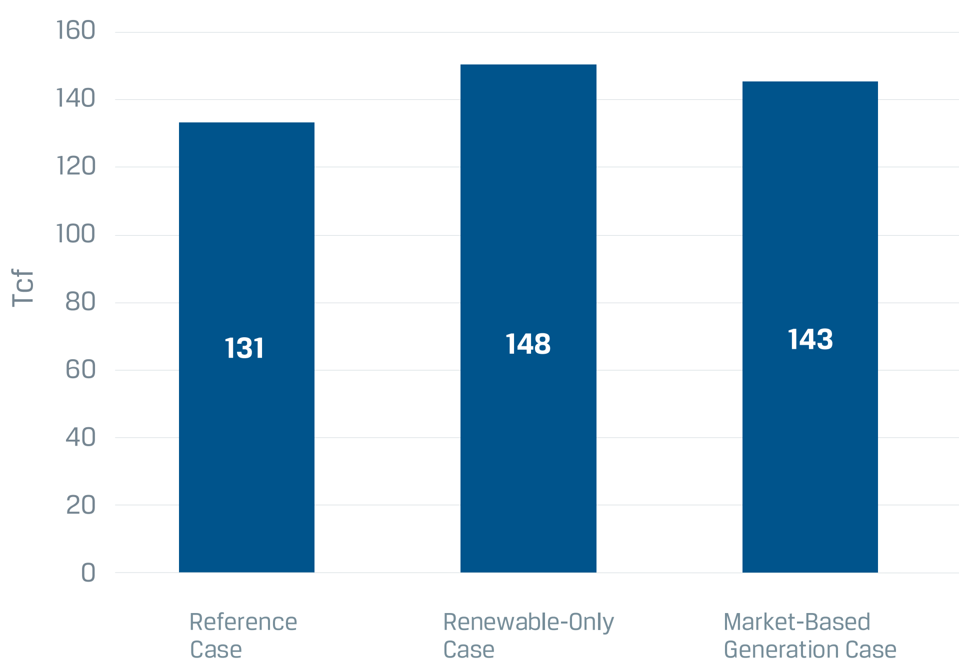


Figure 3-5 shows the gas consumption for power generation in the three cases. Natural gas consumption for electricity production increases in both policy cases as electricity generation increases to meet the increased demand for electric space and water heating loads. This is true even in the Renewables-Only 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

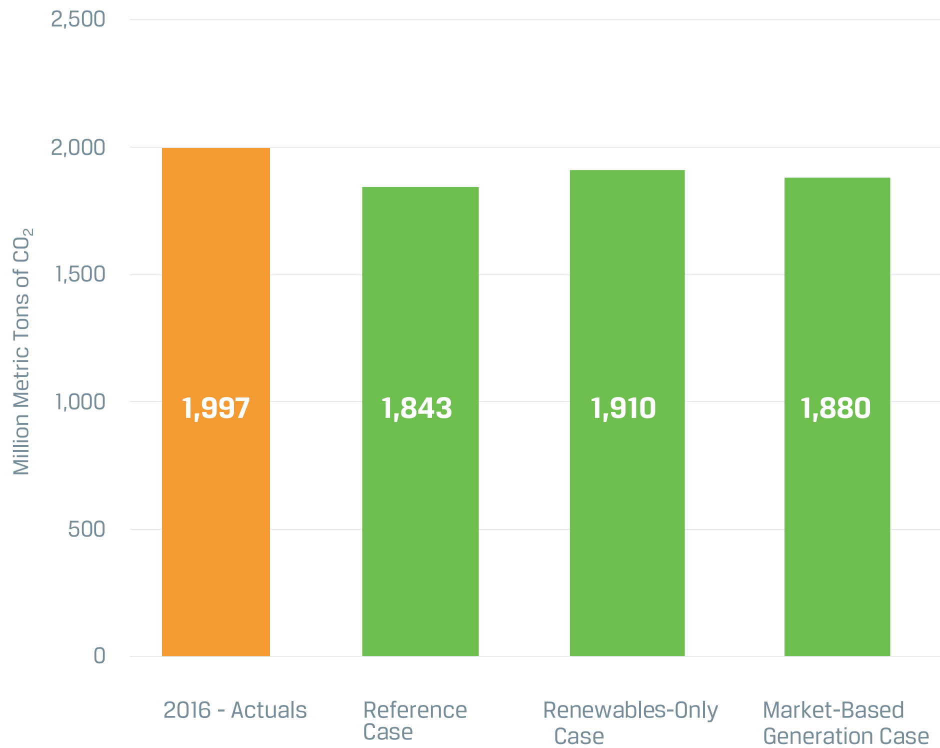


3.1.4 Impact of Policy Driven Residential Electrification on Power Sector CO_2 Emissions

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

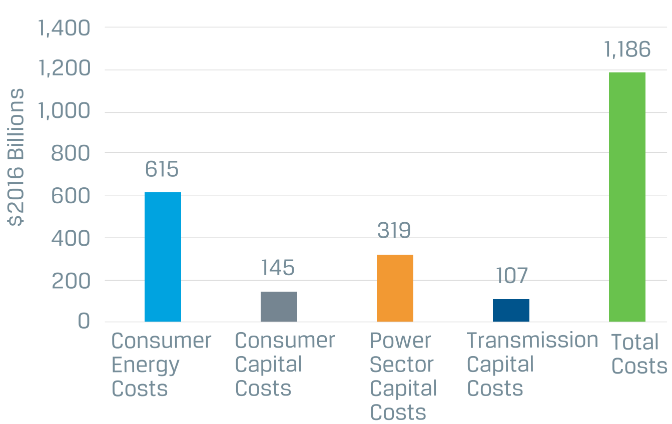
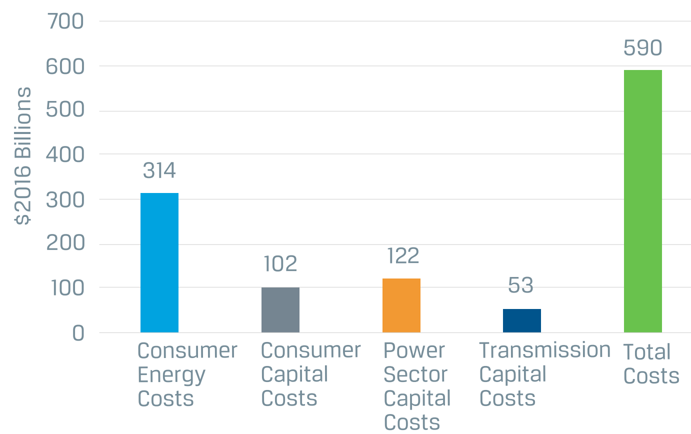


Figure 4-2:
Total Cost of Market-Based Generation Case by Sector



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]

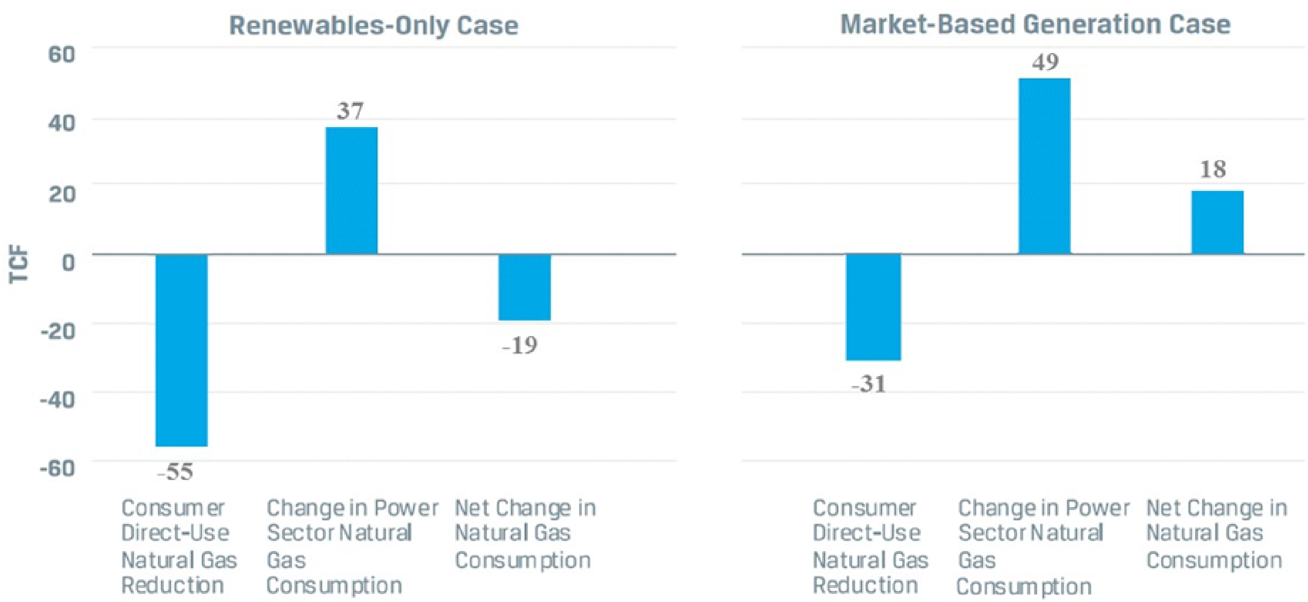
Region	Renewables-Only Case		Market-Based Generation Case	
	Cumulative Change in Costs Per Converted Household	Annualized Change in Costs Per Converted Household	Cumulative Change in Costs Per Converted Household	Annualized Change in Costs Per Converted Household
East Coast	18,440	1,240	16,550	1,110
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.

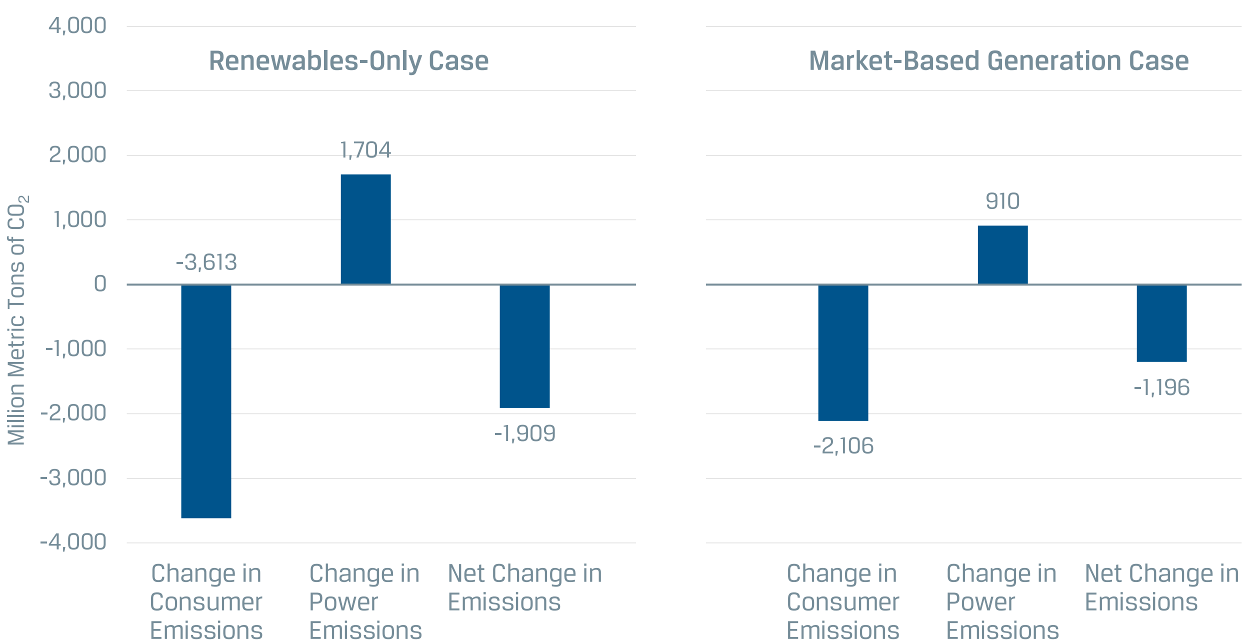
4.4 Net Environmental Impacts

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.

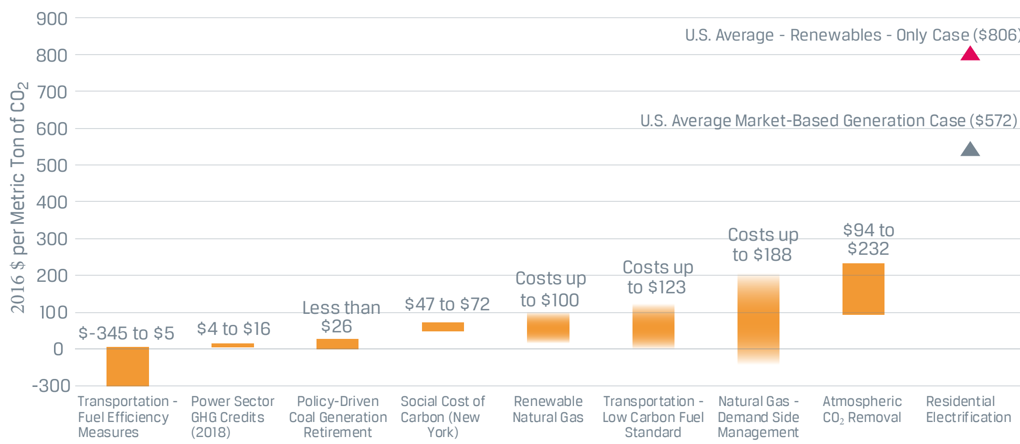
The growth in peak winter demand will also require incremental investments in the transmission and distribution systems. While this study includes an estimate for the required incremental investment in transmission capacity, it was beyond the scope of the study to assess the potential requirements for additional electric distribution capacity.

5.3 Cost-Effectiveness of Residential Electrification as a Greenhouse Gas Emissions Reduction Policy

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

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]



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 $)

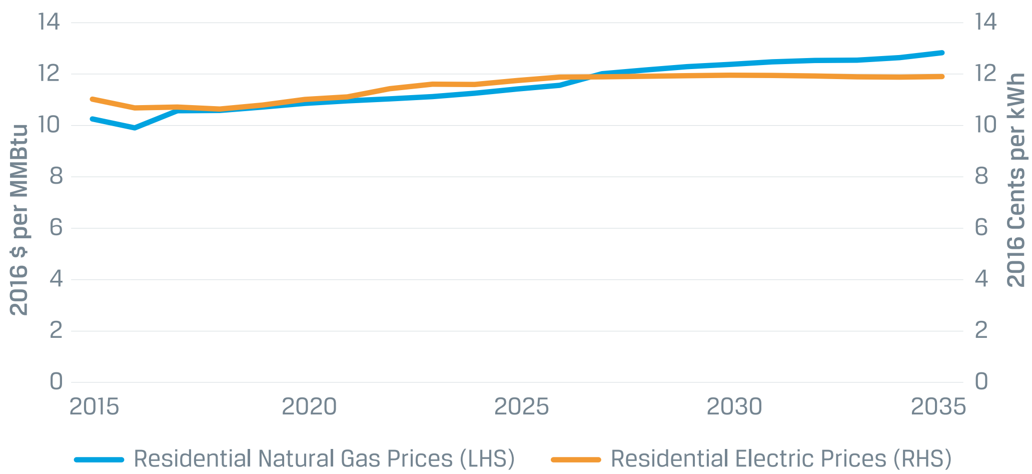


Exhibit A-2: Regional Residential Natural Gas and Electric Rates (Real 2016 $)[1]

	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

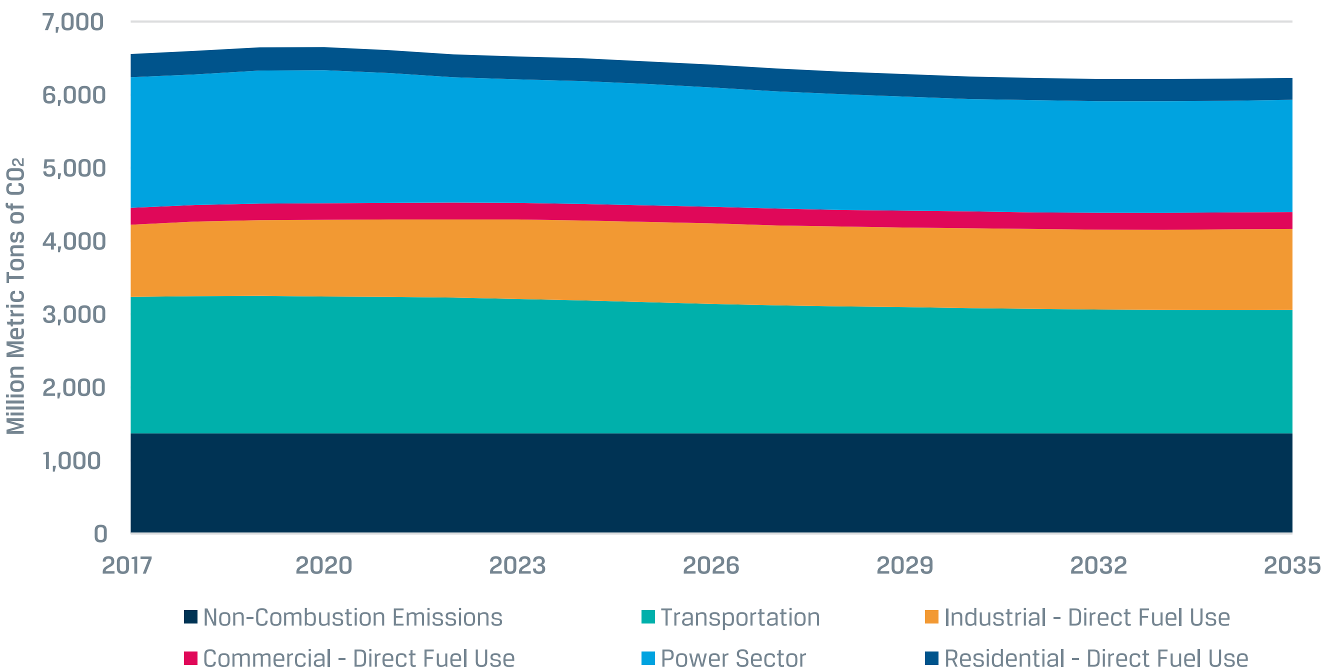
The impact of the residential electrification policies on CO_2 emissions are estimated based on the impact of the residential electrification policies on energy consumption in the residential and power generation sectors relative to the Base Case. The following fuel emissions factors are used to estimate 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.

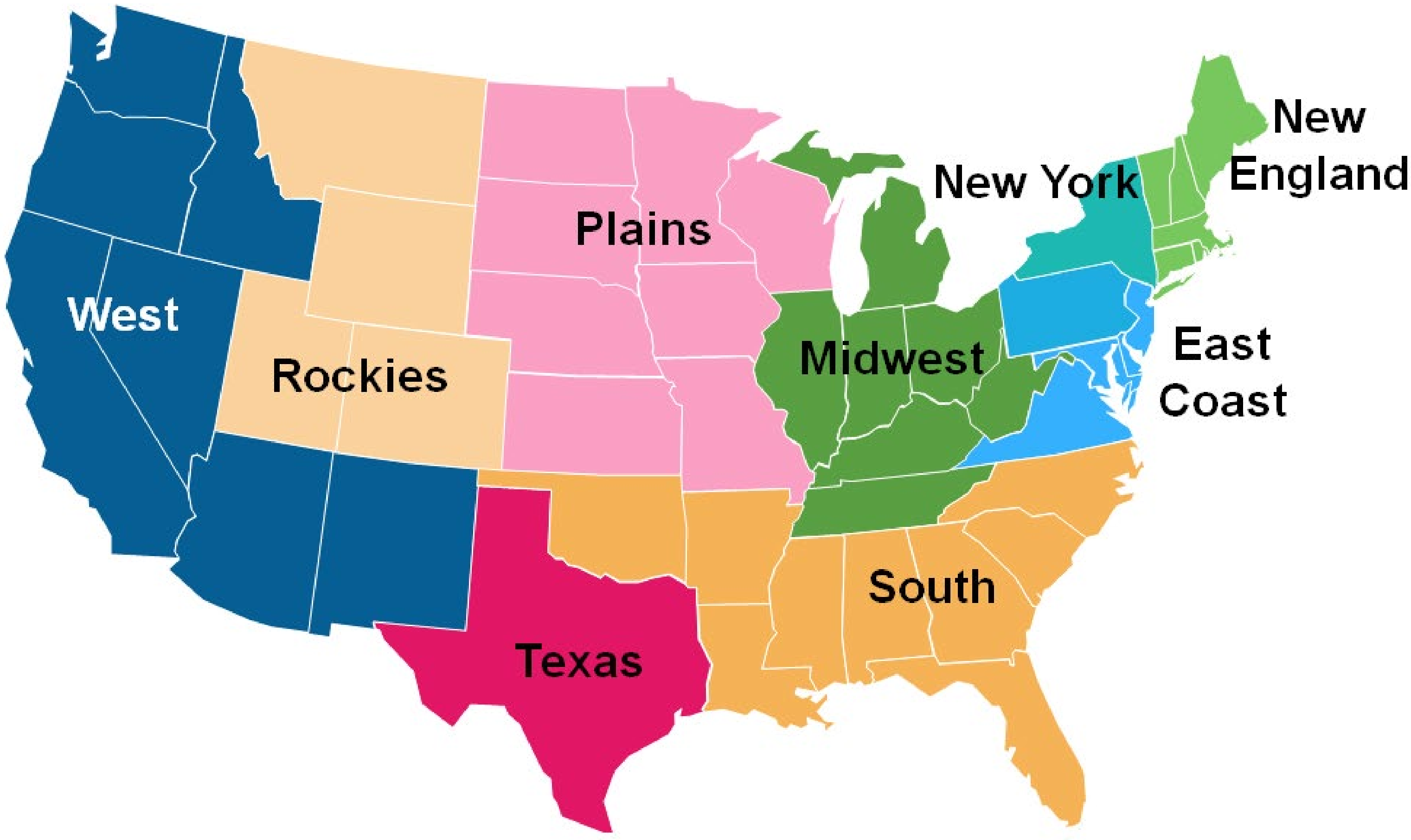
- The peak day design sendout for water and gas heating load is created in order to estimate peak winter period electric demand impacts of converting residential households to electricity. To calculate the peak day natural gas demand levels, the study uses Heating Degree Days (HDDs) from the coldest 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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AGA
100 YEARS

Implications of **Policy-Driven Residential Electrification**

An American Gas Association Study
prepared by ICF

ATTACHMENT B

Electrifying the Columbus, Ohio Metro Area's Building Stock – Economic and Power Market Impacts

August 2020

Electrifying the Columbus, Ohio Metro Area's Building Stock – Economic and Power Market Impacts

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EXPERTS WITH IMPACT™

FTI™ CONSULTING

Table of Contents

FTI CONSULTING

Main Takeaways

- FTI Consulting ("FTI") modeled the impacts of a policy where all residential and commercial structures in the Columbus, Ohio metropolitan area ("Columbus MSA") would install electric space heating and water heaters, electric cooking and drying equipment, and convert all other appliances and energy needs from natural gas to electricity.
- According to inputs provided by the American Gas Association ("AGA"), the 20-year cost of ownership for a representative home with electrical equipment is between $27,200 and $31,000 – costs with high-efficiency natural gas would be $18,400. For a representative customer in the commercial sector, the 20-year cost of ownership for electrical equipment would be $167,200 compared to only $64,200 for gas-fired equipment.
- Converting the Columbus MSA's building stock to electricity would increase the load for the power sector, which would lead to slightly higher electricity prices (<1.2% in all years for the zone home to Columbus). Customers in the Midwest, Appalachia, and the Mid-Atlantic would face higher prices for electricity. Increased load would engender capacity additions of either 1.2 gigawatts ("GW") of natural gas combined cycle ("NGCC") units or, if the incremental builds must be renewables, then 2.0 GW of photovoltaic solar capacity.
- A critical question is if this policy would reduce emissions and, if so, at what cost. With carbon dioxide ("CO2"), we project emissions would total 52.9 million metric tons ("MMT") from 2021 to 2040 when the present fleet of gas-fired equipment sees its replacement by high-efficiency gas. Electrifying this demand would emit 48.3 MMT in a "market-based" scenario with NGCC additions or 65.6 MMT in a "renewables-only" scenario with the solar additions, which are 4.6 MMT less (-8.7%) and 12.8 MMT more (24.2%) respectively than baseline.
- For nitrogen oxides ("NOx") from 2021 to 2040, baseline emissions would be 58,200 short tons. Market-based emissions would be 10,000 short tons, and renewables-only emissions would be 38,400 short tons.[1] For sulfur dioxide ("SO2") from 2021 to 2040, baseline emissions would be 500 short tons. Market-based emissions would be 5,000 short tons, and renewables-only emissions would be 38,600 short tons.[2] The proposed policy would increase CO2 emissions in the renewables-only scenario but decrease them in the market-based scenario. The policy would reduce NOx emissions yet at the cost of higher SO2 emissions.
- The higher costs from electrification for customers in the Columbus MSA would come to $7.4 billion from 2021 to 2040. That market-based scenario would reduce CO2 emissions, but it would come at a cost of $1,615 per metric ton of saved emissions.

[1] Market-based NOx emissions are 82.9% less than baseline NOx; renewables-only is 46.3% less than baseline
[2] Market-based SO2 emissions are 908.2% more than baseline SO2; renewables-only is 7,657.0% more than baseline

- Using benefit-cost valuations for CO2, NOx, and SO2, the market-based scenario would create benefits of $377.5 million versus $7.4 billion in costs from 2021 to 2040. At a 5% discount rate, every $154 in higher costs would produce $1 in benefits. The renewables-only scenario would be counterproductive because it increases emissions, which translates to $2 billion in additional costs when monetized. These calculations include only the costs borne by the Columbus MSA and not the costs borne by customers throughout the region.
- The higher cost of living and higher cost of doing business would have negative implications within the Columbus MSA's economy. Consumers, facing higher utility bills and higher costs passed onto them from commercial establishments, would economize their spending on consumer staples (e.g., prepared food and retail products).
- By 2040, the Columbus MSA's economy would have 5,700 fewer jobs and $271 million less in GDP under electrification compared to a baseline of replacing the existing fleet of gas-fired equipment with high-efficiency gas through natural attrition. Impacts in the same vein would continue thereafter because the higher costs would continue.

Executive Summary

AGA engaged FTI to examine the potential impacts from converting the housing and commercial building stocks of the Columbus MSA from natural gas to electricity for their energy needs over the course of the next 20 years. This report examines the upshot of these conversions on power markets within Ohio and the Midwest and to the economy of the Columbus MSA.

Methodology and Approach

FTI approached this research with three primary tools: (1.) inputs from AGA, (2.) the PLEXOS model, and (3.) the IMPLAN model. Major inputs from AGA included the number of existing residential homes and commercial structures to convert plus new builds to adopt either high-efficiency natural gas or electricity in the next two decades. It also provided the upfront equipment and installation costs and the long-term maintenance and energy costs for high-efficiency natural gas and electricity and data describing the seasonal patterns of heating demand for the Columbus MSA.

According to these inputs, over 800,000 residential homes and commercial buildings in the Columbus MSA would have heating equipment and appliance installations from 2021 to 2040. ES Table 1 shows the exact numbers split between structure type and existing or new:

ES Table 1 – Annual and total new builds and conversions

Structure Classification	New Builds (annual)	Conversions (annual)	New Builds (2021-2040)	Total Conversions (2021-2040)
Residential	6,650	30,840	131,000	616,760
Commercial	760	2,410	15,220	48,180

The main thrust and driving force behind the results comes from inputs regarding the costs to buy, to install, and to operate the types of equipment. According to inputs from AGA, the 20-year lifecycle costs (in 2018 dollars) would be $18,411 for a high-efficiency natural gas home heating system versus $27,202 to $30,962 for an electric home heating system. The latter range depends on if homes need updated electric panels to handle higher amperage. For commercial customers, their average costs over the same period would be $64,240 with gas and $167,160 with electricity.

A net increase in utility bills for residential customers would reduce their purchasing power, which impacts the local economy and economic sectors dependent on consumer expenditures. The higher costs for the commercial sector would mean reduced competitiveness or higher costs passed along to their customers – again negatively affecting households' purchasing power.

FTI simulated the economic impact of these three effects (more demand for electricity, less demand for gas, and higher costs) in IMPLAN. IMPLAN is a widely applied model for answering questions on impacts from policy changes, and a diagram for it is in Appendix A.

The conversion of hundreds of thousands of homes and tens of thousands of commercial structures over to electric heating systems would increase total and peak electricity load for the Columbus MSA. To assess these conversions and impacts on wholesale electricity markets in Ohio and the Midwest, FTI applied its PLEXOS model of the North American electrical system.

PLEXOS determined the impacts on plant additions and plant retirements from the additional load as well as effects on wholesale prices for the zone encompassing Columbus. FTI integrated the outputs from PLEXOS for electricity prices into the IMPLAN inputs, as well.

FTI modeled a Base Case without any additional heating electrification and two scenarios in PLEXOS. For the first scenario, the market could respond to the load without other assumptions or restrictions ("market-based" or "MB"). In the second scenario, incremental capacity must be solar or wind only ("renewables-only" or "RO") without battery storage. The differences between these simulations produced the change in various types of emissions associated with electrification.

For the remainder of the Executive Summary, we discuss the results of the power market analysis, results for emissions, and then the results for the economic impact analysis. When then present a longer narrative and documentation of our inputs and assumptions.

Results

Power Market Results

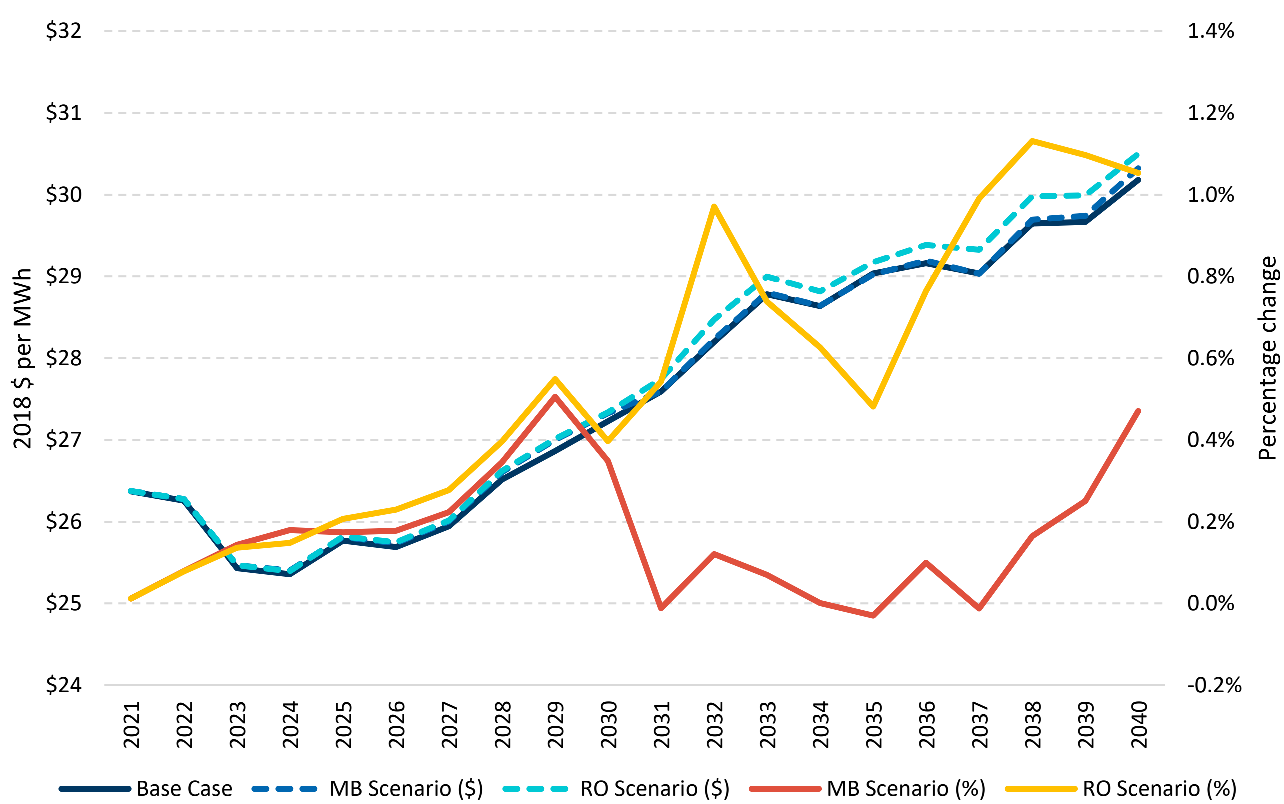
ES Table 2 summarizes the capacity expansion results for the two scenarios. In the MB Scenario, the increased energy and peak load induces 1.2 GW of NGCC builds relative to the Base Case. In the RO Scenario, capacity additions would be 2.0 GW of solar. The combination of the higher load and the operation of these plants would, in turn, influence market prices.

ES Table 2 – Capacity expansion from PLEXOS simulations for PJM (2021 to 2040, gigawatts)

Scenario versus Base Case	Solar	Wind	Biomass	NGCC	Thermal Retirements	Net Additions
MB Scenario	0.0	0.0	0.0	1.2	0.0	1.2
RO Scenario	2.0	-0.1	0.0	0.0	0.0	1.9

ES Figure 1 shows the electricity price forecast for the American Electric Power ("AEP") zone in central Ohio and neighboring states. Electricity prices would remain close to one another but increase in the MB Scenario and the RO Scenario. The RO Scenario would have the highest prices throughout the modeling horizon. In MB Scenario, prices are higher only in the 2020s and the late 2030s. The reason is that the additional NGCC builds in the MB Scenario from ES Table 2 would be flexible resources with low heat rates and dispatch costs, and hence their dispatch into the market throughout the year would help to hold average prices down despite the increase in the load.

ES Figure 1 – Annual AEP wholesale electricity price (2018 $)



We also included inputs related to changing electricity prices (the ones from ES Figure 1) in IMPLAN. The general effect of affecting households' purchasing power was the same.

ES Table 3 shows the difference in emissions between the Base Case and the two scenarios. PLEXOS produces reduces for CO2, NOx, and SO2. Relative to the Base Case, the MB Scenario would reduce CO2 emissions and the RO Scenario would increase them. Both scenarios would reduce NOx when compared to the Base Case, though the reduced NOx would come at an increase in SO2 of 4,500 short tons in the MB Scenario and 38,100 short tons in the RO Scenario.

ES Table 3 – Emissions results (2021 to 2040)

Scenario	CO2 (millions of metric tons)	NOx (thousands of short tons)	SO2 (thousands of short tons)
Base Case	52.9	58.2	0.5
MB Scenario	48.3	10.0	5.0
RO Scenario	65.6	31.3	38.4
MB Scenario versus Base Case	-4.6 (-8.7%)	-48.2 (-82.9%)	4.5 (908.2%)
RO Scenario versus Base Case	12.8 (24.2%)	-26.9 (-46.3%)	38.1 (7,657.0%)

For all three compounds, the MB Scenario would have lower emissions than the RO Scenario. Those results might seem counterintuitive, though they follow from electricity market dynamics. The 1.2 GW of new NGCC in the MB Scenario would produce emissions, but it would operate at a higher capacity factor and in more reliably high-load hours than the 2.0 GW of solar in the RO Scenario. NGCC would therefore be more effective at displacing existing coal generation compared to the incremental solar. The larger quantities of NOx and SO2 emissions in the RO Scenario relative to the RO Scenario further demonstrates the solar displaces less coal generation than the NGCC.

ES Table 4 shows the change in emissions from ES Table 3 monetized with federal valuations for CO2 ($51 per metric ton), NOx ($6,704 per short ton), and SO2 ($39,599 per short ton).

ES Table 4 – Valuation of the increased or decreased emissions in the scenarios (2018 $ millions)

Scenario	CO2	NOx	SO2	Total
MB Scenario versus Base Case	$233.1	$323.4	-$179.0	$377.5
RO Scenario versus Base Case	-$649.5	$180.7	-$1,508.8	-$1,977.6

The RO Scenario, despite its lower NOx emissions than the Base Case, would have a negative value in terms of saved emissions because it would increase CO2 and SO2 emissions. Compared to the Base Case, the MB Scenario would increase SO2 emissions yet decrease CO2 and NOx emissions, which contributes to its positive overall valuation ($377.5 million) in ES Table 4.

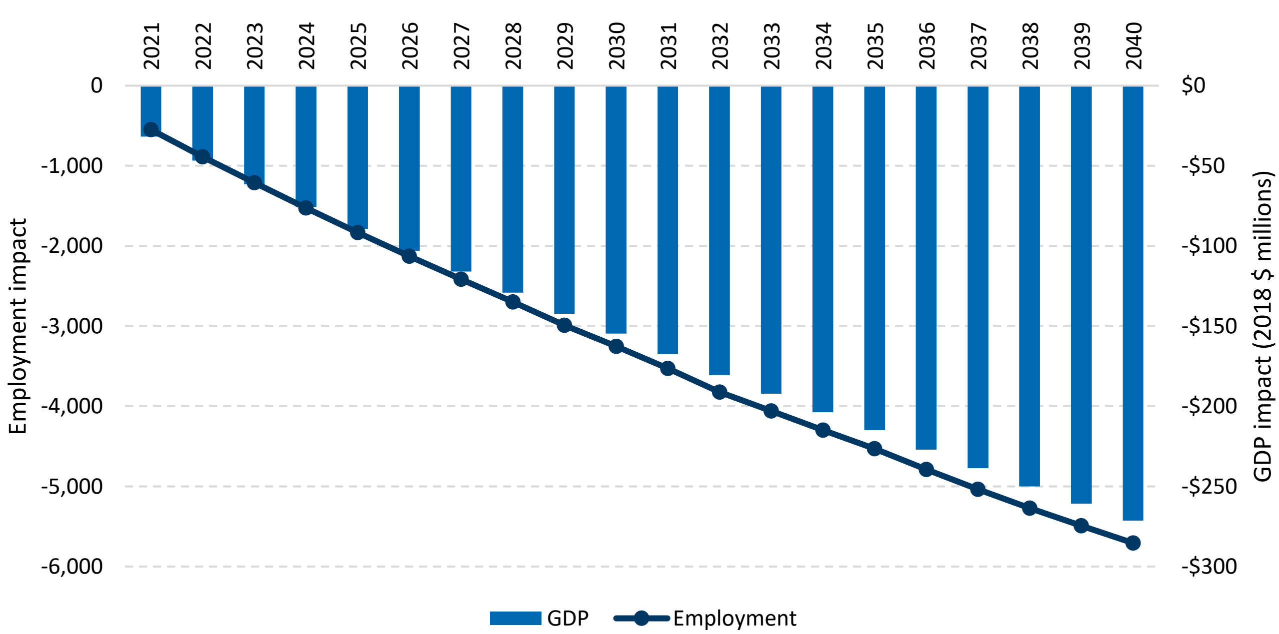
The RO Scenario would be counterproductive towards reducing emissions. The MB Scenario would achieve emissions reductions, though only at extremely high costs. For the $381.8 million worth of saved emissions from ES Table 4, customer costs in the Columbus MSA would increase by $7.4 billion to purchase, install, maintain, and operate electric equipment instead of upgrading to high-efficiency gas-fired equivalents. These costs are for the Columbus MSA only and do not include higher electricity prices paid by customers across the Midwest, Appalachia, and the Mid-Atlantic in territories for the utilities participating in the PJM Interconnection, LLC ("PJM").

For CO2 alone in the MB Scenario, the cost for the Columbus MSA for the saved emissions from ES Table 4 would be $1,615 per metric ton. Including NOx and SO2 alongside CO2 and with a 5% discount rate, every $154 in higher costs would yield $1 in benefits. Most of the emissions reductions in ES Table 4 would come in the 2030s, reducing their present value.

Economic Impact Results

Electrifying residential and commercial building stock would have a negative impact on the economy of the Columbus MSA over time. The incremental end-consumer expenditures on electricity as compared to gas expenditures for high-efficiency natural gas heating would gradually reduce expenditures on other household goods and services. The commercial customers facing the same higher costs would exacerbate the situation by passing higher costs along to customers.

ES Figure 2 – Economic impact of electrifying the Columbus MSA



ES Figure 2 shows results for employment and gross domestic product ("GDP"). As more homes and structures electrify, the economic impacts would become increasingly negative.

While the aggregate results from ES Figure 2 describe an overall negative impact, the distribution of those impacts would not be equal across economic sectors.

Electrification would increase the employment associated with the electric power and construction sectors and decrease the employment associated with natural gas distribution and pipelines. At the same time, the higher cost of living and the higher cost of doing business due to the electrification would decrease real incomes and purchasing power across the Columbus MSA, which leads to the reduced employment for the service sectors in ES Table 5.

ES Table 5 – Employment impact by economic sector

Economic Sector	2025	2030	2035	2040
Electric Power G, T, and D[3]	240	430	610	770
Construction	90	120	160	180
S&L[4] Government (Non-Education)	0	10	10	20
Coal Mining	0	0	0	0
Other Mining	0	0	0	0
S&L Government (Education)	0	0	0	0
Water and Sewage	0	0	0	0
Agriculture and Forestry	0	0	-10	-10
Federal Government	-10	-10	-20	-20
Manufacturing	-10	-10	-20	-20
Oil and Natural Gas Extraction	-10	-20	-30	-40
Information	-30	-50	-70	-90
Wholesale	-50	-100	-130	-170
Arts, Entertainment, and Recreation	-60	-110	-150	-180
Transportation and Logistics	-70	-130	-180	-230
Private Education	-80	-140	-200	-250
Natural Gas Distribution and Pipelines	-160	-290	-410	-510
Other Personal Services	-190	-320	-450	-560
Accommodation and Food Service	-230	-400	-550	-690
Finance, Insurance, and Real Estate	-240	-430	-610	-770
Retail	-250	-440	-620	-780
Professional and Business Services	-310	-550	-770	-970
Healthcare and Social Assistance	-460	-800	-1,100	-1,380
TOTAL	-1,830	-3,250	-4,530	-5,710

[3] Electric power generation, transmission, and distribution
[4] State and local government

Introduction

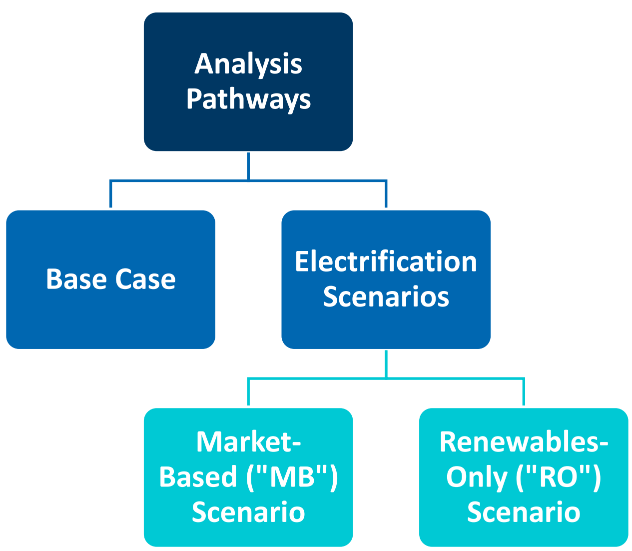
The American Gas Association ("AGA") engaged FTI Consulting, Inc. to assess impacts to the Columbus, Ohio metropolitan area (a 10-county region of central Ohio)[5] from electrifying its residential and commercial building stock, including needs for heating, cooking, and hot water.

According to data from the American Housing Survey ("AHS"),[6] most homes in Ohio and by extension the Columbus MSA use natural gas as their primary heating and cooking fuel. We have examined two situations for the heating equipment and appliances needs of residential and commercial buildings in the Columbus MSA. In our "Base Case," buildings relying on gas in the Columbus MSA would convert to newer and high-efficiency gas equipment over the next 20 years. Our projected new builds would also use high-efficiency gas. In our electrification analysis, new builds immediately use electricity for their heating and appliance needs, and the stock of existing buildings would convert from natural gas to electricity for their energy needs over the next 20 years.

The electrification would increase higher peak load and total energy in the American Electric Power ("AEP") zone of PJM. AEP serves most of the Columbus MSA for its electricity demand. We used a model of the system called PLEXOS to examine what the load would mean for wholesale electricity markets under two scenarios. In the "Market-Based Scenario," the electricity market could add any type of generation making economic sense to serve higher load. In the "Renewables-Only Scenario," we restricted any incremental additions to solar and wind plants only.

Figure 1 organizes the Base Case and our two scenarios for the electricity market modeling.

Figure 1 – Summary of the scenarios for analysis



[5] A 10-county region of central Ohio including Delaware, Fairfield, Franklin, Hocking, Licking, Madison, Morrow, Perry, Pickaway, and Union Counties

[6] "American Housing Survey," *U.S. Census Bureau*, https://www.census.gov/programs-surveys/ahs.html

The main body of this report describes the Base Case, scenarios, their inputs, and their assumptions with additional details. We then describe the impacts of electrifying the Columbus MSA's residential and commercial building stock with the results from simulations in PLEXOS and IMPLAN.[7] IMPLAN is an "input-output" model of regional economies designed to show the impacts of changes to economies and public policy. Where appropriate, we have included appendices with more detailed data tables documenting our results and describing PLEXOS and IMPLAN.

Methodology and Approach

AGA provided the inputs and assumptions underlying the FTI simulations in PLEXOS and IMPLAN.[8] AGA based its analysis on federal and regional data sources, such as the U.S. Census Bureau, and previous research on the relative cost and efficiency of natural gas-fired appliances and heating equipment relative to using electricity-powered alternatives for the same purposes.

Number of New Builds and Conversions

The first major consideration across the analysis was the number of homes and commercial buildings to convert to high-efficiency gas (in the Base Case) or electricity (under electrification). On top of these are new homes and structures being built, which could have either high-efficiency gas (in the Base Case) or electricity (in the two electrification scenarios). Table 1 describes our inputs for new builds and conversions annually and for the next 20 years.

Table 1 – Annual and total new builds and conversions

Structure Classification	New Builds (annual)	Conversions (annual)	New Builds (2021-2040)	Total Conversions (2021-2040)
Residential	6,650	30,840	131,000	616,760
Commercial	760	2,410	15,220	48,180

We chose 20 years as our horizon because it is a reasonable estimate of the service life for equipment of this nature. We are not analyzing any "early" conversions and instead assume upgrades to new gas or electrified equipment comes as the existing fleet naturally turns over.

The Base Case and scenarios would require the conversion of 616,760 homes and 48,180 commercial buildings over the course of 20 years, which are estimates of the size of the stock for the Columbus MSA in 2020. These conversions would proceed in a linear fashion with 5% of the initial total having conversion each year. On top of these would be 6,650 residential new builds and 760 commercial new builds each year, eventually adding to the aggregate totals in Table 1.

[7] "Where It All Started," *IMPLAN*, https://implan.com/history/
[8] For diagrams of PLEXOS and IMPLAN, please see Appendix A

In addition, many older homes would require upgrades to their electrical panel to handle the electric heating equipment and appliances imagined under electrification. Our estimate is 32% of older homes (the ones built before 1960) in the Columbus MSA would require these upgrades. The plan for the electrification would require that 9,870 homes year and 197,360 overall homes from 2021 to 2040 would require modernizing their panel to higher amperage.

Figure 2 shows a graphical representation of the data from Table 1 for residential structures. Figure 3 displays the equivalent data but for commercial structures. Under both situations, existing structures begin with gas-fired equipment at present efficiency. For the Base Case, existing structures would convert to new, high-efficiency gas equipment over time. New builds would also come online with high-efficiency gas equipment. For the electrification, the conversions and new builds would instead come up to speed with electrified equipment and appliances.

Figure 2 – Existing residential structures, conversions, and new builds (thousands)

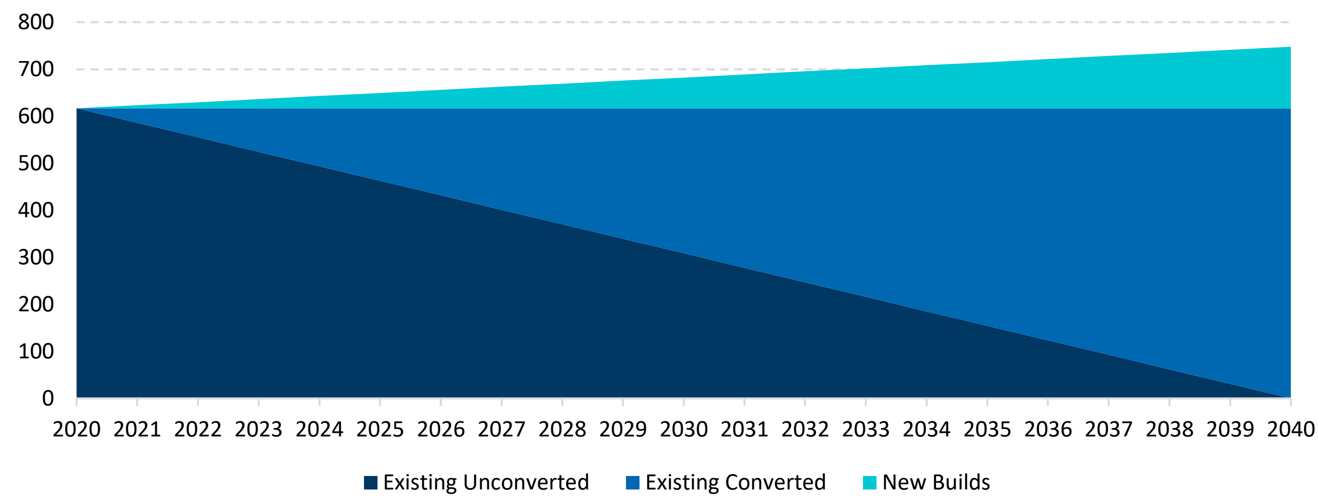
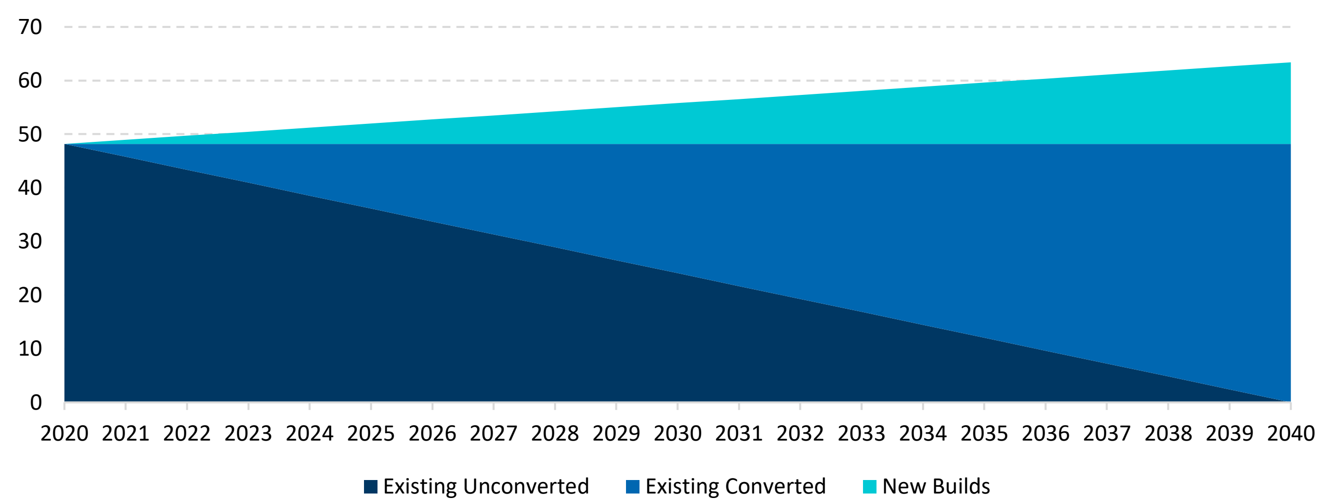


Figure 3 – Existing commercial structures, conversions, and new builds (thousands)



Assumptions and Inputs for Modeling Conversions

AGA provided FTI with inputs and assumptions for the cost of new gas-fired equipment, the cost of new electrical equipment, and the ongoing energy costs to operate them.

The AGA model of residential and commercial natural gas customers is derived from the U.S. Energy Information Administration ("EIA") and its data sources, including its monthly consumption and its customer count data for 2018. Using these sources, AGA estimated a space heating load by subtracting the average summer consumption from total annual consumption. Hourly heating load data comes from allocating the monthly demand load by hourly heating degree data.

Limiting the input data to 2018 was a deliberate choice. That year had nominal winter weather both locally and nationally compared to 30-year heating degree day averages. Additionally, by using a single year for reference instead of a long-term average the peak of the peak energy demand for the coldest hours of the year would be present in the shape data. Preserving this facet of the shape helps provide the electricity sector modeling with more realistic conditions.

Heat pump performance on the handbook produced by the American Society of Heating, Refrigerating, and Air-Conditioning Engineers ("ASHRAE"). This analysis assumes a nameplate efficiency of 300% at 35°F and a maximum output of 100% of the demand load. The maximum output and the efficiency at 35°F can increase though only by oversizing the unit and thereby increasing costs to consumers paying to purchase, install, maintain, and operate the unit.

To account for a wider range of air compressor abilities, if the outdoor air temperature remained above -27°F, the heat pump would continue to function. However, its performance and its maximum output would decrease as the temperature drops from -35°F. These assumptions are consistent with the ASHRAE handbook for heat pump operations. The model determined approximately 25% of space heating demand comes from backup resistance. The model also determined the actual efficiency for modeled representative heat pumps in the Columbus MSA to be 230%.

Customers converting to heat pumps would install a 300% rated unit in exchange for a retired 80% efficient gas-fired unit along with a heat pump water heater and all-electric appliances. The baseload appliance performance derived from a regional weighted average developed using RECS 2015[9] and CBECS 2012[10] surveys. AGA found the average residential customer has a baseload efficiency of 73% and the average commercial customer has a baseload efficiency of 72%.

For residential customers, AGA assumed the average efficiency of heat pump water heaters had a minimum rating of 200% and, on average, all non-space heating appliances fit a profile of 178%. For

[9] "2015 Residential Energy Consumption Survey," *U.S. Energy Information Administration*, https://www.eia.gov/consumption/residential/data/2015/

[10] "2012 Commercial Buildings Energy Consumption Survey," *U.S. Energy Information Administration*, https://www.eia.gov/consumption/commercial/data/2012/

commercial customers, who have much greater needs for water heating and baseload, AGA used a conversion profile of 125% efficiency compared to a gas equivalent.

Table 2 and Table 3 summarize these inputs. Because commercial customers have widely diverging requirements for space heating capabilities, AGA did not evaluate the installation costs between gas furnaces and electric heat pumps for the commercial customer segment.

Table 2 – Summary of assumptions and inputs for residential conversions

Demand Category	Equipment Type	Efficiency	Annual Site Energy (MMBtu)	Annual Fuel Costs (2018 $)	Installation Costs (2018 $)	Equipment Costs (2018 $)
Space Heating	Gas Furnace	80%	70.3	$460	$1,600	$4,026
Space Heating	Gas Furnace	96%	58.6	$383	$1,903	$4,788
Space Heating	Heat Pump	300%	24.7	$717	$2,224	$4,158
Baseload	Gas Furnace	73%	16.4	$203	-	-
Baseload	Heat Pump	178%	6.7	$249	-	-

Table 3 – Summary of assumptions and inputs for commercial conversions

Demand Category	Equipment Type	Efficiency	Annual Site Energy (MMBtu)	Annual Fuel Costs (2018 $)
Space Heating	Gas Furnace	80%	480.0	$2,284
Space Heating	Gas Furnace	96%	400.0	$1,904
Space Heating	Heat Pump	300%	169.7	$4,371
Baseload	Gas Furnace	72%	243.5	$1,308
Baseload	Heat Pump	125%	142.2	$3,987

Cost of New Builds and Conversions by Fuel Type

Table 4 describes this input data for the residential sector. We have divided these costs between the "equipment costs" for the physical equipment, "installation costs" for the labor associated with setting them up, and "energy costs" for the cost of the natural gas or the electricity to operate the equipment and maintain it for one year. The numbers in Table 4 include the heating costs and the baseload costs associated with other activities, such as heating water.

Table 4 – Input costs and assumptions for residential conversions (2018 $)[11]

Type of Equipment	Equipment Costs	Installation Costs	Energy Costs[12]	Total Costs (2021-2040)[13]
Existing Gas	-	-	$663	-
High-Efficiency Gas	$4,788	$1,903	$586	$18,411
Electrification	$4,158	$2,224	$1,041	$27,202
Electrification (older homes)	$7,918[14]	$2,224[15]	$1,041	$30,962

Replacing existing gas equipment at fleet average efficiency with new, high-efficiency gas equipment would save on energy costs but requires the equipment and installation costs in Table 4. All homes in the Columbus MSA, however, must upgrade between 2021 and 2040 because of our 20-year horizon and 20-year assumption of the useful lifespan of the equipment.

When developers build a new home or an existing home needs to replace its equipment, the choice is between high-efficiency gas and electrification. Electrification would have higher energy costs and higher installation costs, though the cost of equipment would be lower for newer homes. For the 32% of older homes built before 1960 requiring additional upgrades, the equipment costs for choosing electrification would also be higher than new gas. With an example new build or conversion in early 2021, the 20-year cost for the new gas customer is $18,411 and the 20-year cost for electrification is either $27,202 for newer homes or $30,962 for older homes.

Differences in the costs for customers over the age of the equipment – between $8,800 and $12,500 depending if an electric panel upgrade is required – would be a force behind the economic impact of

[11] Assumptions regarding installation costs for natural gas and electric air-sourced heat pump systems imported from, "Implications of Policy-Driven Residential Electrification," *American Gas Association*, 5 September 2018, https://www.aga.org/research/reports/implications-of-policy-driven-residential-electrification/
[12] Includes the annual and ongoing costs of both energy and maintenance
[13] Equipment costs, plus installation costs, plus energy costs times 20 – representative of a conversation from 2021 only because conversions from subsequent years would have less than 20 years of energy costs
[14] Cost to upgrade the water heater branch circuit and electrical panel to higher amperage
[15] Assumed to be the same as for newer homes

electrifying the home and building stocks. Residential customers would have overall higher utility bills with electrification relative to the Base Case. This forces households to economize their spending on the other fixtures of life, such as retail spending or prepared food. Figure 2 illustrates the size of this effect increases over time as more and more homes come online or convert.

Table 5 summarizes our inputs for commercial buildings. For this sector, we have assumed equipment and installation costs are the same between new high-efficiency gas and electrification. All differences in costs for this sector would be, therefore, based on energy costs alone. There is no special carveout for older commercial structures to upgrade their electrical panels.

Table 5 – Input costs and assumptions for commercial conversions (2018 $)[16]

Type of Equipment	Energy Costs	Total Costs (2021-2040)
Existing Gas	$3,592	-
High-Efficiency Gas	$3,212	$64,240
Electrification	$8,358	$167,160

As is the case with residential customers, the difference in lifecycle costs for commercial customers in Table 5 would be a driving factor in the impact of electrifying the Columbus MSA. For the average commercial conversion or new build in early 2021, their costs under electrification would be $102,920 than in the Base Case when using high-efficiency gas.

Facing higher utility bills after electrification of their equipment, commercial enterprises would need to economize as much as residential customers. We have modeled this through a mixture of passing those higher costs along to their customers in the Columbus MSA and reducing their output because high costs reduces their competitiveness on national markets.

Additional Total Energy and Peak Load

AGA also provided FTI with data on the increase in electricity load likely under the electrification. This includes an hourly "load shape" for the average customer by type[17] and the average baseload.[18] The

[16] Assumptions regarding installation costs for natural gas and heat pump systems imported from, "Implications of Policy-Driven Residential Electrification," *American Gas Association*, September 2018, https://www.aga.org/research/reports/implications-of-policy-driven-residential-electrification/

[17] Average residential and commercial space heating and general non-space heating load derived from monthly natural gas consumption data and the Ohio customer count for 2018, "Natural Gas Consumption," *U.S. Energy Information Administration*, https://www.eia.gov/naturalgas/data.php#consumption

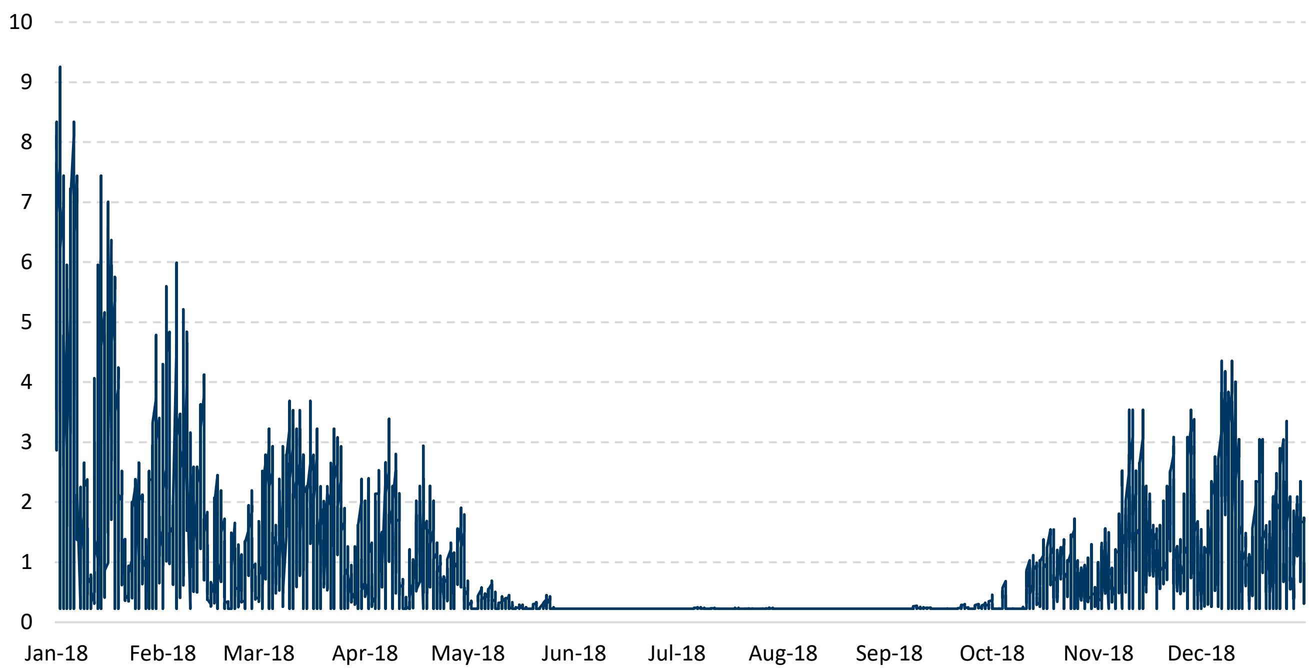
[18] Monthly non-space heating demand determined as the average consumption per Ohio customer in the months of July and August using the Residential Energy Consumption Survey, and an average natural gas customer profile created to convert that demand into general load, "Residential Energy Consumption Survey 2015," *U.S. Energy Information Administration*, https://www.eia.gov/consumption/residential/index.php and, "Commercial Buildings Energy Consumption Survey 2012," *U.S. Energy Information Administration*, https://www.eia.gov/consumption/commercial/

baseload occurs across all hours of the year while the hourly shape represents the hourly and seasonal variations in energy demand for heating and other requirements. AGA analyzed weather data from 2018[19] and a heating degree days methodology to determine the shape.[20]

Our input baseload for the average residential customer was 1,974 kilowatt-hours ("kWh") per year, or 0.23 kWh in any given hour. For the average commercial customer, our input for their annual baseline was 41,709 kWh, or 4.76 kWh of baseload for any given hour of the year. The analysis here does not address the potential for electrification in the industrial sector.

Figure 4 shows the load shape for the average residential customer from the AGA data. The shape implies the load from electrified homes would be at their lowest during the summer months of June, July, August, and into September, which have little heating load.

Figure 4 – Hourly load shape for the average residential customer (kWh)



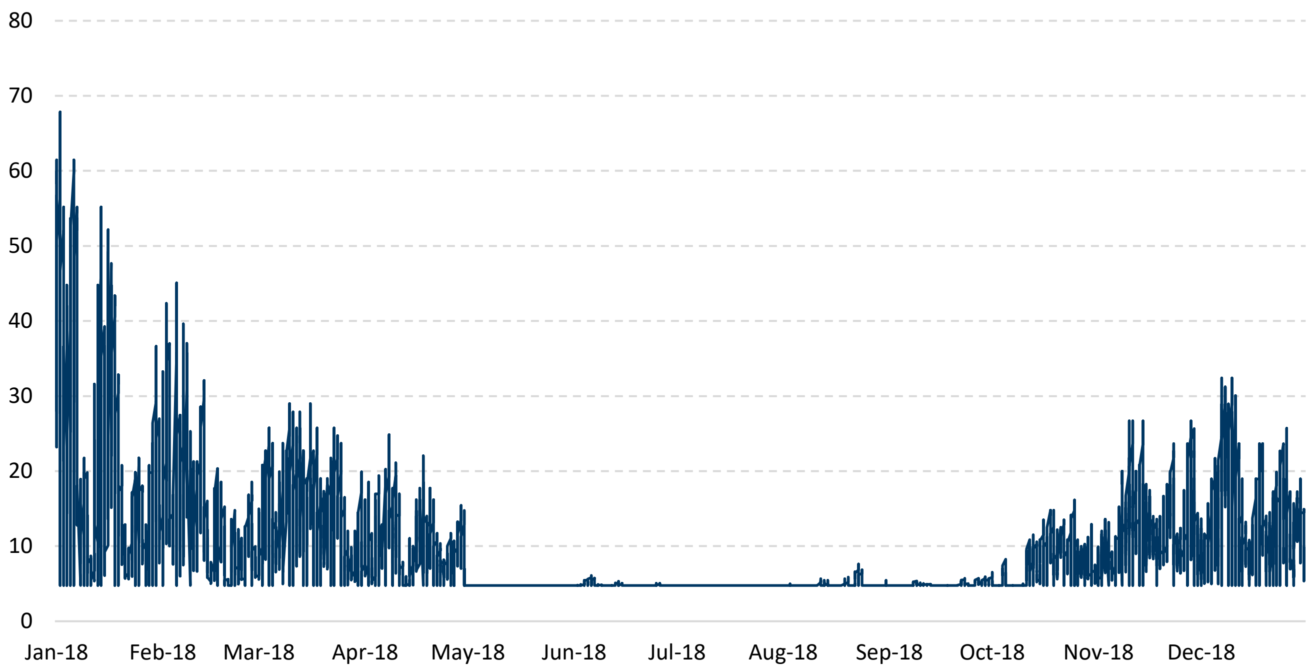
The load for heating begins to appear in October and November, peaks in January, and decreases throughout the rest of the late winter and early spring with numerous oscillations along the way to account for daily and weekly temperature variations in Ohio.

Figure 5 has the same data for commercial customers. The trends between Figure 4 and Figure 5 are generally similar. Summer load from electrified commercial customers is at its nadir, and it is usually the same as the baseload. Heating load becomes a factor in October and November, again peaks in

[19] Monthly space heating load weighted by local hourly weather data from the National Centers for Environmental Information ("NOAA"), https://www.ncdc.noaa.gov
[20] FTI added 7% to the AGA data to account for transmission and distribution losses

January, and slowly decays throughout the first half of the year to May. Despite the straightforward seasonal patterns of the additional load, there are complex and seemingly random fluctuations for hourly and daily load data because of varying temperatures.

Figure 5 – Hourly load shape for the average commercial customer (kWh)



Appendix B summarizes the average electricity load by month and hour for the two customer types. Table 11 covers residential customers, and Table 12 covers commercial customers.

FTI used the load shapes in Figure 4 and Figure 5 as well as the conversions and new builds detailed in Figure 2 and Figure 3 to estimate the additional load on an hourly basis from the start of 2021 through to the end of 2040. First, for any given years, FTI multiplied the load shapes by the sum of all previous conversions and new builds from previous years. Second, we added to that with new conversions and new builds from the present year while assuming the present year's load came online throughout the year linearly (i.e., without season trends). Third, we added this incremental load to the electrification scenarios on top of the preexisting load for AEP in the PLEXOS model.[21]

Building Inputs to the IMPLAN Model

We used the information from the previous subsections to build inputs into the IMPLAN model to simulate the economic impacts of electrification on the Columbus MSA. The inputs represent the net

[21] The heat pumps have a theoretical coefficient of performance of 3.0 and a space heating operating range between 65°F and -27°F. The optimal breaking point was assumed to be 35°F, which would suggest each unit was properly sized to fit the *ASHRAE Handbook* description for heat pump installation, *2016 ASHRAE Handbook, HVAC Systems and Equipment*, Chapter 49, p. 10, Figure 13, "Operating Characteristics of Single-State Unmodulated Heat Pump"

difference between the Base Case and the electrification scenarios. We simulated the results on an annual basis starting in 2021 and concluding at the end of 2040.

Residential Customers

For residential customers, our inputs into IMPLAN take the form of six categories. Those categories include those from Table 4 as well as some additional details:

1. Equipment Spending
2. Installation Spending
3. Maintenance Spending
4. Natural Gas Spending
5. Electricity Spending
6. Consumption Reallocation

"Consumption reallocation" is the money available to residential consumers that they could spend on their own preferences in one scenario but cannot in another because of higher costs. Table 4 shows the electrification of homes would require residential customers to spend more of their incomes on energy-related bills (including #1 through #5 on the list) compared to the Base Case with its lower overall costs. The difference is the consumption reallocation.

Because of the consumption reallocation, households would reallocate their spending away from daily needs for goods and services at the margin. Instead, they would use that same money to cover higher energy-related costs. Such an approach assumes consumers' price elasticity of demand for energy needs is perfectly inelastic. One of the main economic impacts of electrifying the Columbus MSA is the effect that this reallocation has on the economic sectors depending on consumers in the region, such as retail, healthcare, food services, and arts and entertainment.

The following list summarizes how FTI inputted each of these as inputs into IMPLAN:

1. **Equipment Spending** – We inputted net changes in equipment spending by year as added or reduced demand for the relevant manufacturing sectors for gas-fired heating equipment, for electric heat pumps, and for electrical panels. We assumed retrofitting homes would pay for the difference in costs in the immediate year. For new homes, we assumed the difference in costs become part of the purchase price of the home. Hence, we amortized any difference in costs across 30 years of payments. We estimated the interest rate attached to 30-year fixed mortgages in the future based on data from the Congressional Budget Office ("CBO")[22] and from the Federal Reserve. CBO projects the interest rate for 10-year U.S. Treasury Notes from

[22] "The Budget and Economic Outlook: 2020 to 2030," *Congressional Budget Office*, 28 January 2020, https://www.cbo.gov/publication/56020

2021 through 2030,[23] which we extended by assuming the rate for 2030 (3.1%) remains the rate through 2040. We then analyzed the historical difference between interest rates on 10-year U.S. Treasury Notes[24] and 30-year fixed mortgages.[25] We found the difference between the two was 1.76% on average over the past 20 years. We applied this difference to the extended CBO forecast to generate a forecast of mortgage rates out through 2040.

2. **Installation Spending** – We inputted net changes in installation spending by year through demand for the relevant construction and maintenance sectors in IMPLAN. We applied similar assumptions to these inputs as the ones for equipment spending – installation costs for new homes become part of the purchase price, and the costs are part of amortizing the price of the structure. Retrofits are considered a cost in the immediate year.
3. **Maintenance Spending[26]** – For maintenance, we entered net changes in spending by year by changing demand for the relevant construction and maintenance sectors in IMPLAN. We assumed maintenance spending is a cost in its immediate year.
4. **Natural Gas Spending** – We entered the net changes in natural gas spending – which was a reduction when moving from the Base Case to the electrification scenarios – as a decrease in demand for the natural gas distribution sector in IMPLAN. The gas distribution sector in IMPLAN includes local gas utilities and, through the input-output linkages inherent within the model, it links into natural gas pipelines and extraction.
5. **Electricity Spending** – We entered the net changes in electricity spending as a decrease in the demand for the electric power transmission and distribution sector in IMPLAN. Such spending increased in the electrification scenarios relative to the Base Case, and we considered energy expenditures as something covered in their immediate year.
6. **Consumption Reallocation** – For any given year, we entered the opposite number as the sum of the other five factors as consumption reallocation. For instance, if for each year the net effect regarding the sum of the costs for the other five factors was $2,000, then we reallocated the level of household consumption by -$2,000 in IMPLAN. We used the underlying consumption equation in IMPLAN to determine which economic sectors would experience a decrease in their demand through the apportionment of the consumption reallocation.

Figure 6 provides an example of the IMPLAN inputs for the residential sector in 2040. Spending for equipment would be slightly higher ($4 million) in the Base Case, though higher expenditures for

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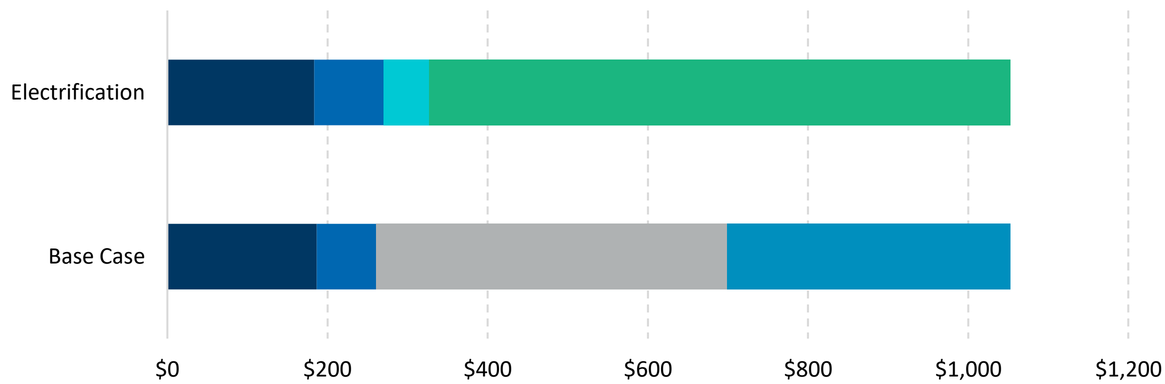
[23] "10-Year Economic Projections," *Congressional Budget Office*, 28 January 2020, https://www.cbo.gov/system/files/2020-01/51135-2020-01-economicprojections_0.xlsx
[24] "10-Year Treasury Constant Maturity Rate," *Federal Reserve Economic Data*, https://fred.stlouisfed.org/series/DGS10
[25] "30-Year Fixed Rate Mortgage," *Federal Reserve Economic Data*, https://fred.stlouisfed.org/series/DGS10
[26] Considered separately here and in the inputs to the IMPLAN model even if combined with the ongoing expenditures for energy/operations in Table 4

installation and maintenance in the electrification scenarios mean cost for equipment and labor would be higher ($66 million) in that scenario. The lion's share of the difference in costs between the situations comes from energy costs. In the Base Case, the residential sector spends $439 million on natural gas compared to $726 million when under electrification.

The difference in total expenditures between the two – which is $354 million – becomes the data for the consumption reallocation in Figure 6. Household consumers in the Base Case would have more leftover income to spend on their typical needs and wants.

Figure 6 – IMPLAN inputs for 2040 for the residential sector (2018 $ millions)



	Base Case	Electrification
Equipment Spending	$187	$183
Installation Spending	$74	$87
Maintenance Spending	$0	$57
Natural Gas Spending	$439	$0
Electricity Spending	$0	$726
Consumption Reallocation	$354	$0

Commercial Customers

The process for building IMPLAN inputs related to commercial customers was like the approach for residential customers. However, there were two important differences:

1. We assumed equipment costs, installation costs, and maintenance costs were the same for commercial customers between the Base Case and the electrification scenarios (as we earlier described in Table 5). Hence, there was no need to consider if commercial customers would amortize their costs over a 30-year loan period, and we assumed they covered their higher costs for electricity relative to natural gas in the immediate year.
2. FTI treated the equivalent concept to "consumption reallocation" for commercial customers differently than we did for residential customers, which we document here.

Under the electrification scenarios, commercial customers would have higher energy costs than they would under the Base Case. We need to reflect these higher costs in the IMPLAN model, though commercial customers are not like households where they would simply reduce their consumption on the margin like households would when paying higher utility bills.

We have modeled this reallocation in IMPLAN through two paths. For the share of each commercial sector's business done within the Columbus MSA,[27] we have assumed they pass the same proportion of their higher costs along to customers within the Columbus MSA. For instance, IMPLAN estimates 76.4% of hospital activities[28] in the Columbus MSA are for consumers in the Columbus MSA with the remainder (24%) "exported" to customers outside the Columbus MSA.

We consider the 76.4% estimate from IMPLAN reasonable for three reasons. First, it is lower than the other healthcare sectors (such as ambulatory care). Other healthcare sectors in the Columbus MSA derive more than 95% of their business from the Columbus MSA, which is sensible when patients in need of ambulatory services are more likely to seek services close to home. Second, the 76.4% figure is much higher than sectors that purely depend on exports. For instance, sectors such as hotels generate less than 5% of their business from local customers in IMPLAN.

Our third reason is the most notable and requires additional context. The Columbus MSA has a large healthcare sector that services not just local customers but also the surrounding rural areas, the rest of Ohio, and even other states. Example institutions include the Ohio State University's Wexner Medical Center,[29] OhioHealth, Mount Carmel Health System,[30] and Nationwide Children's Hospital. Each of these institutions employs thousands and has multiple facilities. All rank among the largest employers in the Columbus MSA along with the state of Ohio.[31] Thus, IMPLAN illustrating the economy and the healthcare system of the Columbus MSA as "most" (76.4%) of inpatients are from the Columbus MSA with 24% of inpatients from the surrounding region is reasonable.

For the share of higher energy costs attributed to exports, we have reduced the direct outputs of commercial sectors themselves. Higher costs for businesses in the Columbus MSA would degrade their competitiveness relative to the other options in the regions for consumers. For instance, to continue with the example of hospitals, their higher energy costs to provide inpatient care would discourage patients and insurance companies from the regions outside of the Columbus MSA from using their services. Instead, nonlocal patients could instead choose to utilize local facilities or similarly renowned facilities in Cincinnati, Cleveland, Pittsburgh, or southeast Michigan.

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[27] IMPLAN calls this the "local use ratio" or the "regional supply coefficient," the "RSC"

[28] NAICS 622, "Industries in the Hospitals subsector provide medical, diagnostic, and treatment services that include physician, nursing, and other health services to inpatients and the specialized accommodation services required by inpatients, https://www.census.gov/cgi-bin/sssd/naics/naicsrch?code=622&search=2017%20NAICS%20Search

[29] "About Us," *The Ohio State University Wexner Medical Center*, https://wexnermedical.osu.edu/about-us

[30] "About Us," *Mount Carmel*, https://www.mountcarmelhealth.com/about-us/

[31] Robin Smith, "Here are Central Ohio's largest employers: Our rankings found 120+ organizations with 100+ workers," *Columbus Business First*, 12 July 2019, https://www.bizjournals.com/columbus/news/2019/07/12/here-are-central-ohios-largest-employers-our.html

Figure 7 shows an example flowchart of this process for the hospital sector. The process is similar in all other commercial sectors within the IMPLAN model.[32]

Figure 7 – Calculation process in 2040 for the hospital sector

1. **Increase in energy costs for all commercial customers** = $326.3 million
2. **Hospitals' share of all commercial customers' natural gas demand in IMPLAN** = 3.2%
3. **Increase in hospitals' energy costs in 2040** = $10.5 million[33]
4. **Share of hospitals' customers coming from the Columbus MSA** = 76.4%
5. **Higher costs passed along to local customers in the Columbus MSA** = $8.0 million
    a. Add these costs to the "consumption reallocation" from the previous section
    b. Similar effects to economic sectors depending on consumer expenditures
6. **Costs borne by hospitals as reduced output from reduced competitiveness** = $2.5 million

We repeated a similar set of calculations for all commercial sectors in the IMPLAN model for all years, which we then inputted into the model for our simulations.

Electricity Prices

We also modeled the impacts of higher electricity prices in IMPLAN. As described, the electrification scenarios would engender additional electricity load in PJM and AEP specifically. For both the MB Scenario and the RO Scenario, two important results of this would be higher average annual prices for electricity and more pronounced seasonality between summer and winter.

To calculate the increase in the "bill"[34] between the Base Case and electrification scenarios for all customers in the Columbus MSA,[35] we first multiplied the underlying load from the Base Case in PLEXOS for AEP by the percent increase in electricity prices for the RO Scenario. To capture the seasonality in prices, we calculated this difference on a monthly basis.

After consultation with AGA, we simulated the economic impact of electrifying the Columbus MSA under the RO Scenario. AGA felt that electrification paired with the requirement that new capacity additions to service that load must be renewables was a more realistic and relevant representation of potential policy designs related to electrifying the regional building stock.

The AEP zone includes most of the Columbus MSA but also much of Ohio and parts of other states. These include southeastern Ohio, the region of Ohio between Dayton and Toledo, much of northwest

[32] In NAICS order, starting with wholesale trade and ending with services to private households
[33] Assumed gas demand in IMPLAN by sector was a superior factor for apportionment than electricity demand by sector because the situations examine converting from natural gas to electricity
[34] Consumption times prices
[35] Including industrial customers

Indiana and southeast Michigan, some of the West Virginia panhandle and the southwest of the state, eastern Kentucky, and stretches of southern and western Virginia.[36]

We calculated the Columbus MSA's share of AEP load by calculating the average per capita electricity consumption in Ohio.[37] Using this methodology and the population of the Columbus MSA, we found that the Columbus MSA accounted for roughly 20% of the load for the AEP zone. While some outer suburbs of Columbus are outside of AEP's service territory, they are either (1.) still part of the AEP zone, such as if serviced by a cooperative, or (2.) part of PJM even if in another zone inside of the PJM system. For simplicity, we have illustrated the whole MSA as in AEP.

We multiplied the change in the bill between the Base Case and the electrification scenarios by 20% to specify the bill change for the Columbus MSA (as opposed to the grand total for the AEP zone). We allocated this total by year between residential, commercial, and industrial customers based on their share of retail electricity demand in Ohio from EIA data.

For residential customers, we applied the same approach with consumption reallocation that we did with their higher costs for switching from natural gas to electricity for their heating and appliance needs. As before, the higher residential bill implies higher utility bills for existing electricity demand (such as for their air conditioners, electronics, or lighting). When residential customers face higher utility bills at the end of the month, they trim consumption elsewhere.

For commercial and industrial customers, we applied a similar approach to the one with commercial customers converting from natural gas to electricity. The share of their business with local customers is the share of their costs passed through to local consumers. The remainder becomes a reduction in their direct output to illustrate a reduction in competitiveness. Unlike the approach with commercial customers, this applies to industrial customers, as well, because their preexisting load would have to experience higher prices even if they are not electrifying their processes.

Because we used a bill methodology based on wholesale prices only, we are assuming distribution costs – the markup electricity utilities charge to cover their costs to bring electricity from wholesale markets to local distribution – would remain unchanged.

We also increased the energy costs from Table 4 and Table 5 for homes and commercial structures electrifying over time. Electrified residential customers would pay $966 in 2021 for energy, which would increase to $971 in 2040.[38] For electrified commercial customers, the same figures would rise from $8,359 in 2021 to $8,407 in 2040 (or a change of 0.6%). These higher costs for the customers in the Columbus MSA would become an important factor in IMPLAN.

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[36] "PJM releases 2018 load forecast," *PJM*, 28 December 2017, https://insidelines.pjm.com/wp-content/uploads/2016/01/2015-Load_Report_Cover.png
[37] "Ohio," *U.S. Energy Information Administration*, https://www.eia.gov/state/?sid=OH
[38] 2018 dollars

Simulation Results

We have organized the results of the simulations in PLEXOS and IMPLAN into two sections. The first section describes the power market simulations in PLEXOS for the MB Scenario, the RO Scenario, and the important distinctions between the two. The economic impact results from IMPLAN are from the RO Scenario only and include the fiscal impacts of electrification, as well.

Power Market Results

Results for the power market modeling divide into several subsections. These include those for the incremental load added by the electrification scenarios, the impact on capacity expansion and on the price of electricity in the AEP zone, and emissions throughout PJM.

Electricity Load

Figure 8 shows the additional load required in the AEP zone because of the electrification scenarios. Impacts increase over time as more and more structures electrify per Figure 2 and Figure 3. By 2040, the impact is around 11.7 million megawatt-hours ("MWh"). Compared to the underlying load for existing customers, this is around a 7.8% increase in the total energy.

Figure 8 – Annual AEP zone total energy

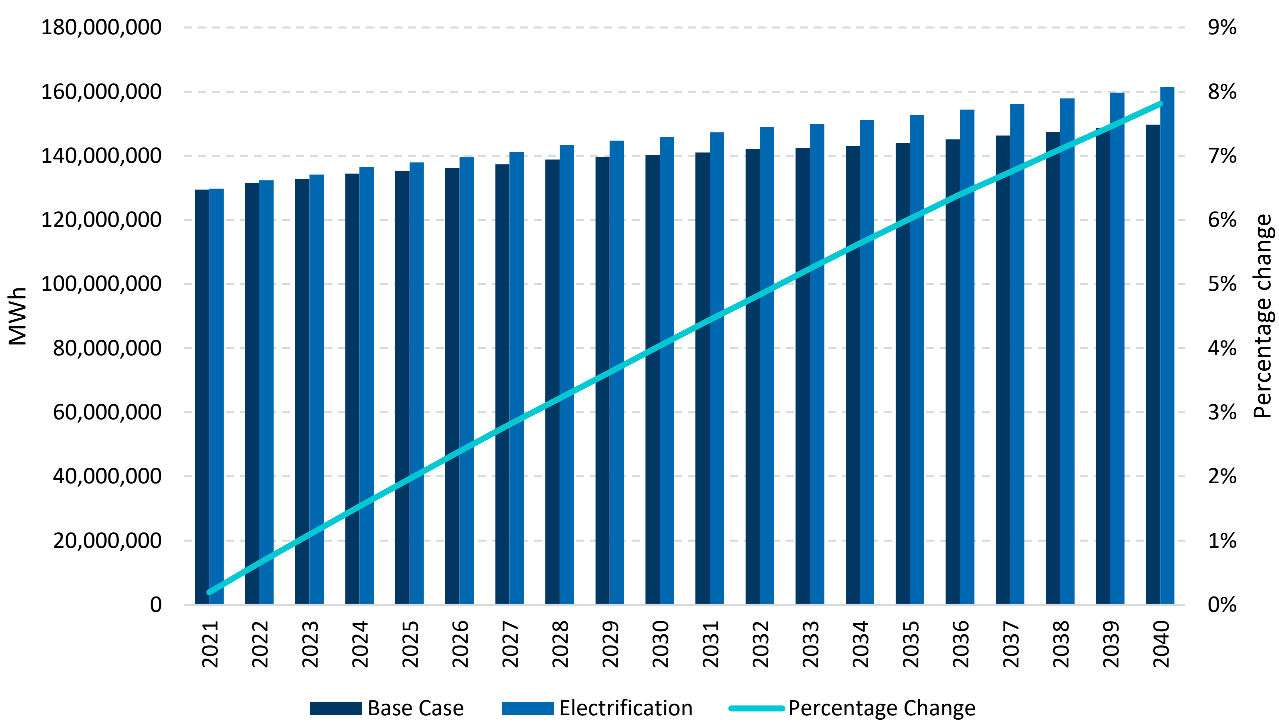


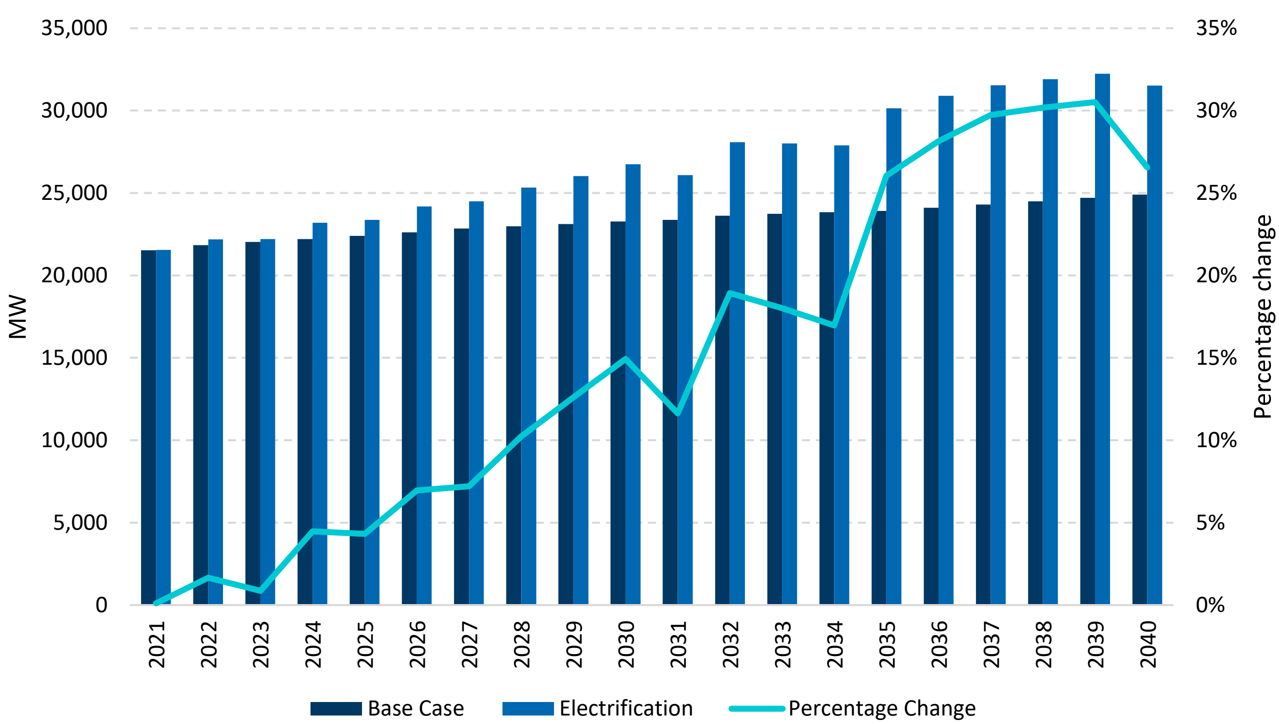
Figure 9 relies on the same underlying dataset as Figure 8 but looks at the peak load for the AEP zone. Total energy would increase in a dependable fashion year-by-year as structures electrify. On the other hand, peak load would be more complex because heating demand for the Columbus MSA would not necessarily be coincident with the peak load for the rest of the AEP zone.

We used the same load shape (from AGA) for all years to estimate the hourly peak heating demand. According to both Figure 4 and Figure 5, this would be at 7:00 AM and 8:00 AM on January 2. The load shape for the existing load in PLEXOS is more dynamic and realistic. Based on its own 2018 load shape, PLEXOS varies the peak hour for the preexisting load throughout late January and early February on different days each year though typically at 7:00 AM or 8:00 AM.

Upon adding the electrification load to the preexisting load, we should expect their peaks to occur in different hours. The Columbus MSA is around 20% of the load for the AEP zone, which stretches from east of the Appalachian Mountains in Virginia to the shores of Lake Michigan. Weather conditions for the same hour can vary across such a large area,[39] so we should imagine the long-term trend from electrifying the Columbus MSA to increase peak load for the zone but not for the trend to be steady or constant because of hourly weather variations between the years.

Figure 9 and its data reflects the logic of this construction. Peak load in 2040 absent electrification is 24,900 megawatts ("MW"). With the electrification load added, it is 26.5% higher at 31,500 MW. Conversely, because of the realistic year-by-year variations in our load inputs to PLEXOS, this is less compared to 2039 when the impact to peak load would instead be 30.5%. The trend over 20 years is nonetheless upwards as more structures undergo their conversions.

Figure 9 – Annual AEP zone peak load



[39] For example, Benton Harbor, Michigan to Danville, Virginia (at the extreme ends of the zone to the northwest and the southeast, respectively) would require a 12-hour drive of approximately 700 miles

Figure 10 shows the same data as Figure 8 only on a monthly basis. It delineates between months of relatively high load compared to months of comparatively low load. In the earliest years of Figure 10 for both the Baseline Simulation and the electrification scenarios, the AEP zone has peak months in the midwinter and the midsummer with shoulder months in the spring and fall. With the electrification scenarios, this situation changes over time. Summer months, such as June, July, and August, would become secondary peaks compared to January and February.

Figure 10 – Monthly AEP zone total energy

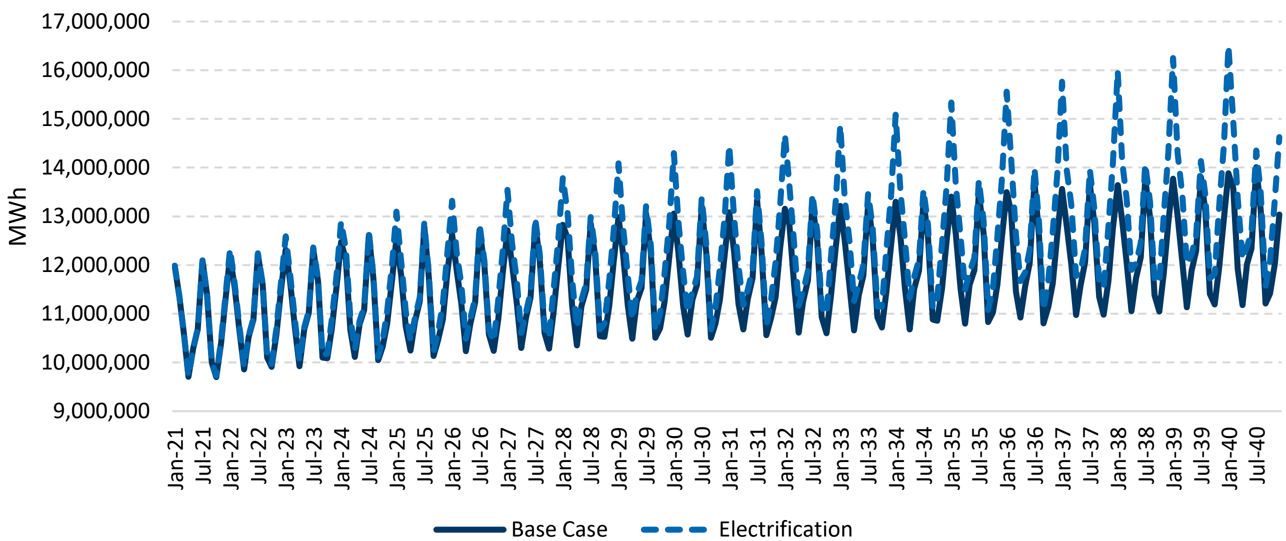
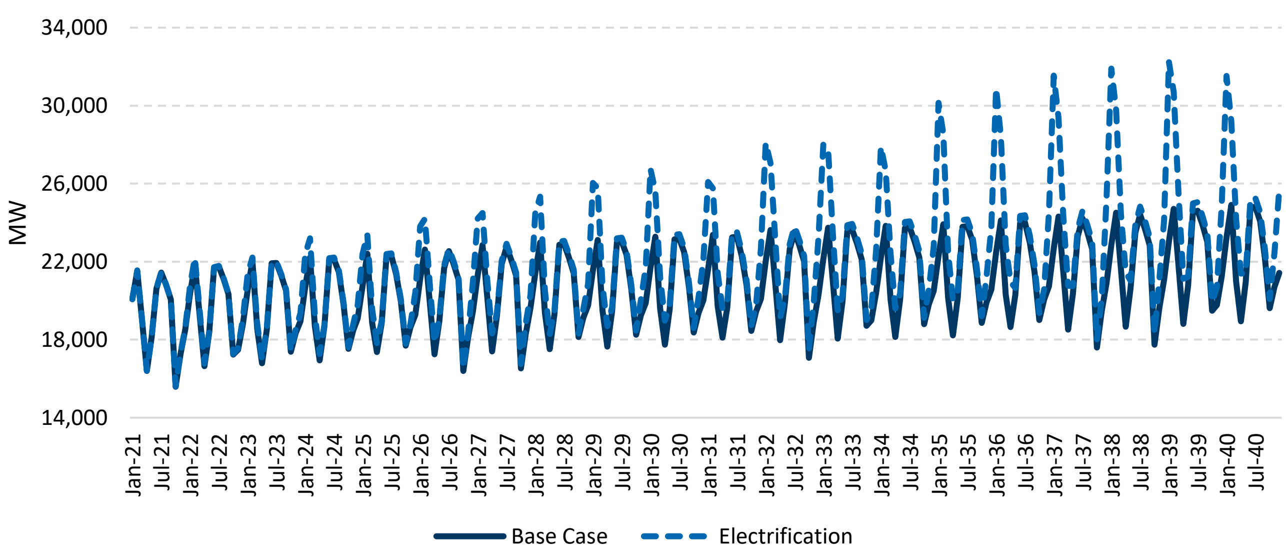


Figure 18 has similar seasonal patterns. In the Base Case, peak summer load and peak winter load were close to each other. Over time, the electrification scenarios would increase peak winter load higher and higher in comparison to the peak load experienced during the summer months.

Figure 11 – Monthly AEP zone peak load



Capacity Expansion

We simulated the impacts of the additional load from Figure 8 through Figure 11 in PLEXOS without other changes (e.g., natural gas prices or renewable portfolio standards). PLEXOS makes capacity additions to the power market based on the economics of potential additions and the need for the electricity system to maintain appropriate planning reserve margins.[40]

Table 6 summarizes the capacity expansion results for the Base Case and the two scenarios under the electrification from 2021 through 2040.[41] The bottom rows summarize the difference of additions between the electrification scenarios and the Base Case. For more detailed, year-by-year results of the simulations, please see the tables included in Appendix C.

Table 6 – Capacity expansion from PLEXOS simulations for PJM (2021 to 2040, gigawatts)[42]

Scenario	Solar	Wind	Biomass	Natural Gas (Combined Cycle)[43]	Thermal Retirements[44]	Net Additions
Base Case	49.9	4.1	0.2	14.6	2.6	66.2
MB Scenario	49.9	4.1	0.2	15.8	2.6	67.4
RO Scenario	51.9	3.9	0.2	14.6	2.6	68.1
MB Scenario versus Base Case	0.0	0.0	0.0	1.2	0.0	1.2
RO Scenario versus Base Case	2.0	-0.1	0.0	0.0	0.0	1.9

Table 6 reveals several important trends driving the results for electricity prices and emissions under the different setups. Across PJM and between 2021 and 2040, the Base Case would add 51.9 GW of

[40] The planning reserve margin measures the amount of generating capacity available to meet expected demand, and an adequate planning reserve margin ensures the system can meet instances of high and peak load
[41] There would be no additions of other generation types in the simulations, such as nuclear plants
[42] Numbers may not add exactly due to rounding
[43] Natural gas additions all used combined cycle technology – there were no "peaker" unit additions
[44] Includes coal and older natural gas-fired units

solar capacity, 3.9 GW of wind capacity, 0.2 GW of biomass, and 14.6 GW of natural gas plants using combined cycle technology. There would also be 2.6 GW of retirements from coal and older gas plants, bringing total net capacity additions over 20 years to 66.2 GW.

Under the MB Scenario, these changes would mostly be the same except for NGCC plants. Because of the additional load throughout the year from Figure 8 and Figure 10 and the peak load from Figure 9 and Figure 11, PJM would add 1.2 GW of NGCC plants. This is less than the increase in peak load from Figure 9 and Figure 11, which in 2039 would be roughly 7.5 GW. The NGCC additions would be less than the increase in peak load from the Columbus MSA for two reasons.

Firstly, the incremental additions to peak load would not necessarily be coincident with peak load across the whole of the PJM system. AEP is one of the largest zones in PJM by land area, but PJM stretches from Illinois, to North Carolina, to New Jersey. It encompasses portions of the Midwest, Appalachia, and the Mid-Atlantic regions. In most instances, its sizeable footprint would give PJM ample "slack" capacity to meet peak heating demand in the Columbus MSA. Secondly, PLEXOS allows for imports from other systems, such as the Midcontinent Independent System Operator ("MISO"),[45] which gives AEP and PJM another avenue for satiating peak load.

Nevertheless, additional load in the electrification scenarios would engender conditions suitable for adding the 1.2 GW of NGCC plants from the MB Scenario. New NGCC plants like the 1.2 GW would be competitive on the market – new NGCC plants have low heat rates and dispatch at lower costs than existing thermal units, and they would also be a flexible resource. This pair of factors would help contribute to any new NGCC plants running at a high capacity factor.

In the RO Scenario, the results would be largely alike to the MB Scenario save for incremental builds of solar plants and NGCC plants. Instead of 1.2 GW of NGCC plants, the RO Scenario would add 2.0 GW of solar capacity. There would also be a small (145 MW) reduction in the wind builds, though the key contrast between the MB and RO Scenarios would be with solar and gas.

Appendix C has specific year-by-year additions by plant and simulation. The consideration to note with the year-by-year additions is they would be "stepwise" or "lumpy" over time. That is, future power plants would not come online in a smooth, linear fashion. They would instead come online when reserve margins require them or market economics are favorable, such as a new NGCC plant typically having a capacity between 350 MW and 850 MW.[46] Such effects would create discontinuities when the incremental plants come online in the electrification scenarios.

Additionally, considering IMPLAN again for a moment, FTI did not attempt to model the economic impact of plant construction or operations on the Columbus MSA. Our results in Table 6 cover the

[45] "About MISO," *Midcontinent Independent System Operator*, https://www.misoenergy.org/about/

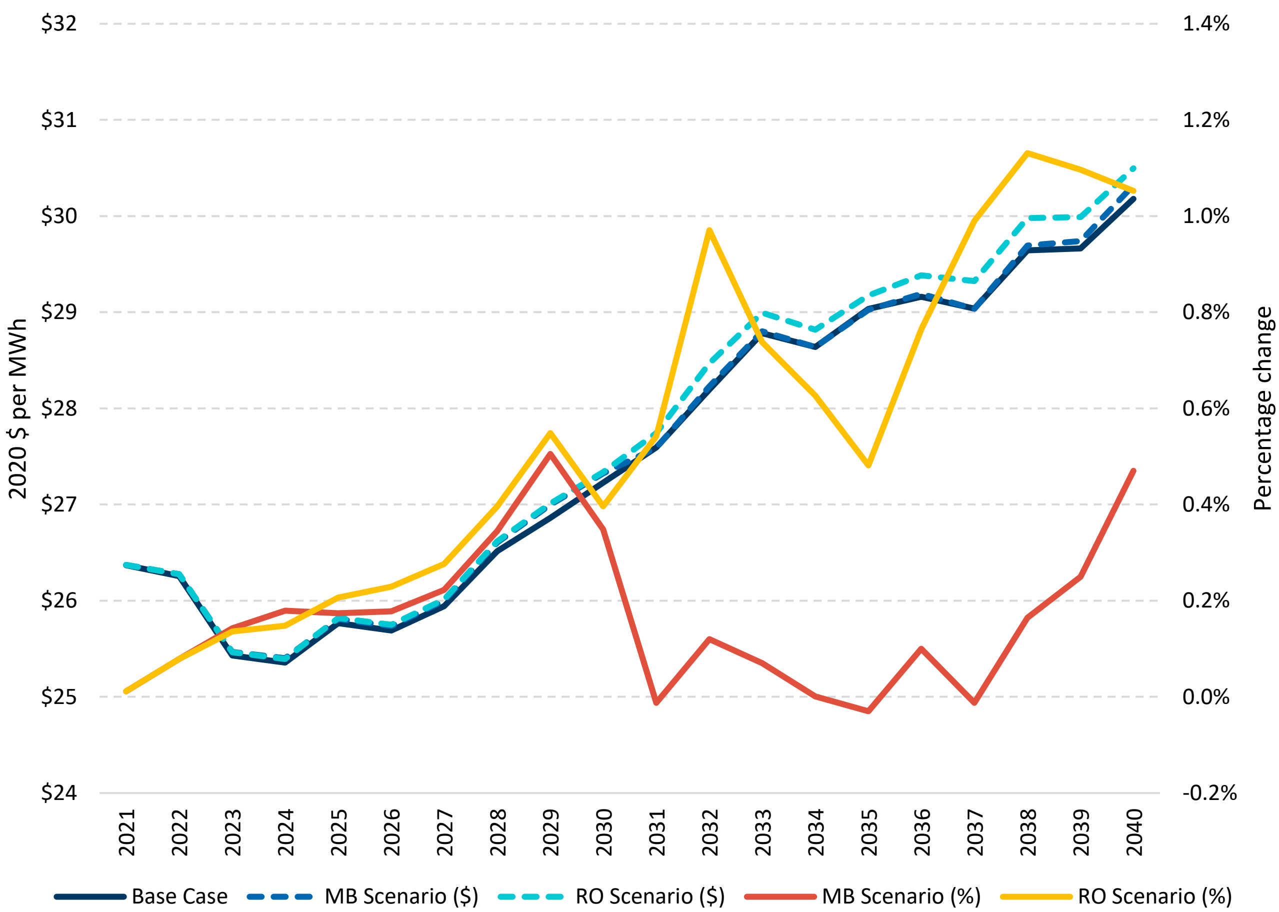
[46] "Power blocks in natural gas-fired combined cycle plants are getting bigger," *U.S. Energy Information Administration*, 12 February 2019, https://www.eia.gov/todayinenergy/detail.php?id=38312

whole of PJM and, even if the 1.2 GW of NGCC in the MB Scenario or the 2.0 GW of solar in the RO Scenario were in AEP, they would be unlikely to be in the Columbus MSA. Utility scale generation is generally in rural areas and away from populated metropolitan areas. Impacts from construction or operations of plants would likely be minimal in the Columbus MSA.

Electricity Prices

Figure 12 shows electricity prices and the impacts to the same across the Base Case and the scenarios for the AEP zone. The three lines for prices – in the varying shades of blue – would stay close to one another across the three simulations, though the MB Scenario would typically have higher prices than the Base Case and the RO Scenario would be higher still than that.

Figure 12 – Annual AEP wholesale electricity price (2018 $)

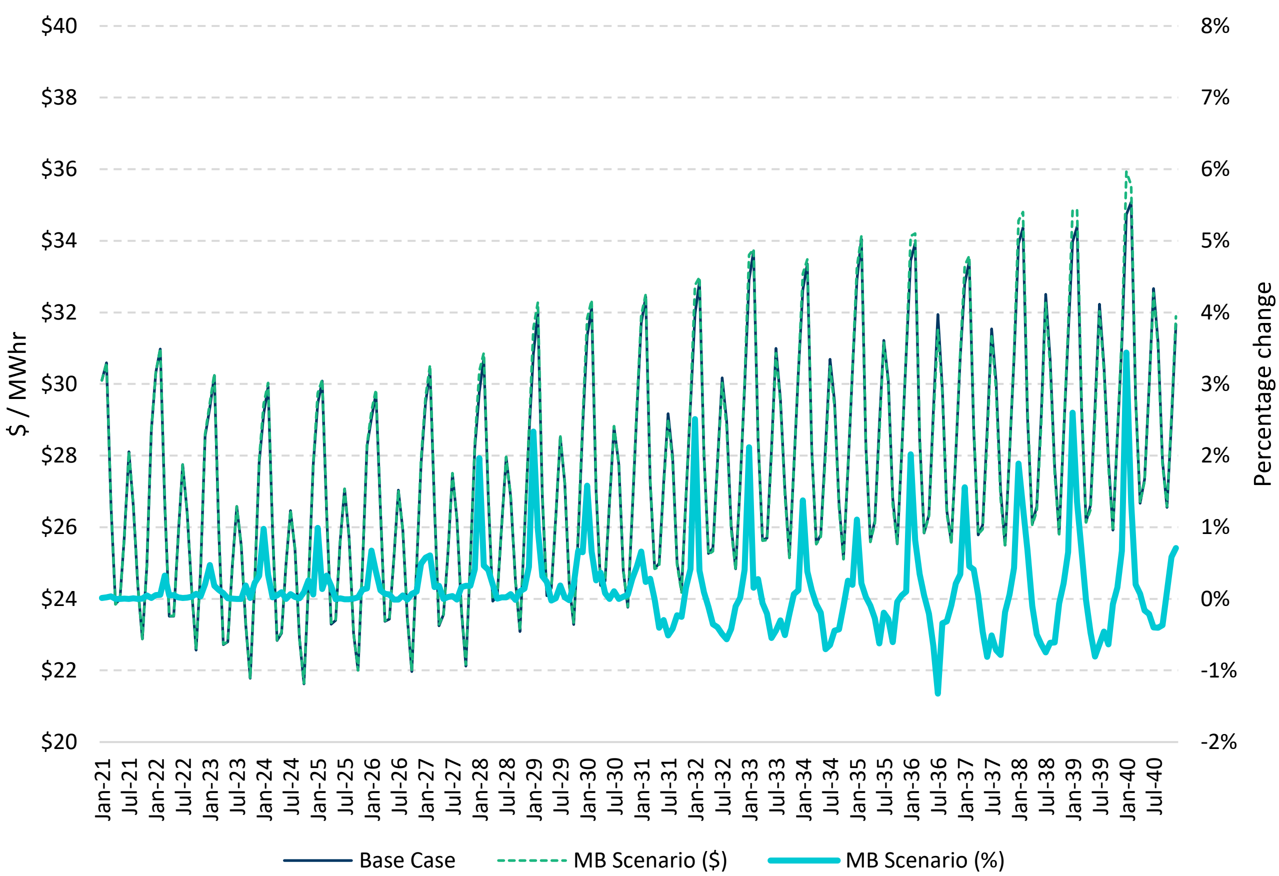


The most important trends in Figure 12 come with the percentage differences. Between 2021 and 2029, there would be little difference in the electricity price impact relative the Base Case with either of the electrification scenarios. The impact in both would peak around 0.5% in 2029. Starting in 2030 and the early 2030s, however, they would diverge. The impact for the MB Scenario would be close to zero until the late 2030s, while the impact for the RO Scenario would be between 0.5% and 1.0% for the remaining years in the 2030s, which is higher than the MB Scenario.

The difference would come down to the preponderance of NGCC or solar additions between the MB and RO Scenarios, respectively, and their influence on electricity markets. The 1.2 GW of NGCC plants within the MB Scenario are lower cost resources to construct and, with their high capacity factors, they would have more of an effect on the market. The 2.0 GW of solar plants within the RO Scenario are higher cost resources to construct and, with their lower capacity factors, they would have less of an impact on the market despite their higher nameplate capacity.

In Figure 13, we show the electricity price for AEP in the Base Case and the MB Scenario. In simple supply-and-demand terms, higher overall load should lead to higher prices. However, because heating load is heavily seasonal, the effect on price would vary throughout the year. For the 2020s, impacts on price would include higher prices in the winter with little effect during the summer and shoulder months. Once 1.2 GW of new NGCC plants begin operating in the 2030s, the increase relative to the Base Case for the winter months would remain yet the price impact for the summer and shoulder months would be one of neutral or even decreasing prices.

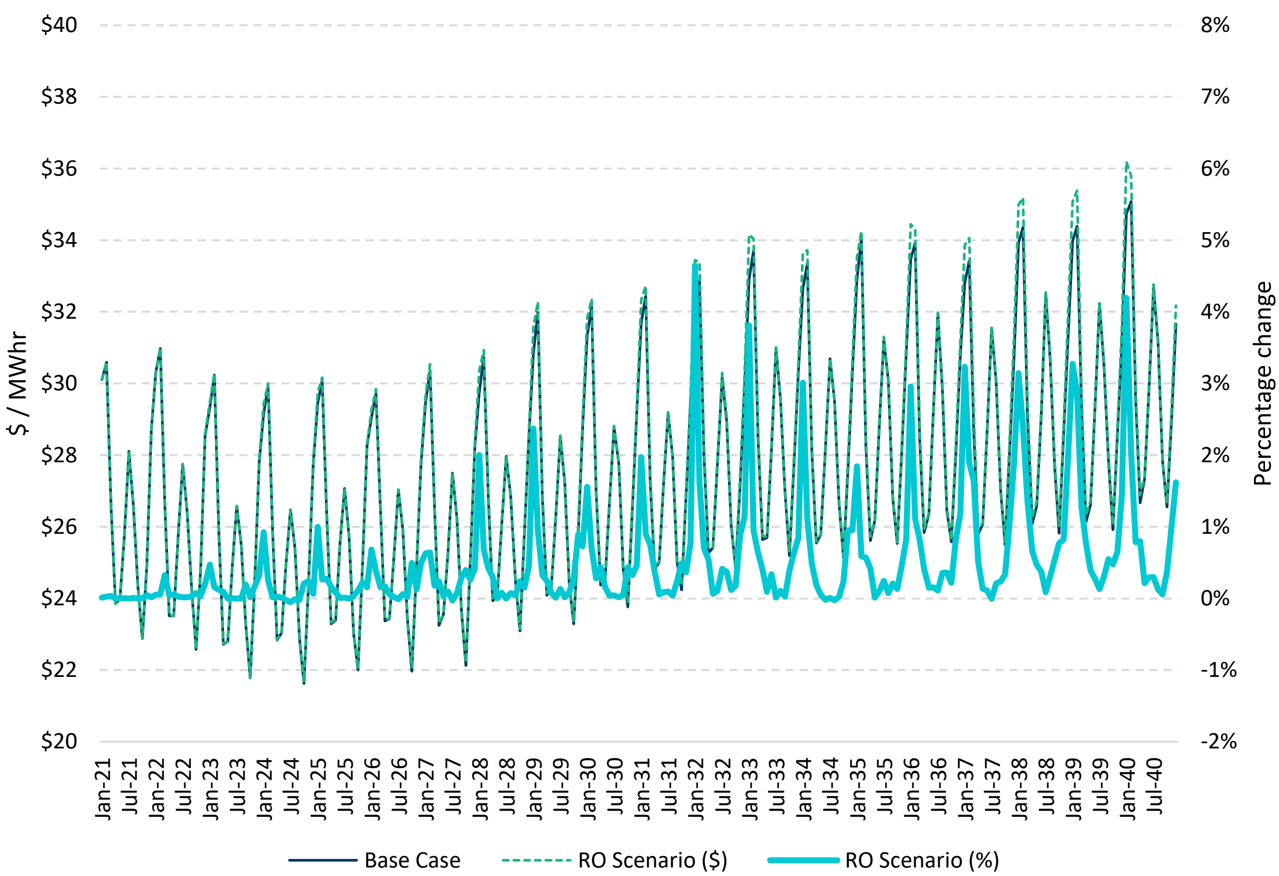
Figure 13 – Monthly AEP wholesale electricity price in the MB Scenario (2018 $)



A price decrease in a scenario involving higher load might seem counterintuitive, yet it follows from understanding the market dynamics. The 1.2 GW of NGCC capacity, built to handle the higher peak load and total energy throughout the year, would not only operate in January to coincide with peak heating load in the Columbus MSA. The plants' low and attractive heat rates would mean they would operate throughout the year and displace other resources with higher costs. Displaced plants would likely be older coal and natural gas units, which the new NGCC units would supplant on the market because they can dispatch at lower prices for electricity.

Figure 14 describes monthly trends in prices for the RO Scenario. In the 2030s, in a similar trend with the MB Scenario, the added heating load would increase prices in the winter while having no strong impact on prices during the summer and shoulder months. Unlike the MB Scenario, this trend would continue in the 2030s instead of the summer and shoulder months having lower prices in scenario compared to the Base Case. As within the MB Scenario, the reason for the higher prices with the RO Scenario involves changing market dynamics with new capacity.

Figure 14 – Monthly AEP wholesale electricity price in the RO Scenario (2018 $)



The RO Scenario adds 2.0 GW of solar power, which would have less of an influence on the market in summer and shoulder months compared to the 1.2 GW of NGCC plants. The solar plants would run at lower capacity factors than the NGCC plants, and the NGCC plants would be able to increase their dispatch quickly when power is most in demand and electricity prices are highest. Their intermittency would constrain the solar plants from having the same impact on the market.

Taken together, the NGCC plants in the MB Scenario would be able to displace more coal and gas than the solar in the RO Scenario, leading to the results in Figure 14.

Emissions Results

The PLEXOS modeling produced results for emissions of CO2, NOx, and SO2. Table 7 includes summary results for 2021 to 2040 for the three different types of emissions across 20 years. Appendices have results on an annual basis. Table 7 includes both the emissions from generators in PJM and emissions from generation outside of PJM yet imported into the system.

Table 7 – Emissions results (2021 to 2040)

Scenario[47]	CO2 (millions of metric tons)	NOx (thousands of short tons)	SO2 (thousands of short tons)
Base Case[48]	52.9[49]	58.2[50]	0.5[51]
MB Scenario	48.3	10.0	5.0
RO Scenario	65.6	31.3	38.4
MB Scenario versus Base Case	-4.6 (-8.7%)	-48.2 (-82.9%)	4.5 (908.2%)
RO Scenario versus Base Case	12.8 (24.2%)	-26.9 (-46.3%)	38.1 (7,657.0%)

Table 7's results vary depending on the electrification scenario and the compound. For CO2, the MB Scenario would reduce emissions compared to the Base Case by 4.6 MMT. The RO Scenario, on the other hand, would increase CO2 emissions by 12.8 MMT. Like with prices, the higher CO2 emissions results for a scenario designed around expanding renewable capacity might seem counterintuitive, though they descend from the earlier discussion on market dynamics.

As discussed earlier, the price impact of the MB Scenario would be less severe because NGCC plants would be more effective at displacing coal and older gas plants than the solar added under the RO Scenario. Despite the new NGCC plants emitting when they generate, the quantity of coal that they

[47] Emissions results for the MB Scenario and RO Scenario are outputs of the PLEXOS model
[48] For homes converted to high-efficiency natural gas, we modeled each home requiring 77.7 million cubic feet ("Mcf") of gas each year; for commercial structures, we modeled their gas demand as 666.7 Mcf per year
[49] 117.1 pounds of CO2 per Mcf of natural gas
[50] 0.117 pounds of NOx per Mcf of natural gas
[51] 0.001 pounds of SO2 per Mcf of natural gas

would displace would overcome the solar plants' advantage of zero direct emissions. The stronger displacement of coal under the MB Scenario is evident in the NOx and SO2 results from Table 7 with the MB Scenario having less NOx and SO2 compared to the RO Scenario.

For NOx and SO2, the results in Table 7 depend on the compound. The Base Case would have higher NOx emissions compared to either scenario, though both scenarios would have higher SO2 emissions compared to the Base Case. With a different "story" for each of the compounds across the various simulations, analyzing the "efficiency" of electrifying energy demand from residential and commercial customers in reducing emissions depends on a handful of factors. Those factors include the costs for achieving those reductions and a reasonable valuation for the same.

Table 8 undertakes this valuation using social costs. The social costs under the calculations are $50.86 per metric ton for CO2;[52] $6,704 per short ton for NOx, and $39,599 per short ton for SO2. The table includes the difference in the valuations between the electrification scenarios and the Base Case for each individual compound as a sum of the totals in the rightmost column.

Table 8 – Valuation of the increased or decreased emissions in the scenarios (2018 $ millions)

Scenario	CO2	NOx	SO2	Total
MB Scenario versus Base Case	$233.1	$323.4	-$179.0	$377.5
RO Scenario versus Base Case	-$649.5	$180.7	-$1,508.8	-$1,977.6

The RO Scenario would have lower NOx emissions than the Base Case, but it would be counter to the purpose of reducing CO2 emissions or improving air quality given results for SO2 emissions in Table 7 and Table 8. The MB Scenario presents the more interesting argument, though its reduction in CO2 and NOx emissions relative to the Base Case comes only at enormous cost.

Extending Figure 6 out to all years and customer types would mean the Columbus MSA's customers face $7.4 billion in additional costs from electrification. That figure includes only the Columbus MSA and none of the costs borne by customers paying slightly higher prices for electricity throughout the geographical footprint of PJM. Consequently, for CO2 alone, the costs for emissions reductions would be $1,615 per metric ton. If including NOx and SO2 in a benefit-cost using a 5% discount rate and the valuations from Table 8, then the Columbus MSA would pay $154 in costs for each $1 in benefits. Most of the saved emissions would be in the 2030s, which reduces present values.

[52] 3% average for 2020 inflated to 2018 dollars, "The Social Cost of Carbon," *U.S. Environmental Protection Agency*, https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html

Economic Impact Results

This subsection summarizes the results of the economic impact analysis. While the previous section regarding the power market modeling reveals important differences in the results of the MB Scenario and the RO Scenario, these are less critical for the economic impact analysis.

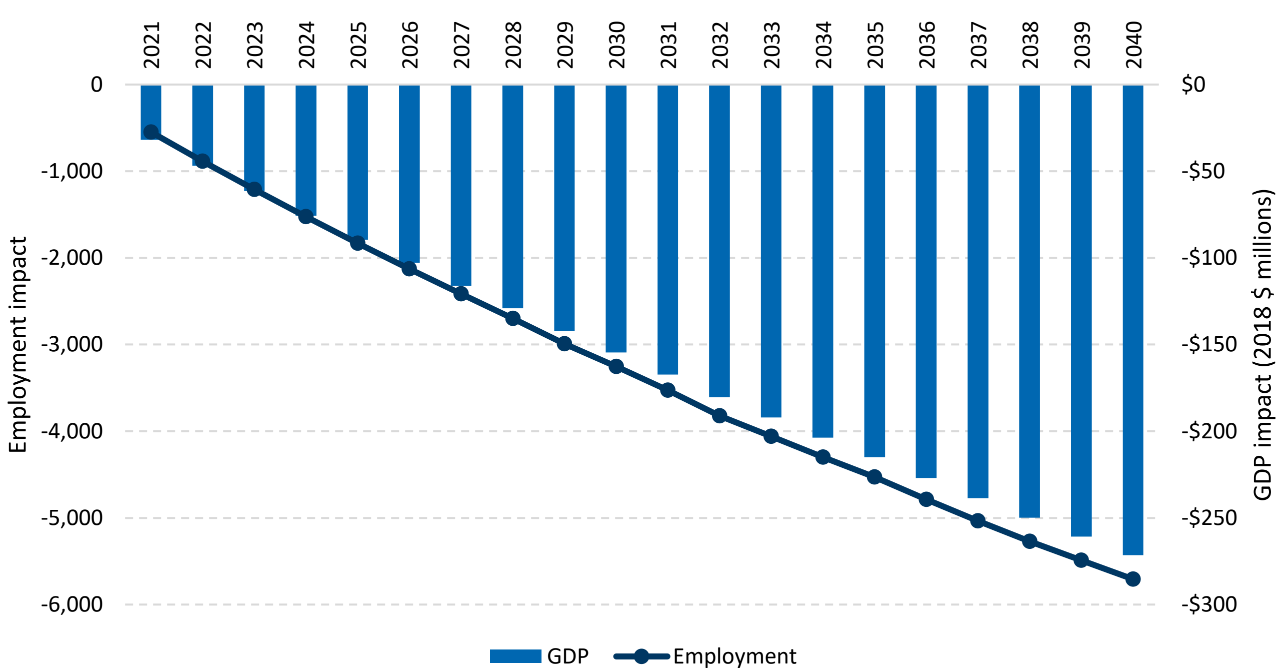
The main factors driving the economic impacts of electrifying the Columbus MSA's residential and commercial building stock would be the higher cost to customers to use electricity instead of natural gas for energy. These factors create the consumption reallocation and reduced competitiveness for industry described in the methodology section, and these are the main inputs into IMPLAN. Higher electricity prices are important though a secondary consideration.

Based on the scope of the study, we have reported only the economic impacts of the RO Scenario under the electrification scenarios. The economic impacts under the MB Scenario would be generally similar in magnitude and directionality to the results from the RO Scenario, and the same factors would drive results for both scenarios. Including both would be largely superfluous given the similarity of results between the scenarios and the limited additional insights to gain.

Macroeconomic Summary

Figure 15 summarizes the economic impact over time from the RO Scenario. The impacts would gradually increase as more and more homes and commercial structures undergo conversions, which would increase the costs borne by the Columbus MSA's economy for energy. In comparison to the Base Case by 2040, the Columbus MSA would have 5,700 fewer jobs and roughly $271 million less in GDP generated by the economy of the Columbus MSA otherwise.

Figure 15 – Economic impact of the RO Scenario compared to the Base Case



Employment Impacts

Table 9 describes the employment impacts from Figure 15 by economic sector for five-year increments between 2025 and 2040. Rather than leave the results in NAICS order,[53] we have sorted Table 9 in descending order based on 2040 results. Therefore, the sectors at the top of the list (such as power and construction) have the most positive impacts, and sectors at the bottom of the list (such as the healthcare sector or professional services) have the most negative ones. The effect across all the sectors would be negative – as much as 5,710 fewer jobs by 2040.

Table 9 – Employment impact of the RO Scenario by economic sector in 2040[54]

Economic Sector	2025	2030	2035	2040
Electric Power G, T, and D	240	430	610	770
Construction	90	120	160	180
S&L Government (Non-Education)	0	10	10	20
Coal Mining	0	0	0	0
Other Mining	0	0	0	0
S&L Government (Education)	0	0	0	0
Water and Sewage	0	0	0	0
Agriculture and Forestry	0	0	-10	-10
Federal Government	-10	-10	-20	-20
Manufacturing	-10	-10	-20	-20
Oil and Natural Gas Extraction	-10	-20	-30	-40
Information	-30	-50	-70	-90
Wholesale	-50	-100	-130	-170
Arts, Entertainment, and Recreation	-60	-110	-150	-180
Transportation and Logistics	-70	-130	-180	-230
Private Education	-80	-140	-200	-250
Natural Gas Distribution and Pipelines	-160	-290	-410	-510
Other Personal Services	-190	-320	-450	-560
Accommodation and Food Service	-230	-400	-550	-690
Finance, Insurance, and Real Estate	-240	-430	-610	-770
Retail	-250	-440	-620	-780
Professional and Business Services	-310	-550	-770	-970
Healthcare and Social Assistance	-460	-800	-1,100	-1,380
TOTAL	-1,830	-3,250	-4,530	-5,710

[53] North American Industrial Classification System
[54] Sectoral aggregations documented in the appendix

The results for Table 9 built upon the inputs described in the Methodology and Approach section and narrative several crucial trends for the economic impact of electrifying the Columbus MSA. We have organized these effects and trends into the following three categories:

1. The electric power generation, transmission, and distribution sector in the Columbus MSA would have a higher level of employment in the RO Scenario as compared to the Base Case. Because the energy demand of the Columbus MSA would gradually shift from natural gas distribution and its supply chain towards electricity and its supply chain, the latter sector would have increased employment. The construction sector in Table 9 would also have increased employment levels because of the increased labor costs to install electrified equipment ($2,224 versus $1,903 for homes per Table 4).
2. The first effect would be the upshot of more dollars flowing into the electricity sector and its supply chain, and the second effect would be its opposite – fewer dollars flowing into the gas supply chain and therefore contracting the sector. By 2040, Table 9 reports there would be 40 fewer oil and natural gas extraction jobs and 510 fewer natural gas distribution and pipeline transportation jobs in the Columbus MSA. Summing the losses from the gas sector would be less than the gains reported in Table 9 for the power sector. However, compared these alone does not account for the higher costs (from Table 4 and Table 5) for customers when using electricity instead of natural gas and consumption reallocation.
3. Most other economic sectors in Table 9 (stretching from information to healthcare and social assistance) would have fewer jobs under the RO Scenario. Under electrification, residential customers would trim their spending because of higher utility bills and commercial customers would pass some of their higher costs along to local households.

   Both effects would have a depressive influence on consumer spending in the Columbus MSA and for sectors primarily depending on expenditures by households. For instance, a household facing higher utility bills might choose to reduce its external food or shopping budget, which would negatively impact the foodservice and retail sectors, respectively. The results of such reallocation across the whole of the Columbus MSA's economy would add up to the thousands of jobs lost from electrification relative to the Base Case.

   Healthcare and social assistance would have the most negative impacts to jobs numbers by 2040, which makes the sector worthy of discussion. Much of healthcare spending is a baseline "need," but some types of healthcare (e.g., elective or cosmetic procedures or the amount of preventative care consumed by families) are "wants" and elastic to rising and falling incomes. Healthcare is a labor-intensive sector and, except for inpatient care, healthcare and social assistance are generally localized sectors without extensive import and export flows between metropolitan areas. All these in addition to the previous discussion on the large healthcare sector in the Columbus MSA would help to create the impact.

GDP Contributions

Table 10 recaps the change in GDP contribution by sector from IMPLAN. We use the same pattern of five-year increments between 2025 through 2040 and sort the results in descending order based on results from 2040 (which is the same format as in Table 9). The sectors with the greatest increase in their GDP contributions would include electric power generation, transmission, and distribution and construction. The sectors with the greatest decrease would include retail; professional and business services; healthcare and social assistance; finance, insurance, and real estate ("FIRE"); and sectors in natural gas' value chain, such as local gas distributors and gas pipelines.

Table 10 – GDP impact of the RO Scenario by economic sector in 2040 (2018 $ millions)

Economic Sector	2025	2030	2035	2040
Electric Power G, T, and D	$146.9	$269.7	$379.8	$478.1
Construction	$8.0	$11.4	$14.5	$17.1
S&L Government (Non-Education)	$3.3	$6.1	$8.7	$10.9
Coal Mining	$0.0	$0.0	$0.0	$0.0
Other Mining	$0.0	$0.0	$0.0	$0.0
S&L Government (Education)	$0.0	$0.0	$0.0	$0.0
Water and Sewage	$0.0	-$0.1	-$0.1	-$0.1
Agriculture and Forestry	-$0.1	-$0.1	-$0.1	-$0.2
Federal Government	-$0.6	-$1.0	-$1.4	-$1.8
Manufacturing	-$1.5	-$2.2	-$2.9	-$3.6
Arts, Entertainment, and Recreation	-$2.6	-$4.5	-$6.3	-$7.8
Oil and Natural Gas Extraction	-$2.6	-$4.7	-$6.6	-$8.2
Private Education	-$4.0	-$6.9	-$9.5	-$11.9
Transportation and Logistics	-$4.8	-$8.6	-$11.9	-$15.0
Wholesale	-$7.0	-$12.5	-$17.5	-$22.0
Information	-$6.8	-$12.2	-$17.4	-$22.4
Accommodation and Food Service	-$8.6	-$15.0	-$20.7	-$25.9
Other Personal Services	-$10.2	-$17.7	-$24.6	-$30.9
Retail	-$13.6	-$24.6	-$34.4	-$43.6
Professional and Business Services	-$25.7	-$45.8	-$64.0	-$80.6
Healthcare and Social Assistance	-$32.1	-$56.3	-$77.8	-$97.7
Finance, Insurance, and Real Estate	-$48.5	-$86.4	-$121.1	-$153.4
Natural Gas Distribution and Pipelines	-$79.2	-$143.3	-$201.7	-$252.5
TOTAL	-$89.5	-$154.6	-$215.0	-$271.4

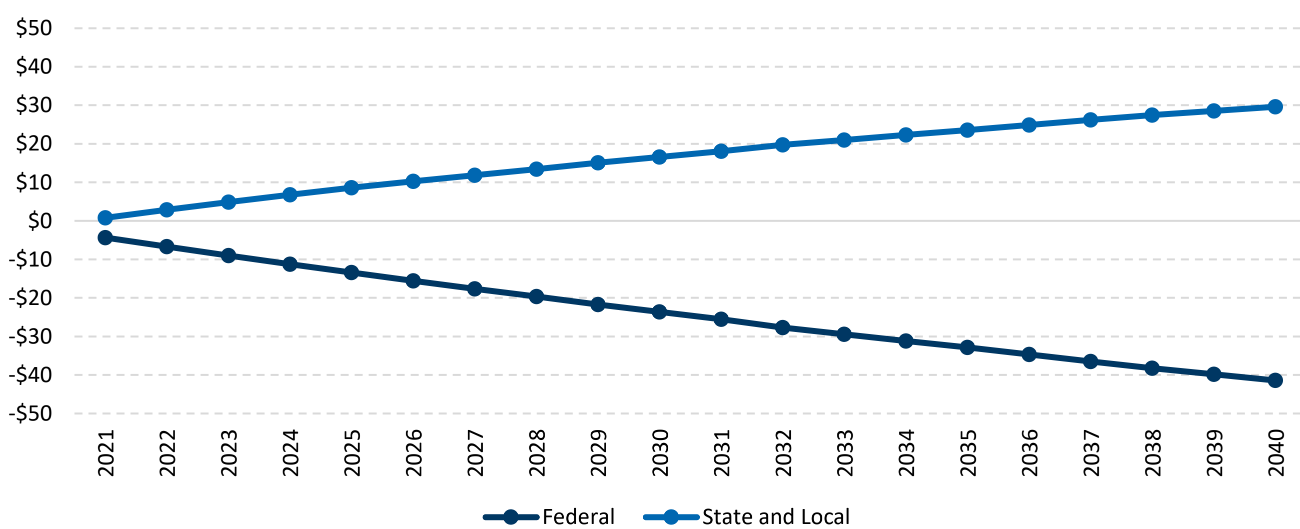
The driving forces behind the results in Table 10 would be generally the same as those for Table 9. The increase in expenditures for energy (and specifically electricity) under electrification would increase the GDP contribution of the electric power sector. The increase would come at the expense of natural gas distribution and pipelines. Because of the consumption reallocation, the sectors depending the most on local consumer expenditures would have reduced GDP contributions.

The most important difference between Table 9 and Table 10, accounting for the different ordering of the economic sectors, is labor productivity. Sectors such as healthcare or retail are labor-intensive, requiring higher levels of labor input to produce the same quantities of output as capital-intensive sectors. Examples of capital-intensive sectors include utilities, certain types of heavy manufacturers, and FIRE (especially the real estate sector). Table 10 examines only the GDP contribution by sector, while Table 9 adjust for labor productivity to show the impact on employment.

Tax Revenues

Figure 16 details the fiscal impact of the RO Scenario. The policy design would reduce tax revenues paid to the federal government yet increase them to state and local governments. By 2040 for the federal government, tax revenues would decrease by $41.4 million compared to the Base Case (and part of a cumulative decrease of $480.1 million over 20 years). With state and local governments, the increase in revenues for 2040 would be $29.6 million (a cumulative increase of $332.4 million relative to the scenario without electrification for the Columbus MSA).

Figure 16 – Tax revenue impact of the RO Scenario (2018 $ millions)

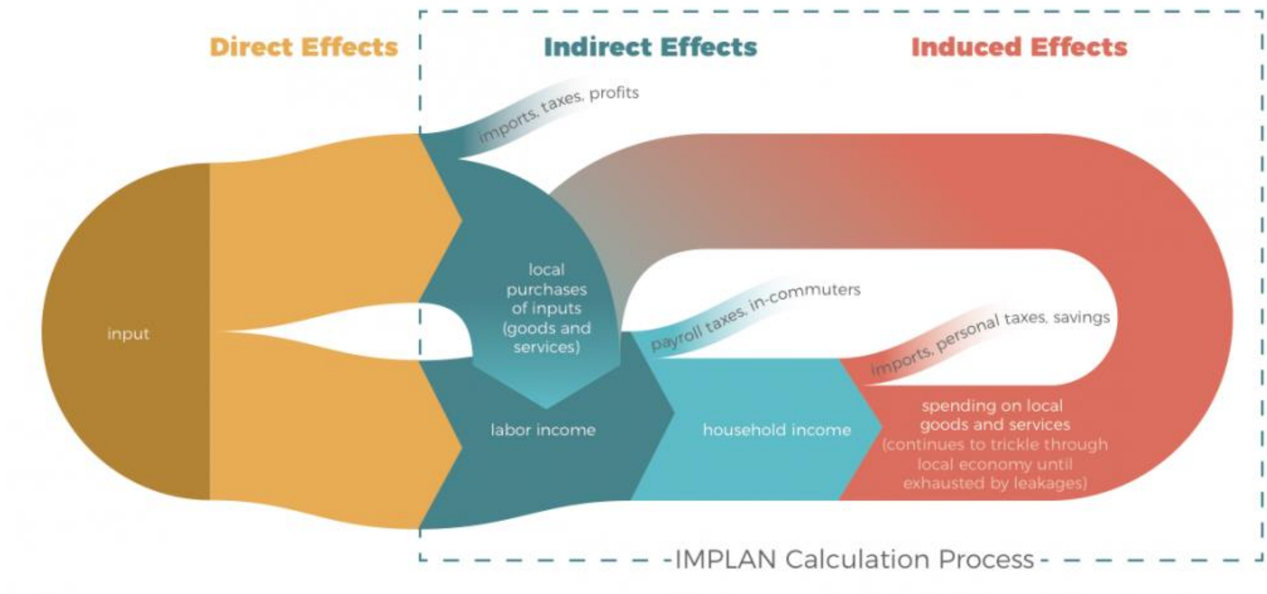


The contrasting results from Figure 16 might seem counterintuitive, though they follow the structure of federal, state, and local taxes in IMPLAN. Federal revenues strongly depend on labor markets. Jobs and income translate into payroll and income tax revenues, which are the main sources of federal revenues. State and local taxes rely on a mixture of income, sales, and property taxes along with fees. Fees, which include state and local utility fees and surcharges, would make up the difference between the revenue types in Figure 16 to the point that increase GDP contributions from electric power overcomes reduced tax revenues from reduced economic activity.

Appendix A – Model Diagrams

IMPLAN Model Diagram

Figure 17 – IMPLAN model diagram



PLEXOS Model Diagram

Figure 18 – PLEXOS model diagram

Inputs

New and Existing Units / Retrofits
- Individual units modeled, not aggregates
- Capital costs
- Variable and fixed O&M
- Efficiencies
- De-rates and uprates
- Availability
- Intermittency generation limits
- Dual-fuel capability
- Regional and national capacity expansion limitations

Fuel
- Gas and coal prices
- Gas infrastructure costs

Demand
- Peak growth
- Energy growth
- Demand side management and efficiency options

Environmental Regulations
- Existing and future

PLEXOS Model

The PLEXOS model is an integrated model that optimizes economic generation dispatch, unit commitment, and optimal power flow over a single interval as short as one-minute to daily, weekly, annual and multi-annual periods. In addition, it is run typically in a stochastic (probabilistic) fashion. PLEXOS also offers ancillary services analysis, hydroelectric capacity modeling, and natural gas infrastructure modeling.

Generation | Transmission | Expansion Planning | Hydro Modeling | Ancillary Services | Emissions | Gas Model | Financial

Outputs

Regional Capacity Changes
- New builds by type
- Retirements
- Retrofits

Generator performance by unit
- Generation
- Energy and capacity revenue
- Fuel consumption
- Capacity factors
- Emissions
- Cash flows

Market Prices by Region and Node
- Energy and capacity
- Renewable energy credits
- NOx, SO_2, and CO_2 allowances

Fuel demand
- Gas, fuel oil, and coal

Infrastructure
- Electrical and gas transmission flows and constraints
- Expansion

Appendix B – Load Shapes

Average Residential Customer

Table 11 – Average load by month and hour for the average residential customer (kWh)

HOUR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVG
0:00	3.01	1.58	1.61	1.07	0.29	0.23	0.23	0.23	0.24	0.61	1.48	1.72	1.02
1:00	3.25	1.83	1.98	1.19	0.32	0.23	0.23	0.23	0.24	0.71	1.50	1.92	1.14
2:00	3.28	1.89	1.97	1.33	0.32	0.23	0.23	0.23	0.24	0.72	1.61	1.92	1.16
3:00	3.31	1.84	2.06	1.34	0.31	0.23	0.23	0.23	0.24	0.74	1.68	1.92	1.18
4:00	3.23	2.02	2.14	1.40	0.34	0.23	0.23	0.23	0.24	0.74	1.74	1.73	1.19
5:00	3.28	1.98	2.07	1.41	0.33	0.23	0.23	0.23	0.24	0.72	1.59	2.15	1.21
6:00	2.93	1.89	2.10	1.43	0.29	0.23	0.23	0.23	0.24	0.70	1.62	2.11	1.16
7:00	3.68	1.80	1.88	1.13	0.26	0.23	0.23	0.23	0.24	0.68	1.64	1.97	1.16
8:00	3.56	1.65	1.66	1.05	0.24	0.23	0.23	0.23	0.24	0.59	1.60	2.01	1.11
9:00	3.30	1.50	1.48	0.89	0.23	0.23	0.23	0.23	0.23	0.54	1.42	1.75	1.00
10:00	2.67	1.44	1.29	0.92	0.23	0.23	0.23	0.23	0.23	0.50	1.28	1.61	0.90
11:00	3.05	1.32	1.26	0.83	0.23	0.23	0.23	0.23	0.23	0.48	1.34	1.29	0.89
12:00	2.84	1.29	1.15	0.81	0.23	0.23	0.23	0.23	0.23	0.44	1.21	1.30	0.85
13:00	2.60	1.38	1.13	0.79	0.23	0.23	0.23	0.23	0.23	0.42	1.25	1.26	0.83
14:00	2.60	1.37	1.10	0.75	0.23	0.23	0.23	0.23	0.23	0.39	1.22	1.28	0.82
15:00	2.57	1.35	1.08	0.74	0.23	0.23	0.23	0.23	0.23	0.42	1.22	1.34	0.82
16:00	2.57	1.43	1.12	0.76	0.23	0.23	0.23	0.23	0.23	0.46	1.27	1.34	0.84
17:00	2.91	1.49	1.21	0.74	0.23	0.23	0.23	0.23	0.23	0.49	1.24	1.54	0.90
18:00	2.37	1.49	1.30	0.81	0.23	0.23	0.23	0.23	0.23	0.56	1.22	1.51	0.87
19:00	2.92	1.53	1.40	0.91	0.24	0.23	0.23	0.23	0.23	0.57	1.53	1.67	0.97
20:00	3.03	1.72	1.48	0.97	0.24	0.23	0.23	0.23	0.23	0.60	1.49	1.64	1.01
21:00	2.79	1.82	1.70	1.02	0.25	0.23	0.23	0.23	0.23	0.65	1.46	1.86	1.04
22:00	3.02	1.88	1.75	1.06	0.27	0.23	0.23	0.23	0.24	0.62	1.32	1.72	1.05
23:00	3.02	1.73	1.68	1.06	0.28	0.23	0.23	0.23	0.24	0.61	1.40	1.72	1.03
AVG	2.99	1.63	1.57	1.02	0.26	0.23	0.23	0.23	0.23	0.58	1.43	1.68	1.01

Average Commercial Customer

Table 12 – Average load by month and hour for the average commercial customer (kWh)

HOUR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVG
0:00	24.22	14.25	14.47	10.13	4.76	4.85	4.76	4.87	4.90	7.68	13.07	14.79	10.23
1:00	25.93	16.00	17.07	10.92	4.76	4.88	4.76	4.92	4.94	8.42	13.19	16.14	10.99
2:00	26.15	16.40	16.97	11.77	4.76	4.89	4.76	4.97	4.94	8.56	13.95	16.14	11.19
3:00	26.32	16.04	17.59	11.85	4.76	4.90	4.76	4.98	4.92	8.70	14.37	16.09	11.27
4:00	25.78	17.32	18.17	12.20	4.76	4.92	4.76	5.07	4.94	8.68	14.80	14.85	11.35
5:00	26.13	17.01	17.70	12.31	4.76	4.89	4.76	5.04	4.95	8.55	13.77	17.67	11.46
6:00	23.64	16.42	17.85	12.39	4.76	4.82	4.76	4.91	4.95	8.38	14.01	17.38	11.19
7:00	28.91	15.79	16.34	10.51	4.76	4.79	4.76	4.79	4.91	8.18	14.15	16.48	11.20
8:00	28.07	14.75	14.78	10.02	4.76	4.79	4.76	4.76	4.88	7.50	13.84	16.72	10.80
9:00	26.24	13.71	13.53	9.02	4.76	4.78	4.76	4.76	4.83	7.17	12.70	14.96	10.10
10:00	21.84	13.30	12.22	9.15	4.76	4.78	4.76	4.76	4.81	6.84	11.74	14.02	9.42
11:00	24.48	12.41	12.01	8.60	4.76	4.78	4.76	4.76	4.79	6.73	12.16	11.92	9.35
12:00	23.04	12.22	11.21	8.48	4.76	4.77	4.76	4.76	4.79	6.37	11.27	11.95	9.03
13:00	21.36	12.86	11.08	8.34	4.76	4.77	4.76	4.76	4.78	6.24	11.57	11.66	8.91
14:00	21.38	12.75	10.89	8.06	4.76	4.76	4.76	4.76	4.79	5.99	11.35	11.84	8.84
15:00	21.11	12.65	10.74	8.01	4.76	4.76	4.76	4.76	4.79	6.26	11.32	12.25	8.85
16:00	21.14	13.17	10.99	8.13	4.76	4.76	4.76	4.76	4.79	6.53	11.67	12.22	8.97
17:00	23.49	13.58	11.63	8.06	4.76	4.76	4.76	4.76	4.80	6.80	11.49	13.55	9.37
18:00	19.75	13.64	12.28	8.46	4.76	4.76	4.76	4.76	4.84	7.34	11.32	13.33	9.17
19:00	23.58	13.89	13.00	9.13	4.76	4.78	4.76	4.77	4.85	7.38	13.37	14.47	9.89
20:00	24.35	15.24	13.53	9.50	4.76	4.79	4.76	4.78	4.85	7.62	13.13	14.21	10.13
21:00	22.72	15.91	15.10	9.81	4.76	4.77	4.76	4.80	4.87	8.02	12.94	15.72	10.35
22:00	24.31	16.34	15.46	10.04	4.76	4.80	4.76	4.84	4.92	7.75	12.00	14.76	10.40
23:00	24.26	15.30	14.96	10.09	4.76	4.83	4.76	4.85	4.91	7.72	12.54	14.78	10.31
AVG	24.09	14.62	14.15	9.79	4.76	4.81	4.76	4.83	4.86	7.48	12.74	14.50	10.12

Appendix C – Capacity Expansion Results

Base Case

Table 13 – Capacity additions in the Base Case (GW)

Year	Solar	Wind	Biomass	NGCC	Thermal Retirements	Net Additions
2021	4.3	1.0	0.2	0.0	0.0	5.4
2022	4.6	1.0	0.0	0.0	0.0	5.5
2023	5.5	0.4	0.0	0.0	0.6	5.3
2024	2.7	1.0	0.0	0.0	0.0	3.6
2025	5.5	0.5	0.0	0.5	0.0	6.4
2026	4.2	0.0	0.0	2.3	0.0	6.4
2027	5.5	0.4	0.0	0.0	1.6	4.3
2028	0.9	0.0	0.0	0.0	0.0	0.9
2029	3.2	0.0	0.0	0.0	0.0	3.2
2030	3.0	0.0	0.0	1.5	0.0	4.5
2031	3.0	0.0	0.0	0.5	0.0	3.6
2032	4.0	0.0	0.0	0.0	0.0	4.0
2033	0.0	0.0	0.0	0.0	0.4	-0.4
2034	0.2	0.0	0.0	1.5	0.0	1.6
2035	0.5	0.0	0.0	1.5	0.0	2.0
2036	0.4	0.0	0.0	1.5	0.0	1.9
2037	0.9	0.0	0.0	1.6	0.0	2.4
2038	0.5	0.0	0.0	0.3	0.0	0.8
2039	0.7	0.0	0.0	1.5	0.0	2.2
2040	0.4	0.0	0.0	2.0	0.0	2.5
TOTAL	49.9	4.1	0.2	14.6	2.6	66.2

Electrification – MB Scenario

Table 14 – Capacity additions under electrification for the MB Scenario (GW)

Year	Solar	Wind	Biomass	NGCC	Thermal Retirements	Net Additions
2021	4.3	1.0	0.2	0.0	0.0	5.4
2022	4.6	1.0	0.0	0.0	0.0	5.5
2023	5.5	0.4	0.0	0.0	0.6	5.3
2024	2.7	1.0	0.0	0.0	0.0	3.6
2025	5.5	0.5	0.0	0.6	0.0	6.5
2026	4.2	0.0	0.0	2.3	0.0	6.4
2027	5.5	0.4	0.0	0.0	1.6	4.3
2028	0.9	0.0	0.0	0.0	0.0	0.9
2029	3.2	0.0	0.0	0.0	0.0	3.2
2030	3.0	0.0	0.0	1.5	0.0	4.5
2031	3.0	0.0	0.0	1.2	0.0	4.3
2032	4.0	0.0	0.0	0.4	0.0	4.4
2033	0.0	0.0	0.0	0.0	0.4	-0.4
2034	0.2	0.0	0.0	1.5	0.0	1.7
2035	0.5	0.0	0.0	1.5	0.0	2.0
2036	0.4	0.0	0.0	1.5	0.0	1.9
2037	0.9	0.0	0.0	2.0	0.0	2.8
2038	0.5	0.0	0.0	0.0	0.0	0.5
2039	0.7	0.0	0.0	1.3	0.0	2.0
2040	0.4	0.0	0.0	2.1	0.0	2.5
TOTAL	49.9	4.1	0.2	15.8	2.6	67.4

Electrification – RO Scenario

Table 15 – Capacity additions under electrification for the RO Scenario (GW)

Year	Solar	Wind	Biomass	NGCC	Thermal Retirements	Net Additions
2021	4.3	1.0	0.2	0.0	0.0	5.5
2022	4.6	1.0	0.0	0.0	0.0	5.5
2023	5.5	0.4	0.0	0.0	0.6	5.3
2024	3.8	0.1	0.0	0.0	0.0	4.0
2025	5.5	0.5	0.0	0.5	0.0	6.4
2026	4.2	0.0	0.0	2.3	0.0	6.5
2027	5.5	1.0	0.0	0.0	1.6	4.9
2028	0.8	0.0	0.0	0.0	0.0	0.8
2029	3.5	0.0	0.0	0.0	0.0	3.5
2030	2.8	0.0	0.0	1.5	0.0	4.3
2031	3.1	0.0	0.0	0.5	0.0	3.7
2032	4.0	0.0	0.0	0.0	0.0	4.0
2033	0.1	0.0	0.0	0.0	0.4	-0.4
2034	0.3	0.0	0.0	1.5	0.0	1.8
2035	0.0	0.0	0.0	1.5	0.0	1.5
2036	0.9	0.0	0.0	1.5	0.0	2.4
2037	0.9	0.0	0.0	1.6	0.0	2.5
2038	1.8	0.0	0.0	0.3	0.0	2.0
2039	0.0	0.0	0.0	1.5	0.0	1.5
2040	0.3	0.0	0.0	2.0	0.0	2.3
TOTAL	51.9	3.9	0.2	14.6	2.6	68.1

Appendix D – Emissions Results

Emissions Results – Base Case

Table 16 – Base Case emissions

Year	CO_2 (millions of metric tons)	NOx (thousands of short tons)	SO_2 (thousands of short tons)
2021	312.0	165.0	241.0
2022	310.1	160.3	227.0
2023	300.0	155.6	218.2
2024	298.6	155.2	216.2
2025	285.2	144.8	198.3
2026	277.2	137.9	190.6
2027	273.6	136.1	192.8
2028	277.3	140.2	200.9
2029	274.8	139.3	195.2
2030	271.8	135.2	187.6
2031	277.2	138.2	192.9
2032	284.5	144.0	203.8
2033	292.0	148.1	209.4
2034	291.1	145.9	205.6
2035	298.6	149.3	211.7
2036	305.1	151.7	216.0
2037	309.9	151.4	214.4
2038	321.8	157.4	220.7
2039	324.5	156.9	220.3
2040	312.2	145.0	197.2
TOTAL	5,897.3	2,957.5	4,159.6

Emissions Results – MB Scenario

Table 17 – CO2 emissions (millions of metric tons)

Year	Base Case (Total)	MB (PJM)	Difference (PJM)	Percentage (PJM)	Difference (Imports)	Difference (Total)
2021	312.0	312.1	0.1	0.0%	0.1	0.2
2022	310.1	310.4	0.3	0.1%	0.1	0.4
2023	300.0	300.7	0.7	0.2%	0.5	1.2
2024	298.6	299.8	1.2	0.4%	0.2	1.4
2025	285.2	286.4	1.2	0.4%	0.3	1.6
2026	277.2	278.8	1.6	0.6%	0.5	2.1
2027	273.6	275.7	2.1	0.8%	0.3	2.4
2028	277.3	279.6	2.3	0.8%	0.4	2.7
2029	274.8	277.3	2.5	0.9%	0.4	3.0
2030	271.8	274.5	2.6	1.0%	0.8	3.4
2031	277.2	279.4	2.1	0.8%	0.3	2.4
2032	284.5	285.9	1.4	0.5%	-0.4	1.0
2033	292.0	294.0	2.0	0.7%	0.3	2.3
2034	291.1	293.2	2.1	0.7%	0.4	2.5
2035	298.6	301.2	2.6	0.9%	0.2	2.8
2036	305.1	308.0	3.0	1.0%	0.8	3.7
2037	309.9	312.2	2.3	0.7%	-0.2	2.1
2038	321.8	325.2	3.4	1.1%	0.4	3.8
2039	324.5	328.3	3.8	1.2%	1.4	5.2
2040	312.2	316.1	3.9	1.3%	0.3	4.2
TOTAL	5,897.3	5,938.6	41.2	0.7%	7.0	48.3

Table 18 – NOx emissions (thousands of short tons)

Year	Base Case (Total)	MB (PJM)	Difference (PJM)	Percentage (PJM)	Difference (Imports)	Difference (Total)
2021	165.0	165.1	0.1	0.0%	0.0	0.1
2022	160.3	160.5	0.1	0.1%	-0.1	0.0
2023	155.6	155.9	0.3	0.2%	0.4	0.7
2024	155.2	155.7	0.6	0.4%	0.2	0.8
2025	144.8	145.4	0.5	0.4%	0.2	0.7
2026	137.9	138.7	0.8	0.6%	0.2	1.0
2027	136.1	137.1	1.0	0.8%	0.0	1.1
2028	140.2	141.3	1.1	0.8%	0.2	1.3
2029	139.3	140.5	1.2	0.9%	0.3	1.4
2030	135.2	136.5	1.3	1.0%	0.4	1.7
2031	138.2	138.4	0.2	0.2%	0.3	0.5
2032	144.0	143.5	-0.4	-0.3%	-0.9	-1.3
2033	148.1	147.7	-0.4	-0.3%	0.2	-0.2
2034	145.9	145.6	-0.3	-0.2%	0.3	0.0
2035	149.3	149.2	-0.1	-0.1%	0.2	0.1
2036	151.7	151.7	0.0	0.0%	0.6	0.6
2037	151.4	150.7	-0.8	-0.5%	-0.2	-0.9
2038	157.4	157.6	0.2	0.1%	0.0	0.2
2039	156.9	157.6	0.7	0.5%	0.8	1.5
2040	145.0	145.6	0.6	0.4%	0.0	0.6
TOTAL	2,957.5	2,964.3	6.8	0.2%	3.2	10.0

Table 19 – SO2 emissions (thousands of short tons)

Year	Base Case (Total)	MB (PJM)	Difference (PJM)	Percentage (PJM)	Difference (Imports)	Difference (Total)
2021	241.0	241.0	0.0	0.0%	0.0	0.1
2022	227.0	227.1	0.1	0.1%	0.1	0.3
2023	218.2	218.5	0.3	0.1%	0.5	0.8
2024	216.2	216.7	0.6	0.3%	0.5	1.0
2025	198.3	198.7	0.4	0.2%	0.2	0.6
2026	190.6	191.6	1.0	0.5%	0.5	1.5
2027	192.8	194.0	1.2	0.6%	0.1	1.4
2028	200.9	202.3	1.4	0.7%	0.3	1.6
2029	195.2	196.3	1.0	0.5%	0.3	1.3
2030	187.6	188.7	1.1	0.6%	0.8	1.9
2031	192.9	192.7	-0.2	-0.1%	0.1	-0.1
2032	203.8	202.7	-1.2	-0.6%	-0.2	-1.4
2033	209.4	208.6	-0.9	-0.4%	0.4	-0.4
2034	205.6	204.6	-1.0	-0.5%	0.3	-0.6
2035	211.7	211.1	-0.6	-0.3%	0.1	-0.5
2036	216.0	215.6	-0.4	-0.2%	0.7	0.3
2037	214.4	213.1	-1.3	-0.6%	-0.4	-1.7
2038	220.7	220.4	-0.3	-0.1%	-0.2	-0.4
2039	220.3	220.2	0.0	0.0%	0.6	0.6
2040	197.2	197.1	-0.1	0.0%	-1.2	-1.3
TOTAL	4,159.6	4,160.9	1.3	0.0%	3.7	5.0

Emissions Results – RO Scenario

Table 20 – CO2 emissions (millions of metric tons)

Year	Base Case (Total)	RO (PJM)	Difference (PJM)	Percentage (PJM)	Difference (Imports)	Difference (Total)
2021	312.0	312.1	0.1	0.0%	0.1	0.2
2022	310.1	310.4	0.3	0.1%	0.1	0.5
2023	300.0	300.7	0.6	0.2%	0.1	0.8
2024	298.6	299.9	1.3	0.4%	-0.2	1.1
2025	285.2	286.7	1.5	0.5%	0.1	1.6
2026	277.2	279.1	1.9	0.7%	0.3	2.2
2027	273.6	275.8	2.3	0.8%	-0.1	2.1
2028	277.3	279.7	2.4	0.9%	0.1	2.5
2029	274.8	277.4	2.7	1.0%	0.2	2.8
2030	271.8	274.6	2.8	1.0%	0.5	3.3
2031	277.2	280.3	3.1	1.1%	0.7	3.8
2032	284.5	286.9	2.5	0.9%	-0.6	1.9
2033	292.0	295.2	3.1	1.1%	1.2	4.3
2034	291.1	294.6	3.6	1.2%	1.4	4.9
2035	298.6	302.8	4.2	1.4%	1.2	5.3
2036	305.1	309.4	4.3	1.4%	1.2	5.5
2037	309.9	314.8	4.9	1.6%	1.1	6.0
2038	321.8	326.2	4.4	1.4%	0.5	4.9
2039	324.5	328.8	4.4	1.3%	1.9	6.2
2040	312.2	317.1	4.9	1.6%	0.9	5.8
TOTAL	5,897.3	5,952.6	55.3	0.9%	10.3	65.6

Table 21 – NOx emissions (thousands of short tons)

Year	Base Case (Total)	RO (PJM)	Difference (PJM)	Percentage (PJM)	Difference (Imports)	Difference (Total)
2021	165.0	165.1	0.1	0.0%	-0.1	0.0
2022	160.3	160.5	0.1	0.1%	-0.1	0.0
2023	155.6	155.9	0.3	0.2%	0.2	0.4
2024	155.2	155.8	0.7	0.4%	0.0	0.6
2025	144.8	145.6	0.8	0.5%	0.0	0.8
2026	137.9	139.1	1.1	0.8%	0.2	1.4
2027	136.1	137.4	1.3	0.9%	-0.1	1.2
2028	140.2	141.5	1.3	0.9%	0.1	1.3
2029	139.3	140.7	1.4	1.0%	0.2	1.6
2030	135.2	136.7	1.5	1.1%	0.3	1.8
2031	138.2	139.8	1.6	1.2%	0.4	2.0
2032	144.0	145.3	1.3	0.9%	-1.5	-0.1
2033	148.1	149.6	1.5	1.0%	0.5	2.0
2034	145.9	147.7	1.8	1.2%	0.8	2.6
2035	149.3	151.2	1.9	1.3%	0.5	2.4
2036	151.7	153.5	1.8	1.2%	0.7	2.5
2037	151.4	153.8	2.4	1.6%	0.6	2.9
2038	157.4	159.6	2.2	1.4%	0.3	2.5
2039	156.9	158.9	2.0	1.2%	0.9	2.8
2040	145.0	147.5	2.5	1.7%	0.0	2.5
TOTAL	2,957.5	2,985.0	27.5	0.9%	3.8	31.3

Table 22 – SO2 emissions (thousands of short tons)

Year	Base Case (Total)	RO (PJM)	Difference (PJM)	Percentage (PJM)	Difference (Imports)	Difference (Total)
2021	241.0	241.0	0.1	0.0%	0.0	0.1
2022	227.0	227.1	0.1	0.1%	0.2	0.3
2023	218.2	218.5	0.3	0.2%	0.4	0.7
2024	216.2	216.9	0.7	0.3%	0.2	0.9
2025	198.3	199.0	0.8	0.4%	0.1	0.9
2026	190.6	192.0	1.4	0.7%	0.6	2.0
2027	192.8	194.4	1.6	0.9%	0.2	1.8
2028	200.9	202.6	1.7	0.9%	0.2	2.0
2029	195.2	196.8	1.5	0.8%	0.4	1.9
2030	187.6	189.1	1.5	0.8%	0.8	2.3
2031	192.9	194.8	1.9	1.0%	0.5	2.4
2032	203.8	205.3	1.4	0.7%	-1.1	0.4
2033	209.4	211.0	1.6	0.8%	0.9	2.5
2034	205.6	207.5	1.9	0.9%	1.2	3.1
2035	211.7	214.1	2.4	1.1%	1.0	3.4
2036	216.0	217.9	2.0	0.9%	1.4	3.3
2037	214.4	217.4	3.0	1.4%	0.6	3.6
2038	220.7	222.4	1.8	0.8%	0.4	2.2
2039	220.3	221.5	1.2	0.6%	1.4	2.7
2040	197.2	199.5	2.3	1.2%	-0.2	2.1
TOTAL	4,159.6	4,188.9	29.2	0.7%	9.1	38.4

Emissions Results – CO2 in the Base Case, MB Scenario, and RO Scenario

Table 23 – Energy demand and CO2 emissions (millions of metric tons)

Year	Gas Demand (MMcf)	Base Case (CO2)	MB Scenario (CO2)	RO Scenario (CO2)	MB minus Base Case (CO2)	RO minus Base Case (CO2)
2021	2,086	0.1	0.2	0.2	0.1	0.1
2022	7,104	0.4	0.4	0.5	0.1	0.1
2023	12,123	0.6	1.2	0.8	0.6	0.1
2024	17,142	0.9	1.4	1.1	0.5	0.2
2025	22,160	1.2	1.6	1.6	0.4	0.4
2026	27,178	1.4	2.1	2.2	0.6	0.8
2027	32,197	1.7	2.4	2.1	0.6	0.4
2028	37,216	2.0	2.7	2.5	0.7	0.5
2029	42,234	2.2	3.0	2.8	0.7	0.6
2030	47,252	2.5	3.4	3.3	0.9	0.8
2031	52,271	2.8	2.4	3.8	-0.4	1.0
2032	57,290	3.0	1.0	1.9	-2.0	-1.1
2033	62,308	3.3	2.3	4.3	-1.0	1.0
2034	67,326	3.6	2.5	4.9	-1.0	1.3
2035	72,345	3.8	2.8	5.3	-1.0	1.5
2036	77,364	4.1	3.7	5.5	-0.4	1.4
2037	82,382	4.4	2.1	6.0	-2.3	1.6
2038	87,400	4.6	3.8	4.9	-0.8	0.2
2039	92,419	4.9	5.2	6.2	0.3	1.3
2040	97,438	5.2	4.2	5.8	-1.0	0.6
TOTAL	995,234	52.9	48.3	65.6	-4.6	12.8

Emissions Results – NOx in the Base Case, MB Scenario, and RO Scenario

Table 24 – Energy demand and CO2 emissions (thousands of short tons)

Year	Gas Demand (MMcf)	Base Case (NOx)	MB Scenario (NOx)	RO Scenario (NOx)	MB minus Base Case (NOx)	RO minus Base Case (NOx)
2021	2,086	0.1	0.1	0.0	0.0	-0.1
2022	7,104	0.4	0.0	0.0	-0.4	-0.4
2023	12,123	0.7	0.7	0.4	-0.1	-0.3
2024	17,142	1.0	0.8	0.6	-0.2	-0.4
2025	22,160	1.3	0.7	0.8	-0.6	-0.5
2026	27,178	1.6	1.0	1.4	-0.6	-0.2
2027	32,197	1.9	1.1	1.2	-0.8	-0.7
2028	37,216	2.2	1.3	1.3	-0.9	-0.8
2029	42,234	2.5	1.4	1.6	-1.0	-0.9
2030	47,252	2.8	1.7	1.8	-1.0	-1.0
2031	52,271	3.1	0.5	2.0	-2.6	-1.1
2032	57,290	3.4	-1.3	-0.1	-4.7	-3.5
2033	62,308	3.6	-0.2	2.0	-3.9	-1.6
2034	67,326	3.9	0.0	2.6	-3.9	-1.4
2035	72,345	4.2	0.1	2.4	-4.1	-1.8
2036	77,364	4.5	0.6	2.5	-3.9	-2.0
2037	82,382	4.8	-0.9	2.9	-5.7	-1.9
2038	87,400	5.1	0.2	2.5	-4.9	-2.7
2039	92,419	5.4	1.5	2.8	-3.9	-2.6
2040	97,438	5.7	0.6	2.5	-5.1	-3.2
TOTAL	995,234	58.2	10.0	31.3	-48.2	-26.9

Emissions Results – SO2 in the Base Case, MB Scenario, and RO Scenario

Table 25 – Energy demand and CO2 emissions (thousands of short tons)

Year	Gas Demand (MMcf)	Base Case (SO2)	MB Scenario (SO2)	RO Scenario (SO2)	MB minus Base Case (SO2)	RO minus Base Case (SO2)
2021	2,086	0.0	0.1	0.1	0.1	0.1
2022	7,104	0.0	0.3	0.3	0.3	0.3
2023	12,123	0.0	0.8	0.7	0.8	0.7
2024	17,142	0.0	1.0	0.9	1.0	0.9
2025	22,160	0.0	0.6	0.9	0.6	0.9
2026	27,178	0.0	1.5	2.0	1.5	2.0
2027	32,197	0.0	1.4	1.8	1.3	1.8
2028	37,216	0.0	1.6	2.0	1.6	2.0
2029	42,234	0.0	1.3	1.9	1.3	1.9
2030	47,252	0.0	1.9	2.3	1.9	2.3
2031	52,271	0.0	-0.1	2.4	-0.1	2.4
2032	57,290	0.0	-1.4	0.4	-1.4	0.4
2033	62,308	0.0	-0.4	2.5	-0.5	2.5
2034	67,326	0.0	-0.6	3.1	-0.7	3.1
2035	72,345	0.0	-0.5	3.4	-0.5	3.4
2036	77,364	0.0	0.3	3.3	0.3	3.3
2037	82,382	0.0	-1.7	3.6	-1.7	3.6
2038	87,400	0.0	-0.4	2.2	-0.5	2.2
2039	92,419	0.0	0.6	2.7	0.6	2.7
2040	97,438	0.0	-1.3	2.1	-1.3	2.1
TOTAL	995,234	0.5	5.0	38.6	4.5	38.1

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Appendix E – IMPLAN Sectoral Aggregation

Sectoral Aggregation

Table 26 – Sectoral aggregation from IMPLAN to economic impact results

Sector ID	IMPLAN Sector	Aggregation
1	Oilseed farming	Agriculture and Forestry
2	Grain farming	Agriculture and Forestry
3	Vegetable and melon farming	Agriculture and Forestry
4	Fruit farming	Agriculture and Forestry
5	Tree nut farming	Agriculture and Forestry
6	Greenhouse, nursery, and floricult…	Agriculture and Forestry
7	Tobacco farming	Agriculture and Forestry
8	Cotton farming	Agriculture and Forestry
9	Sugarcane and sugar beet farming	Agriculture and Forestry
10	All other crop farming	Agriculture and Forestry
11	Beef cattle ranching and farming, …	Agriculture and Forestry
12	Dairy cattle and milk production	Agriculture and Forestry
13	Poultry and egg production	Agriculture and Forestry
14	Animal production, except cattle a…	Agriculture and Forestry
15	Forestry, forest products, and tim…	Agriculture and Forestry
16	Commercial logging	Agriculture and Forestry
17	Commercial fishing	Agriculture and Forestry
18	Commercial hunting and trapping	Agriculture and Forestry
19	Support activities for agriculture…	Agriculture and Forestry
20	Oil and gas extraction	Oil and Natural Gas Extraction
21	Coal mining	Coal Mining
22	Copper, nickel, lead, and zinc min…	Other Mining
23	Iron ore mining	Other Mining
24	Gold ore mining	Other Mining
25	Silver ore mining	Other Mining
26	Uranium-radium-vanadium ore mining	Other Mining
27	Other metal ore mining	Other Mining
28	Stone mining and quarrying	Other Mining
29	Sand and gravel mining	Other Mining
30	Other clay, ceramic, refractory mi…	Other Mining
31	Potash, soda, and borate mineral m…	Other Mining
32	Phosphate rock mining	Other Mining
33	Other chemical and fertilizer mine…	Other Mining

34	Other nonmetallic minerals	Other Mining
35	Drilling oil and gas wells	Oil and Natural Gas Extraction
36	Support activities for oil and gas…	Oil and Natural Gas Extraction
37	Metal mining services	Other Mining
38	Other nonmetallic minerals service…	Other Mining
39	Electric power generation - Hydroe…	Electric Power G, T, and D
40	Electric power generation - Fossil…	Electric Power G, T, and D
41	Electric power generation - Nuclea…	Electric Power G, T, and D
42	Electric power generation - Solar	Electric Power G, T, and D
43	Electric power generation - Wind	Electric Power G, T, and D
44	Electric power generation - Geothe…	Electric Power G, T, and D
45	Electric power generation - Biomas…	Electric Power G, T, and D
46	Electric power generation - All ot…	Electric Power G, T, and D
47	Electric power transmission and di…	Electric Power G, T, and D
48	Natural gas distribution	Natural Gas Distribution and Pipelines
49	Water, sewage and other systems	Water and Sewage
50	Construction of new health care st…	Construction
51	Construction of new manufacturing …	Construction
52	Construction of new power and comm…	Construction
53	Construction of new educational an…	Construction
54	Construction of new highways and s…	Construction
55	Construction of new commercial str…	Construction
56	Construction of other new nonresid…	Construction
57	Construction of new single-family …	Construction
58	Construction of new multifamily re…	Construction
59	Construction of other new resident…	Construction
60	Maintenance and repair constructio…	Construction
61	Maintenance and repair constructio…	Construction
62	Maintenance and repair constructio…	Construction
63	Dog and cat food manufacturing	Manufacturing
64	Other animal food manufacturing	Manufacturing
65	Flour milling	Manufacturing
66	Rice milling	Manufacturing
67	Malt manufacturing	Manufacturing
68	Wet corn milling	Manufacturing
69	Soybean and other oilseed processi…	Manufacturing
70	Fats and oils refining and blendin…	Manufacturing
71	Breakfast cereal manufacturing	Manufacturing

72	Beet sugar manufacturing	Manufacturing
73	Sugar cane mills and refining	Manufacturing
74	Nonchocolate confectionery manufac…	Manufacturing
75	Chocolate and confectionery manufa…	Manufacturing
76	Confectionery manufacturing from p…	Manufacturing
77	Frozen fruits, juices and vegetabl…	Manufacturing
78	Frozen specialties manufacturing	Manufacturing
79	Canned fruits and vegetables manuf…	Manufacturing
80	Canned specialties	Manufacturing
81	Dehydrated food products manufactu…	Manufacturing
82	Cheese manufacturing	Manufacturing
83	Dry, condensed, and evaporated dai…	Manufacturing
84	Fluid milk manufacturing	Manufacturing
85	Creamery butter manufacturing	Manufacturing
86	Ice cream and frozen dessert manuf…	Manufacturing
87	Frozen cakes and other pastries ma…	Manufacturing
88	Poultry processing	Manufacturing
89	Animal, except poultry, slaughteri…	Manufacturing
90	Meat processed from carcasses	Manufacturing
91	Rendering and meat byproduct proce…	Manufacturing
92	Seafood product preparation and pa…	Manufacturing
93	Bread and bakery product, except f…	Manufacturing
94	Cookie and cracker manufacturing	Manufacturing
95	Dry pasta, mixes, and dough manufa…	Manufacturing
96	Tortilla manufacturing	Manufacturing
97	Roasted nuts and peanut butter man…	Manufacturing
98	Other snack food manufacturing	Manufacturing
99	Coffee and tea manufacturing	Manufacturing
100	Flavoring syrup and concentrate ma…	Manufacturing
101	Mayonnaise, dressing, and sauce ma…	Manufacturing
102	Spice and extract manufacturing	Manufacturing
103	All other food manufacturing	Manufacturing
104	Bottled and canned soft drinks & w…	Manufacturing
105	Manufactured ice	Manufacturing
106	Breweries	Manufacturing
107	Wineries	Manufacturing
108	Distilleries	Manufacturing
109	Tobacco product manufacturing	Manufacturing

110	Fiber, yarn, and thread mills	Manufacturing
111	Broadwoven fabric mills	Manufacturing
112	Narrow fabric mills and schiffli m…	Manufacturing
113	Nonwoven fabric mills	Manufacturing
114	Knit fabric mills	Manufacturing
115	Textile and fabric finishing mills	Manufacturing
116	Fabric coating mills	Manufacturing
117	Carpet and rug mills	Manufacturing
118	Curtain and linen mills	Manufacturing
119	Textile bag and canvas mills	Manufacturing
120	Rope, cordage, twine, tire cord an…	Manufacturing
121	Other textile product mills	Manufacturing
122	Hosiery and sock mills	Manufacturing
123	Other apparel knitting mills	Manufacturing
124	Cut and sew apparel contractors	Manufacturing
125	Mens and boys cut and sew apparel …	Manufacturing
126	Womens and girls cut and sew appar…	Manufacturing
127	Other cut and sew apparel manufact…	Manufacturing
128	Apparel accessories and other appa…	Manufacturing
129	Leather and hide tanning and finis…	Manufacturing
130	Footwear manufacturing	Manufacturing
131	Other leather and allied product m…	Manufacturing
132	Sawmills	Manufacturing
133	Wood preservation	Manufacturing
134	Veneer and plywood manufacturing	Manufacturing
135	Engineered wood member and truss m…	Manufacturing
136	Reconstituted wood product manufac…	Manufacturing
137	Wood windows and door manufacturin…	Manufacturing
138	Cut stock, resawing lumber, and pl…	Manufacturing
139	Other millwork, including flooring	Manufacturing
140	Wood container and pallet manufact…	Manufacturing
141	Manufactured home (mobile home) ma…	Manufacturing
142	Prefabricated wood building manufa…	Manufacturing
143	All other miscellaneous wood produ…	Manufacturing
144	Pulp mills	Manufacturing
145	Paper mills	Manufacturing
146	Paperboard mills	Manufacturing
147	Paperboard container manufacturing	Manufacturing

148	Paper bag and coated and treated p...	Manufacturing
149	Stationery product manufacturing	Manufacturing
150	Sanitary paper product manufacturi...	Manufacturing
151	All other converted paper product ...	Manufacturing
152	Printing	Manufacturing
153	Support activities for printing	Manufacturing
154	Petroleum refineries	Manufacturing
155	Asphalt paving mixture and block m...	Manufacturing
156	Asphalt shingle and coating materi...	Manufacturing
157	Petroleum lubricating oil and grea...	Manufacturing
158	All other petroleum and coal produ...	Manufacturing
159	Petrochemical manufacturing	Manufacturing
160	Industrial gas manufacturing	Manufacturing
161	Synthetic dye and pigment manufact...	Manufacturing
162	Other basic inorganic chemical man...	Manufacturing
163	Other basic organic chemical manuf...	Manufacturing
164	Plastics material and resin manufa...	Manufacturing
165	Synthetic rubber manufacturing	Manufacturing
166	Artificial and synthetic fibers an...	Manufacturing
167	Nitrogenous fertilizer manufacturi...	Manufacturing
168	Phosphatic fertilizer manufacturin...	Manufacturing
169	Fertilizer mixing	Manufacturing
170	Pesticide and other agricultural c...	Manufacturing
171	Medicinal and botanical manufactur...	Manufacturing
172	Pharmaceutical preparation manufac...	Manufacturing
173	In-vitro diagnostic substance manu...	Manufacturing
174	Biological product (except diagnos...	Manufacturing
175	Paint and coating manufacturing	Manufacturing
176	Adhesive manufacturing	Manufacturing
177	Soap and other detergent manufactu...	Manufacturing
178	Polish and other sanitation good m...	Manufacturing
179	Surface active agent manufacturing	Manufacturing
180	Toilet preparation manufacturing	Manufacturing
181	Printing ink manufacturing	Manufacturing
182	Explosives manufacturing	Manufacturing
183	Custom compounding of purchased re...	Manufacturing
184	Photographic film and chemical man...	Manufacturing
185	Other miscellaneous chemical produ...	Manufacturing

186	Plastics packaging materials and u...	Manufacturing
187	Unlaminated plastics profile shape...	Manufacturing
188	Plastics pipe and pipe fitting man...	Manufacturing
189	Laminated plastics plate, sheet (e...	Manufacturing
190	Polystyrene foam product manufactu...	Manufacturing
191	Urethane and other foam product (e...	Manufacturing
192	Plastics bottle manufacturing	Manufacturing
193	Other plastics product manufacturi...	Manufacturing
194	Tire manufacturing	Manufacturing
195	Rubber and plastics hoses and belt...	Manufacturing
196	Other rubber product manufacturing	Manufacturing
197	Pottery, ceramics, and plumbing fi...	Manufacturing
198	Brick, tile, and other structural ...	Manufacturing
199	Flat glass manufacturing	Manufacturing
200	Other pressed and blown glass and ...	Manufacturing
201	Glass container manufacturing	Manufacturing
202	Glass product manufacturing made o...	Manufacturing
203	Cement manufacturing	Manufacturing
204	Ready-mix concrete manufacturing	Manufacturing
205	Concrete block and brick manufactu...	Manufacturing
206	Concrete pipe manufacturing	Manufacturing
207	Other concrete product manufacturi...	Manufacturing
208	Lime manufacturing	Manufacturing
209	Gypsum product manufacturing	Manufacturing
210	Abrasive product manufacturing	Manufacturing
211	Cut stone and stone product manufa...	Manufacturing
212	Ground or treated mineral and eart...	Manufacturing
213	Mineral wool manufacturing	Manufacturing
214	Miscellaneous nonmetallic mineral ...	Manufacturing
215	Iron and steel mills and ferroallo...	Manufacturing
216	Iron, steel pipe and tube manufact...	Manufacturing
217	Rolled steel shape manufacturing	Manufacturing
218	Steel wire drawing	Manufacturing
219	Alumina refining and primary alumi...	Manufacturing
220	Secondary smelting and alloying of...	Manufacturing
221	Aluminum sheet, plate, and foil ma...	Manufacturing
222	Other aluminum rolling, drawing an...	Manufacturing
223	Nonferrous metal (exc aluminum) sm...	Manufacturing

224	Copper rolling, drawing, extruding…	Manufacturing
225	Nonferrous metal, except copper an…	Manufacturing
226	Secondary processing of other nonf…	Manufacturing
227	Ferrous metal foundries	Manufacturing
228	Nonferrous metal foundries	Manufacturing
229	Custom roll forming	Manufacturing
230	Crown and closure manufacturing an…	Manufacturing
231	Iron and steel forging	Manufacturing
232	Nonferrous forging	Manufacturing
233	Cutlery, utensil, pot, and pan man…	Manufacturing
234	Handtool manufacturing	Manufacturing
235	Prefabricated metal buildings and …	Manufacturing
236	Fabricated structural metal manufa…	Manufacturing
237	Plate work manufacturing	Manufacturing
238	Metal window and door manufacturin…	Manufacturing
239	Sheet metal work manufacturing	Manufacturing
240	Ornamental and architectural metal…	Manufacturing
241	Power boiler and heat exchanger ma…	Manufacturing
242	Metal tank (heavy gauge) manufactu…	Manufacturing
243	Metal cans manufacturing	Manufacturing
244	Metal barrels, drums and pails man…	Manufacturing
245	Hardware manufacturing	Manufacturing
246	Spring and wire product manufactur…	Manufacturing
247	Machine shops	Manufacturing
248	Turned product and screw, nut, and…	Manufacturing
249	Metal heat treating	Manufacturing
250	Metal coating and nonprecious engr…	Manufacturing
251	Electroplating, anodizing, and col…	Manufacturing
252	Valve and fittings, other than plu…	Manufacturing
253	Plumbing fixture fitting and trim …	Manufacturing
254	Ball and roller bearing manufactur…	Manufacturing
255	Small arms ammunition manufacturin…	Manufacturing
256	Ammunition, except for small arms,…	Manufacturing
257	Small arms, ordnance, and accessor…	Manufacturing
258	Fabricated pipe and pipe fitting m…	Manufacturing
259	Other fabricated metal manufacturi…	Manufacturing
260	Farm machinery and equipment manuf…	Manufacturing
261	Lawn and garden equipment manufact…	Manufacturing

262	Construction machinery manufacturi…	Manufacturing
263	Mining machinery and equipment man…	Manufacturing
264	Oil and gas field machinery and eq…	Manufacturing
265	Semiconductor machinery manufactur…	Manufacturing
266	Food product machinery manufacturi…	Manufacturing
267	Sawmill, woodworking, and paper ma…	Manufacturing
268	Printing machinery and equipment m…	Manufacturing
269	All other industrial machinery man…	Manufacturing
270	Optical instrument and lens manufa…	Manufacturing
271	Photographic and photocopying equi…	Manufacturing
272	Other commercial service industry …	Manufacturing
273	Air purification and ventilation e…	Manufacturing
274	Heating equipment (except warm air…	Manufacturing
275	Air conditioning, refrigeration, a…	Manufacturing
276	Industrial mold manufacturing	Manufacturing
277	Special tool, die, jig, and fixtur…	Manufacturing
278	Cutting tool and machine tool acce…	Manufacturing
279	Machine tool manufacturing	Manufacturing
280	Rolling mill and other metalworkin…	Manufacturing
281	Turbine and turbine generator set …	Manufacturing
282	Speed changer, industrial high-spe…	Manufacturing
283	Mechanical power transmission equi…	Manufacturing
284	Other engine equipment manufacturi…	Manufacturing
285	Pump and pumping equipment manufac…	Manufacturing
286	Air and gas compressor manufacturi…	Manufacturing
287	Elevator and moving stairway manuf…	Manufacturing
288	Conveyor and conveying equipment m…	Manufacturing
289	Overhead cranes, hoists, and monor…	Manufacturing
290	Industrial truck, trailer, and sta…	Manufacturing
291	Power-driven handtool manufacturin…	Manufacturing
292	Welding and soldering equipment ma…	Manufacturing
293	Packaging machinery manufacturing	Manufacturing
294	Industrial process furnace and ove…	Manufacturing
295	Fluid power cylinder and actuator …	Manufacturing
296	Fluid power pump and motor manufac…	Manufacturing
297	Scales, balances, and miscellaneou…	Manufacturing
298	Electronic computer manufacturing	Manufacturing
299	Computer storage device manufactur…	Manufacturing

300	Computer terminals and other compu…	Manufacturing
301	Telephone apparatus manufacturing	Manufacturing
302	Broadcast and wireless communicati…	Manufacturing
303	Other communications equipment man…	Manufacturing
304	Audio and video equipment manufact…	Manufacturing
305	Printed circuit assembly (electron…	Manufacturing
306	Bare printed circuit board manufac…	Manufacturing
307	Semiconductor and related device m…	Manufacturing
308	Capacitor, resistor, coil, transfo…	Manufacturing
309	Electronic connector manufacturing	Manufacturing
310	Other electronic component manufac…	Manufacturing
311	Electromedical and electrotherapeu…	Manufacturing
312	Search, detection, and navigation …	Manufacturing
313	Automatic environmental control ma…	Manufacturing
314	Industrial process variable instru…	Manufacturing
315	Totalizing fluid meter and countin…	Manufacturing
316	Electricity and signal testing ins…	Manufacturing
317	Analytical laboratory instrument m…	Manufacturing
318	Irradiation apparatus manufacturin…	Manufacturing
319	Watch, clock, and other measuring …	Manufacturing
320	Blank magnetic and optical recordi…	Manufacturing
321	Software and other prerecorded and…	Manufacturing
322	Electric lamp bulb and part manufa…	Manufacturing
323	Lighting fixture manufacturing	Manufacturing
324	Small electrical appliance manufac…	Manufacturing
325	Household cooking appliance manufa…	Manufacturing
326	Household refrigerator and home fr…	Manufacturing
327	Household laundry equipment manufa…	Manufacturing
328	Other major household appliance ma…	Manufacturing
329	Power, distribution, and specialty…	Manufacturing
330	Motor and generator manufacturing	Manufacturing
331	Switchgear and switchboard apparat…	Manufacturing
332	Relay and industrial control manuf…	Manufacturing
333	Storage battery manufacturing	Manufacturing
334	Primary battery manufacturing	Manufacturing
335	Fiber optic cable manufacturing	Manufacturing
336	Other communication and energy wir…	Manufacturing
337	Wiring device manufacturing	Manufacturing

338	Carbon and graphite product manufa...	Manufacturing
339	All other miscellaneous electrical...	Manufacturing
340	Automobile manufacturing	Manufacturing
341	Light truck and utility vehicle ma...	Manufacturing
342	Heavy duty truck manufacturing	Manufacturing
343	Motor vehicle body manufacturing	Manufacturing
344	Truck trailer manufacturing	Manufacturing
345	Motor home manufacturing	Manufacturing
346	Travel trailer and camper manufact...	Manufacturing
347	Motor vehicle gasoline engine and ...	Manufacturing
348	Motor vehicle electrical and elect...	Manufacturing
349	Motor vehicle transmission and pow...	Manufacturing
350	Motor vehicle seating and interior...	Manufacturing
351	Motor vehicle metal stamping	Manufacturing
352	Other motor vehicle parts manufact...	Manufacturing
353	Motor vehicle steering, suspension...	Manufacturing
354	Aircraft manufacturing	Manufacturing
355	Aircraft engine and engine parts m...	Manufacturing
356	Other aircraft parts and auxiliary...	Manufacturing
357	Guided missile and space vehicle m...	Manufacturing
358	Propulsion units and parts for spa...	Manufacturing
359	Railroad rolling stock manufacturi...	Manufacturing
360	Ship building and repairing	Manufacturing
361	Boat building	Manufacturing
362	Motorcycle, bicycle, and parts man...	Manufacturing
363	Military armored vehicle, tank, an...	Manufacturing
364	All other transportation equipment...	Manufacturing
365	Wood kitchen cabinet and counterto...	Manufacturing
366	Upholstered household furniture ma...	Manufacturing
367	Nonupholstered wood household furn...	Manufacturing
368	Other household nonupholstered fur...	Manufacturing
369	Institutional furniture manufactur...	Manufacturing
370	Wood office furniture manufacturin...	Manufacturing
371	Custom architectural woodwork and ...	Manufacturing
372	Office furniture, except wood, man...	Manufacturing
373	Showcase, partition, shelving, and...	Manufacturing
374	Mattress manufacturing	Manufacturing
375	Blind and shade manufacturing	Manufacturing

376	Surgical and medical instrument ma...	Manufacturing
377	Surgical appliance and supplies ma...	Manufacturing
378	Dental equipment and supplies manu...	Manufacturing
379	Ophthalmic goods manufacturing	Manufacturing
380	Dental laboratories	Manufacturing
381	Jewelry and silverware manufacturi...	Manufacturing
382	Sporting and athletic goods manufa...	Manufacturing
383	Doll, toy, and game manufacturing	Manufacturing
384	Office supplies (except paper) man...	Manufacturing
385	Sign manufacturing	Manufacturing
386	Gasket, packing, and sealing devic...	Manufacturing
387	Musical instrument manufacturing	Manufacturing
388	Fasteners, buttons, needles, and p...	Manufacturing
389	Broom, brush, and mop manufacturin...	Manufacturing
390	Burial casket manufacturing	Manufacturing
391	All other miscellaneous manufactur...	Manufacturing
392	Wholesale - Motor vehicle and moto...	Wholesale
393	Wholesale - Professional and comme...	Wholesale
394	Wholesale - Household appliances a...	Wholesale
395	Wholesale - Machinery, equipment, ...	Wholesale
396	Wholesale - Other durable goods me...	Wholesale
397	Wholesale - Drugs and druggists su...	Wholesale
398	Wholesale - Grocery and related pr...	Wholesale
399	Wholesale - Petroleum and petroleu...	Wholesale
400	Wholesale - Other nondurable goods...	Wholesale
401	Wholesale - Wholesale electronic m...	Wholesale
402	Retail - Motor vehicle and parts d...	Retail
403	Retail - Furniture and home furnis...	Retail
404	Retail - Electronics and appliance...	Retail
405	Retail - Building material and gar...	Retail
406	Retail - Food and beverage stores	Retail
407	Retail - Health and personal care ...	Retail
408	Retail - Gasoline stores	Retail
409	Retail - Clothing and clothing acc...	Retail
410	Retail - Sporting goods, hobby, mu...	Retail
411	Retail - General merchandise store...	Retail
412	Retail - Miscellaneous store retai...	Retail
413	Retail - Nonstore retailers	Retail

414	Air transportation	Transportation and Logistics
415	Rail transportation	Transportation and Logistics
416	Water transportation	Transportation and Logistics
417	Truck transportation	Transportation and Logistics
418	Transit and ground passenger trans…	Transportation and Logistics
419	Pipeline transportation	Natural Gas Distribution and Pipelines
420	Scenic and sightseeing transportat…	Transportation and Logistics
421	Couriers and messengers	Transportation and Logistics
422	Warehousing and storage	Transportation and Logistics
423	Newspaper publishers	Information
424	Periodical publishers	Information
425	Book publishers	Information
426	Directory, mailing list, and other…	Information
427	Greeting card publishing	Information
428	Software publishers	Information
429	Motion picture and video industrie…	Information
430	Sound recording industries	Information
431	Radio and television broadcasting	Information
432	Cable and other subscription progr…	Information
433	Wired telecommunications carriers	Information
434	Wireless telecommunications carrie…	Information
435	Satellite, telecommunications rese…	Information
436	Data processing, hosting, and rela…	Information
437	News syndicates, libraries, archiv…	Information
438	Internet publishing and broadcasti…	Information
439	Nondepository credit intermediatio…	Finance, Insurance, and Real Estate
440	Securities and commodity contracts…	Finance, Insurance, and Real Estate
441	Monetary authorities and depositor…	Finance, Insurance, and Real Estate
442	Other financial investment activit…	Finance, Insurance, and Real Estate
443	Direct life insurance carriers	Finance, Insurance, and Real Estate
444	Insurance carriers, except direct …	Finance, Insurance, and Real Estate
445	Insurance agencies, brokerages, an…	Finance, Insurance, and Real Estate
446	Funds, trusts, and other financial…	Finance, Insurance, and Real Estate
447	Other real estate	Finance, Insurance, and Real Estate
448	Tenant-occupied housing	Finance, Insurance, and Real Estate
449	Owner-occupied dwellings	Finance, Insurance, and Real Estate
450	Automotive equipment rental and le…	Finance, Insurance, and Real Estate
451	General and consumer goods rental …	Finance, Insurance, and Real Estate

452	Video tape and disc rental	Finance, Insurance, and Real Estate
453	Commercial and industrial machiner…	Finance, Insurance, and Real Estate
454	Lessors of nonfinancial intangible…	Finance, Insurance, and Real Estate
455	Legal services	Professional and Business Services
456	Accounting, tax preparation, bookk…	Professional and Business Services
457	Architectural, engineering, and re…	Professional and Business Services
458	Specialized design services	Professional and Business Services
459	Custom computer programming servic…	Professional and Business Services
460	Computer systems design services	Professional and Business Services
461	Other computer related services, i…	Professional and Business Services
462	Management consulting services	Professional and Business Services
463	Environmental and other technical …	Professional and Business Services
464	Scientific research and developmen…	Professional and Business Services
465	Advertising, public relations, and…	Professional and Business Services
466	Photographic services	Professional and Business Services
467	Veterinary services	Professional and Business Services
468	Marketing research and all other m…	Professional and Business Services
469	Management of companies and enterp…	Professional and Business Services
470	Office administrative services	Professional and Business Services
471	Facilities support services	Professional and Business Services
472	Employment services	Professional and Business Services
473	Business support services	Professional and Business Services
474	Travel arrangement and reservation…	Professional and Business Services
475	Investigation and security service…	Professional and Business Services
476	Services to buildings	Professional and Business Services
477	Landscape and horticultural servic…	Professional and Business Services
478	Other support services	Professional and Business Services
479	Waste management and remediation s…	Professional and Business Services
480	Elementary and secondary schools	Private Education
481	Junior colleges, colleges, univers…	Private Education
482	Other educational services	Private Education
483	Offices of physicians	Healthcare and Social Assistance
484	Offices of dentists	Healthcare and Social Assistance
485	Offices of other health practition…	Healthcare and Social Assistance
486	Outpatient care centers	Healthcare and Social Assistance
487	Medical and diagnostic laboratorie…	Healthcare and Social Assistance
488	Home health care services	Healthcare and Social Assistance
489	Other ambulatory health care servi…	Healthcare and Social Assistance

490	Hospitals	Healthcare and Social Assistance
491	Nursing and community care facilit...	Healthcare and Social Assistance
492	Residential mental retardation, me...	Healthcare and Social Assistance
493	Individual and family services	Healthcare and Social Assistance
494	Child day care services	Healthcare and Social Assistance
495	Community food, housing, and other...	Healthcare and Social Assistance
496	Performing arts companies	Arts, Entertainment, and Recreation
497	Commercial Sports Except Racing	Arts, Entertainment, and Recreation
498	Racing and Track Operation	Arts, Entertainment, and Recreation
499	Independent artists, writers, and ...	Arts, Entertainment, and Recreation
500	Promoters of performing arts and s...	Arts, Entertainment, and Recreation
501	Museums, historical sites, zoos, a...	Arts, Entertainment, and Recreation
502	Amusement parks and arcades	Arts, Entertainment, and Recreation
503	Gambling industries (except casino...	Arts, Entertainment, and Recreation
504	Other amusement and recreation ind...	Arts, Entertainment, and Recreation
505	Fitness and recreational sports ce...	Arts, Entertainment, and Recreation
506	Bowling centers	Arts, Entertainment, and Recreation
507	Hotels and motels, including casin...	Accommodation and Food Service
508	Other accommodations	Accommodation and Food Service
509	Full-service restaurants	Accommodation and Food Service
510	Limited-service restaurants	Accommodation and Food Service
511	All other food and drinking places	Accommodation and Food Service
512	Automotive repair and maintenance,...	Other Personal Services
513	Car washes	Other Personal Services
514	Electronic and precision equipment...	Other Personal Services
515	Commercial and industrial machiner...	Other Personal Services
516	Personal and household goods repai...	Other Personal Services
517	Personal care services	Other Personal Services
518	Death care services	Other Personal Services
519	Dry-cleaning and laundry services	Other Personal Services
520	Other personal services	Other Personal Services
521	Religious organizations	Other Personal Services
522	Grantmaking, giving, and social ad...	Other Personal Services
523	Business and professional associat...	Other Personal Services
524	Labor and civic organizations	Other Personal Services
525	Private households	Other Personal Services
526	Postal service	Federal Government
527	Federal electric utilities	Federal Government

528	Other federal government enterpris…	Federal Government
529	State government passenger transit	S&L Government (Non-Education)
530	State government electric utilitie…	S&L Government (Non-Education)
531	Other state government enterprises	S&L Government (Non-Education)
532	Local government passenger transit	S&L Government (Non-Education)
533	Local government electric utilitie…	S&L Government (Non-Education)
534	Other local government enterprises	S&L Government (Non-Education)
539	* Employment and payroll of state …	S&L Government (Education)
540	* Employment and payroll of state …	S&L Government (Non-Education)
541	* Employment and payroll of local …	S&L Government (Education)
542	* Employment and payroll of local …	S&L Government (Non-Education)
543	* Employment and payroll of federa…	Federal Government
544	* Employment and payroll of federa…	Federal Government

ATTACHMENT C

Building a Resilient Energy Future: How the Gas System Contributes to US Energy System Resilience

January 2021

Building a Resilient Energy Future:

How the Gas System Contributes to US Energy System Resilience

An American Gas Foundation Study Prepared by:

Guidehouse

Background and Methodology

This study was conducted to investigate the resilience of the US gas system and the ways in which the gas system contributes to the overall resilience of the US energy system. This work was directed to ask and answer four key questions:

- What are the characteristics of the US gas system that contribute to its resilience?
- How do those resilience characteristics allow the US gas system to contribute to the overall resilience of the US energy system?
- How can the US gas system be leveraged more effectively to strengthen the US energy system?
- What are the policy and regulatory changes that may help ensure that gas infrastructure can be maintained and developed to continue to support energy system resilience?

These questions were explored through a qualitative assessment conducted by Guidehouse, including discussions and interviews with many energy industry subject matter experts. Case studies and examples of resilience were identified as a part of these discussions. Guidehouse used these studies and examples to develop a framework for considering the resilience of the US gas system and to identify barriers and opportunities related to the gas system's role in supporting the resilience of the US energy system. The findings presented in this work identify issues that merit consideration and further exploration when developing future energy policy and regulation to ensure a resilient, reliable, and clean future energy system in all regions and jurisdictions.

Disclaimers

American Gas Foundation

Founded in 1989, the American Gas Foundation (AGF) is a 501(c)(3) organization focused on being an independent source of information research and programs on energy and environmental issues that affect public policy, with a particular emphasis on natural gas. When it comes to issues that impact public policy on energy, the AGF is committed to making sure the right questions are being asked and answered. With oversight from its board of trustees, the foundation funds independent, critical research that can be used by policy experts, government officials, the media and others to help formulate fact-based energy policies that will serve this country well in the future.

Guidehouse

Guidehouse is a leading global provider of consulting services to the public and commercial markets with broad capabilities in management, technology, and risk consulting. We help clients address their toughest challenges with a focus on markets and clients facing transformational change, technology-driven innovation and significant regulatory pressure. Across a range of advisory, consulting, outsourcing, and technology/analytics services, we help clients create scalable, innovative solutions that prepare them for future growth and success. Headquartered in Washington DC, the company has more than 7,000 professionals in more than 50 locations. Guidehouse is led by seasoned professionals with proven and diverse expertise in traditional and emerging technologies, markets and agenda-setting issues driving national and global economies. For more information, please visit: www.guidehouse.com

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Abbreviations

Abbreviation	Definition
AGF	American Gas Foundation
AWIA	America's Water Infrastructure Act
Bcf	Billion Cubic Feet
Btu	British Thermal Units
C&I	Commercial and Industrial
CAGR	Compound Annual Growth Rate
CAISO	California Independent System Operator
CHP	Combined Heat and Power
CIP	Critical Infrastructure Protection
CNG	Compressed Natural Gas
DSM	Demand Side Management
Dth	Dekatherm
EIA	US Energy Information Administration
ESR	Energy Storage Resources
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
HVAC	Heating, Ventilation, And Air Conditioning
ISO	Independent Service Operator
ISO-NE	Iso New England Inc.
LCOE	Levelized Cost of Electricity
LDC	Local Distribution Company
LNG	Liquified Natural Gas
KWh	Kilowatt-Hour
MMcf	Million Cubic Feet
MMcfd	Million Cubic Feet Per Day
MMBtu	Million British Thermal Units of Natural Gas
MW	Megawatt
MWh	Megawatt-Hour
NASA	National Aeronautics and Space Administration
NERC	North American Electric Reliability Corporation
NGV	Natural Gas Vehicle
NOAA	National Oceanic and Atmospheric Administration
NJNG	New Jersey Natural Gas
NYISO	New York Independent System Operator
OBA	Operational Balancing Agreement
PGE	Portland General Electric
psi	Pounds Per Square Inch
PSPS	Public Safety Power Shutoff
PUC	Public Utility Commission
PV	Photovoltaic
RNG	Renewable Natural Gas
RTO	Regional Transmission Organization
SCADA	Supervisory Control and Data Acquisition
T&D	Transmission and Distribution
US	United States
UTMB	University of Texas Medical Branch

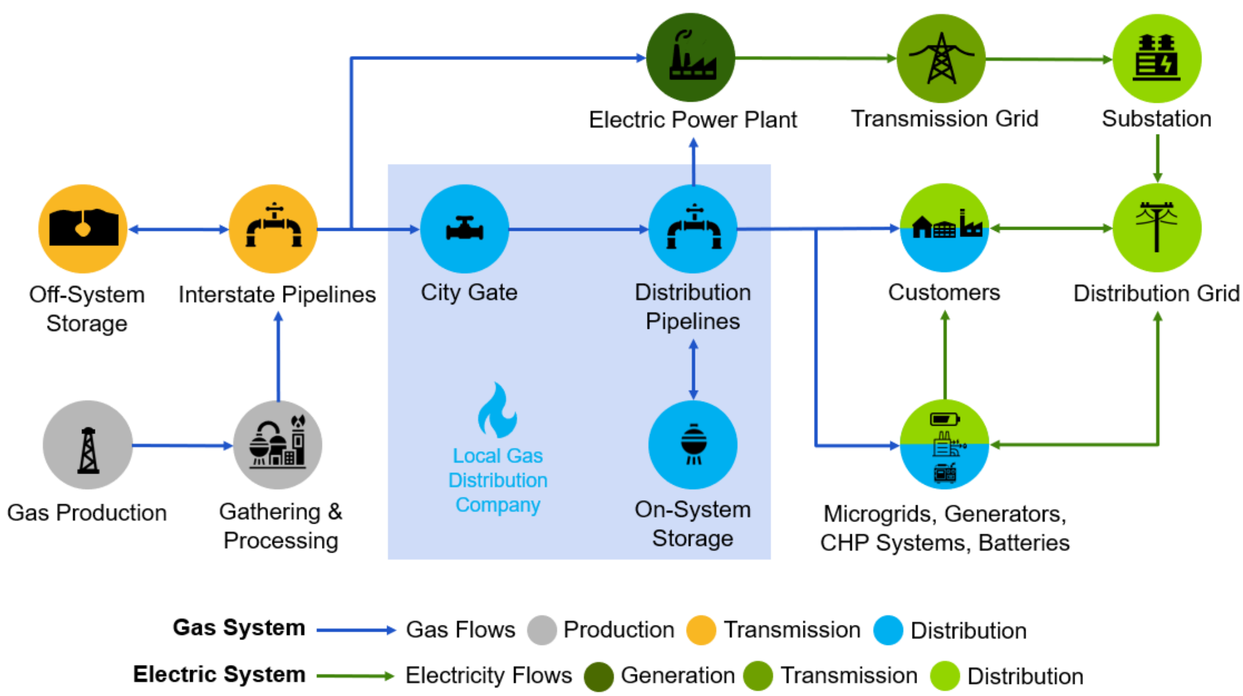
EXECUTIVE SUMMARY

A resilient energy system is essential to the operation of nearly every critical function and sector of the US economy as well as the communities that depend upon its services. Disruptions to the US energy system create widespread economic and social impacts, including losses in productivity, health and safety issues, and—in the most extreme cases—loss of life. As utilities, system operators, regulators, and policymakers deliberate the design and structure of the future energy infrastructure, they must consider the resilience of the entire energy system. As the transformation of the energy system accelerates, it is important for stakeholders to understand the increasing interdependence of gas and electric systems and their role in creating a more resilient future.

A Primer on the Energy System

An energy system is defined as the full range of components related to the production, conversion, delivery, and use of energy. Energy in the US can take many forms; this report focuses on the natural gas system, herein referred to as the gas system, and its interdependencies with the electric system (Figure 1).

Figure 1. Interdependencies Between the Gas and Electric Systems



Source: Guidehouse

What Is Resilience?

Resilience is defined as a system's ability to prevent, withstand, adapt to, and quickly recover from system damage or operational disruption. Resilience is defined in relation to a high-impact, low-likelihood events. The most common examples of these events are extreme weather events (which go beyond standard hot days or snowstorms) of a size and scale to cause significant operational disruption, system damage, and devastating societal impacts. Recent resilience events that affected the US energy system include the 2020 California heat waves, Hurricane Isaias, and the 2019 Polar Vortex.

> *Resilience and reliability are often referenced together, but they reflect critical differences in system design and operation.* ***Resilience*** *is defined as a system's ability to prevent, withstand, adapt to, and quickly recover from a high-impact, low-likelihood event such as a major disruption in a transmission pipeline. In comparison,* ***reliability*** *refers to a systems' ability to maintain energy delivery under standard operating conditions, such as the standard fluctuations in demand and supply.*

The increasing frequency and severity of climatic events amplifies the need to maintain the resilience of the US energy system. System resilience is gained through diversity and redundancy. The resilience of the US energy system is increased through evolving and holistic management of the gas and electric systems, valuing each of their unique characteristics. To ensure resilience, the energy system needs pipeline delivery infrastructure and storage capabilities meeting both short- and long-duration needs.

The nation's gas system is a critical resource for addressing resilience threats to the overall energy system. This report examines how the characteristics of the US natural gas system enable energy reliance today and opportunities to effectively use the gas system to achieve future energy resilience.

Resilience Characteristics of the Gas System

The gas system supports the overall resilience of the energy system through its inherent, physical, and operational capabilities (Figure 2) that enable it to meet the volatile demand profiles resulting from resilience events.

Figure 2. Resilience Characteristics of the Gas System

Inherent Resilience of Gas	Physical Resilience of Gas System Assets	Operational Resilience of the Gas System
A molecular form of energy storage; the natural gas molecule is an abundant energy form with long-duration and seasonal storage capabilities.	Most gas system assets are underground and shielded from major disruptions. In most cases, the system is self-reliant, reducing its exposure to disruption.	Operational flexibility is designed into the gas system within a set of system standards that ensure the system's safety and security.

• Compressibility
  ○ Storage
  ○ Linepack
• Abundance and Diversity of Supply
	• Underground infrastructure
	• Looped and Parallel T&D Network
	• Self-Reliant Gas-Fired Equipment
	• Distributed Customer Generation
	• System Storage Capacity
		• Robust Management Practices
		• Flexible Delivery
		• Demand Side Management
		• Large Customer Contract Design

Source: Guidehouse

Resilience in Action

Large, catastrophic failures of the energy system have been few and far between—the energy system has performed well, overcoming periods of high stress that have threatened its resilience. These high stress events are becoming more frequent due to the increase in the frequency and severity of extreme weather events associated with climate change. To successfully build for the future and invest in the right set of resilience solutions, it is important for stakeholders to understand how the energy system has performed under recent resilience events.

Recent climate events have revealed the US energy system's potential vulnerabilities. However, the multitude and diversity of resilience assets that already exist as part of the energy system have made the difference—facilitating energy flows to critical services and customers. As the following case studies illustrate, the resilience assets that are part of the gas system have supported the overall integrity of the energy system during these high stress periods.

2019 Polar Vortex

In 2019, the Midwest experienced record-breaking cold temperatures, which led to increased demand on the energy system to meet heating needs.

- CenterPoint Energy curtailed gas service to interruptible customers and pulled gas from every possible storage resource to maintain service to homes and businesses. In one day, CenterPoint delivered almost 50% more than a standard January day.
- On January 30, 2019, Peoples Gas, North Shore Gas, and Nicor Gas together delivered gas in an amount equivalent to more than 3.5 times

	the amount of energy that ComEd, the electric utility serving an overlapping territory has ever delivered in a single day. • The Consumers Energy's Ray Compressor Station fire on January 30 took a primary storage supply resource offline. Consumers leveraged several gas resilience characteristics (linepack, backup storage, and a highly networked gas system) to ensure that no critical, priority, or residential customer lost service.
2014 Polar Vortex	During early February 2014, a polar vortex brought extreme cold temperatures, snowfall, and high winds to Oregon. On February 6, during the system peak, NW Natural set a company record for natural gas sendouts, which still stands today. Nearly 50% of this peak demand was met by natural gas storage capacity. In combination with diligent planning and dedicated employees, this case study highlights the critical role that natural gas storage plays in meeting demand during extreme weather events.
2020 Hurricane Isaias	On August 4, 2020, Hurricane Isaias made landfall in North Carolina. It caused significant destruction as it moved north, triggering electric outages that affected more than 1 million New Jersey homes and businesses. Many customers experiencing electric outages turned on their natural gas backup generators, resulting in a massive increase in demand for New Jersey Natural Gas (NJNG). In 24 hours, NJNG experienced a 60% increase in daily demand on its gas system—the daily demand for this one day was higher than any other August day for the previous 10 years. Because of the built-in storage capacity (compressibility and on-system storage) and flexibility of the gas system, NJNG was able to ramp up service to customers with disrupted electricity supply.
2020 Heat, Drought, and Wildfires	In August 2020, California was in the middle of its hottest August on record,[1] a severe drought, and its worst wildfire season in modern history. Concurrent to increased demand on the electric system driven by increased cooling loads, California also experienced a decrease in renewable output (due to smoke from the fires)[2] and lower imports than had been anticipated by electric supply planners. To meet increased electric demand, system operators turned to gas-fired generation facilities. During the week of August 11, all of SoCalGas' system storage assets were employed to fill the gap between abnormally high electric demand and low renewable energy generation experienced in Southern California.

In all of these case studies, the gas system provided significant support to the energy system in maintaining resilience and ensuring that energy service was maintained to customers. To understand the gas system's contribution to resilience, it is important to differentiate between the pipeline infrastructure system and the natural gas molecules that flow through it. The gas pipeline system is defined as a series of physical assets that transport energy molecules from the source of production to end users, including residential, commercial, and industrial customers who use gas in their buildings and processes, and electric generators who use gas to

[1] NOAA. *National Climate Report*. August 2020.

[2] EIA. *Smoke from California Wildfires Decreases Solar Generation in CAISO*. September 30, 2020.

make electricity. Today, the gas system is used to transport mostly geologic natural gas, but it can be leveraged to transport low-carbon gases such as renewable natural gas (RNG) and potentially hydrogen in the future as utilities move to decarbonize the energy system.

The Growing Resilience Challenge

Driven by changes in the cost and availability of new technologies and increasing political and social pressure to decarbonize, our energy system is undergoing a transformation. This transformation exposes an issue of energy system resilience related to the interaction of the gas and electric systems.

> *As the percentage of electricity generation from intermittent renewable sources increases, the volume of natural gas used for electric power generation may decline; however, in responding to resilience events the necessity of the services provided by gas-fired electric generators may increase. As current compensation models for the gas system serving the power generation sector are tied to the volume of gas delivered to the facility, there becomes an increasing disconnect between the value of the services provided and associated remuneration for said services.*

To further highlight the need for energy system resilience as part of the current transformation, it is worth considering a recent review of the root cause of the California Independent System Operator (CAISO) electric outages during the August 2020 heatwave. One of the three factors identified was: "In transitioning to a reliable, clean and affordable resource mix, resource planning targets have not kept pace to lead to sufficient resources that can be relied upon to meet [electric] demand in the early evening hours. This makes balancing demand and supply more challenging. These challenges were amplified by the extreme heat storm."[3]

The current model for maintaining the resilience of our energy system was built to support a legacy view of how the energy system operates. As an example, natural gas infrastructure replacement and modernization programs were designed to enhance reliability and safety. As noted in this report they have also contributed to resilience. As the transition to the future energy system accelerates, it is important to understand how these programs complement future energy state resilience needs. The manner in which this energy system is regulated and managed is becoming outdated, and an update is necessary to maintain resilience of the evolving future energy system.

Ensuring a Resilient Future Energy System

The increasing frequency and intensity of climatic events combined with the transformation of the energy system to one increasingly powered by intermittent renewable sources establish the need for a new consideration of the resilience of the energy system. Utilities, system operators, regulators, and policymakers need to recognize that resilience will be achieved through a diverse set of integrated assets—for the foreseeable future, policies need to focus on optimizing the characteristics of both the gas and electric systems.

[3] CAISO. *Preliminary Root Cause Analysis: Mid-August 2020 Heat Storm*. 2020.

Achieving this is easier said than done. It will require a realignment of the valuation and cost recovery mechanisms that currently define the development of the US energy system:

- Energy system resilience must be defined as a measurable and observable set of metrics, similar to how reliability is considered.
- Resilience solutions must be developed considering all possible energy options and across utility jurisdictions, requiring electric, gas, and dual-fuel utilities to work together to determine optimal solutions.
- Methodologies need to be built to value resilience, such that it can be integrated into a standard cost-benefit analysis. Value should consider the avoided direct and indirect costs to the service provider, customers, and society.

The resilience of the current energy system is largely dependent on the gas system's ability to quickly respond to events and use its extensive long-duration storage resources to meet peak and seasonal demand. Ensuring future energy system resilience will require a careful assessment and recognition of the contributions provided by the gas system. Utilities, system operators, regulators, and policymakers need new frameworks to consider resilience impacts to ensure that resilience is not overlooked or jeopardized in the pursuit to achieve decarbonization goals.

1. Introduction

A resilient energy system is essential to the operation of nearly every critical function and sector of the US economy—and the need for energy system resilience is only increasing as emergency services, communications, transportation, banking, healthcare, water supply, and other critical systems become more interconnected than ever. Disruptions to the US energy system can have widespread economic and social impacts, including losses in economic productivity, health and safety issues, and—in the most extreme cases—loss of life.

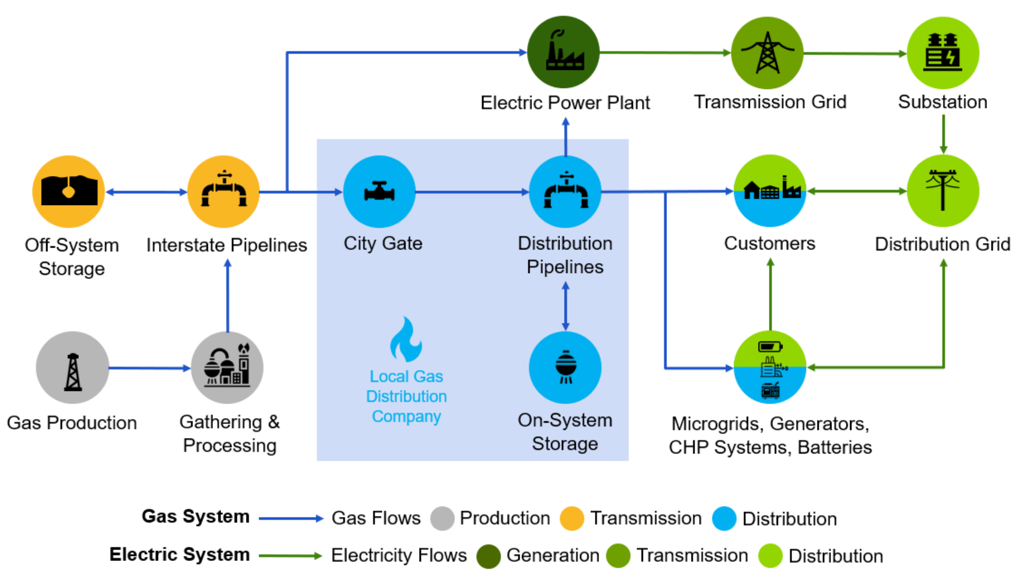
This report examines the resilience of the current gas system with a focus on the part of the system that is under the operational control of the gas local distribution company (LDC). It also examines how the gas system contributes to the resilience of the overall energy system. The work was directed to ask and answer four key questions:

1. What are the characteristics of the US gas system that contribute to its resilience?
2. How do those resilience characteristics allow the US gas system to contribute to the overall resilience of the US energy system?
3. How can the US gas system be leveraged more effectively to strengthen the US energy system?
4. What are the policy and regulatory changes needed to ensure that gas infrastructure can be maintained and developed to continue to support energy system resilience?

1.1 A Primer on the Energy System

An energy system is defined as the full range of components related to the production, conversion, delivery, and use of energy. Energy takes many forms; this report focuses on the natural gas system, herein referred to as the gas system, and its interdependencies with the electric system (Figure 1-1).

Figure 1-1. Interdependencies Between the Gas and Electric Systems

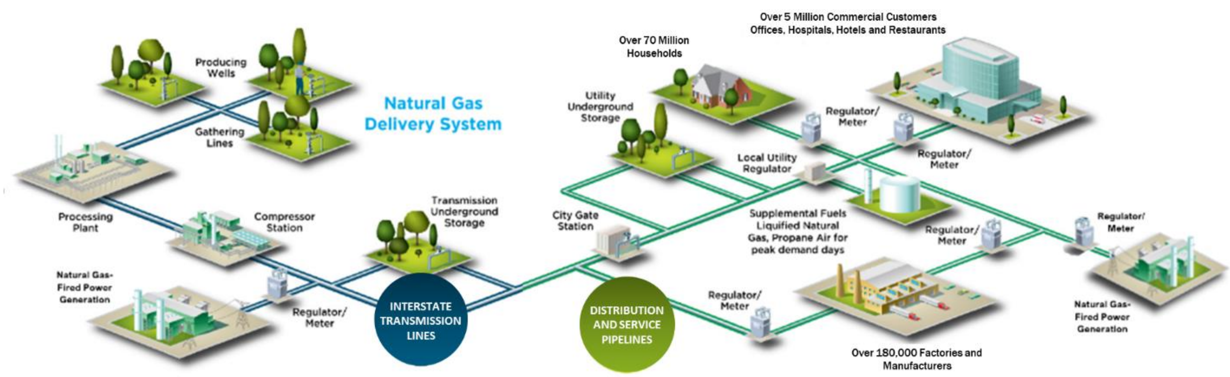


Source: Guidehouse

The gas system is the series of assets that transport energy molecules from the source of production to the site of consumption. The customers served by this system include residential, commercial, and industrial buildings and processes; gas-fired electric generation facilities; transportation fuel providers; and natural gas exporters.

Today, the gas system is used to transport mostly geologic natural gas and small amounts of renewable natural gas (RNG). In the future, the gas system can be leveraged, with only small upgrades, to transport a low carbon fuel supply including RNG, hydrogen, and synthetic methane.

Figure 1-2. Overview of the Gas System



Source: American Gas Association

The gas system can generally be divided into three sections (Appendix A presents further details):

1. **Production and Processing:** Encompasses the process of gathering the gas and treating it to remove impurities.

    - Wells extract natural gas primarily from geologic shale formations.
    - Gathering pipelines transport gas to processing facilities where impurities are removed.
    - Compressors move the gas through midstream pipelines to the connection with interstate transmission pipelines.

2. **Transmission:** Includes the network of high-pressure transmission lines that transport gas from supply basins to market demand centers and, in some cases, across local gas LDC systems.

    - Compressor stations are located approximately every 50 to 60 miles along long-haul transmission pipelines and within gas systems to regulate pressure and keep gas moving.
    - Storage assets connected to the transmission system (defined as off-system storage) exist along these transmission pipelines enabling operators to adjust flow to meet daily and seasonal demand requirements. Storage assets are either underground (i.e., depleted gas reservoirs, aquifers, or salt caverns) or aboveground (where gas is stored as LNG or CNG).

3. **Distribution:** Under the operational control of the LDC, the gas distribution system is primarily comprised of regulator stations, gas pipeline mainlines, and gas pipeline service lines that collectively reduce pressure and move gas from the transmission system to customers.

    - In many cases, gas passes through a city-gate where custody is transferred from the interstate transmission system to the LDC. At this point, gas volumes are measured, typically odorized, and pressure is reduced.
    - LDCs may have LNG, CNG, or underground storage assets on the distribution system (defined as on-system storage), allowing the LDC to maintain reliability and meet short-term demand increases.

1.2 A Primer on Resilience

Resilience is defined as a system's ability to prevent, withstand, adapt to, and quickly recover from system damage or operational disruption. The term is defined in relation to a high-impact, low-likelihood event. The most common examples of these events are extreme weather events (which go beyond standard hot days or snowstorms) of a size and scale to cause significant operation disruption, system damage, and devastating human health impacts. Common threats that test the durability of the energy system include extreme weather events (e.g., hurricanes, wildfires, and extreme heat/cold), cyberattacks (e.g., malware and cyber intrusions), and accidents.

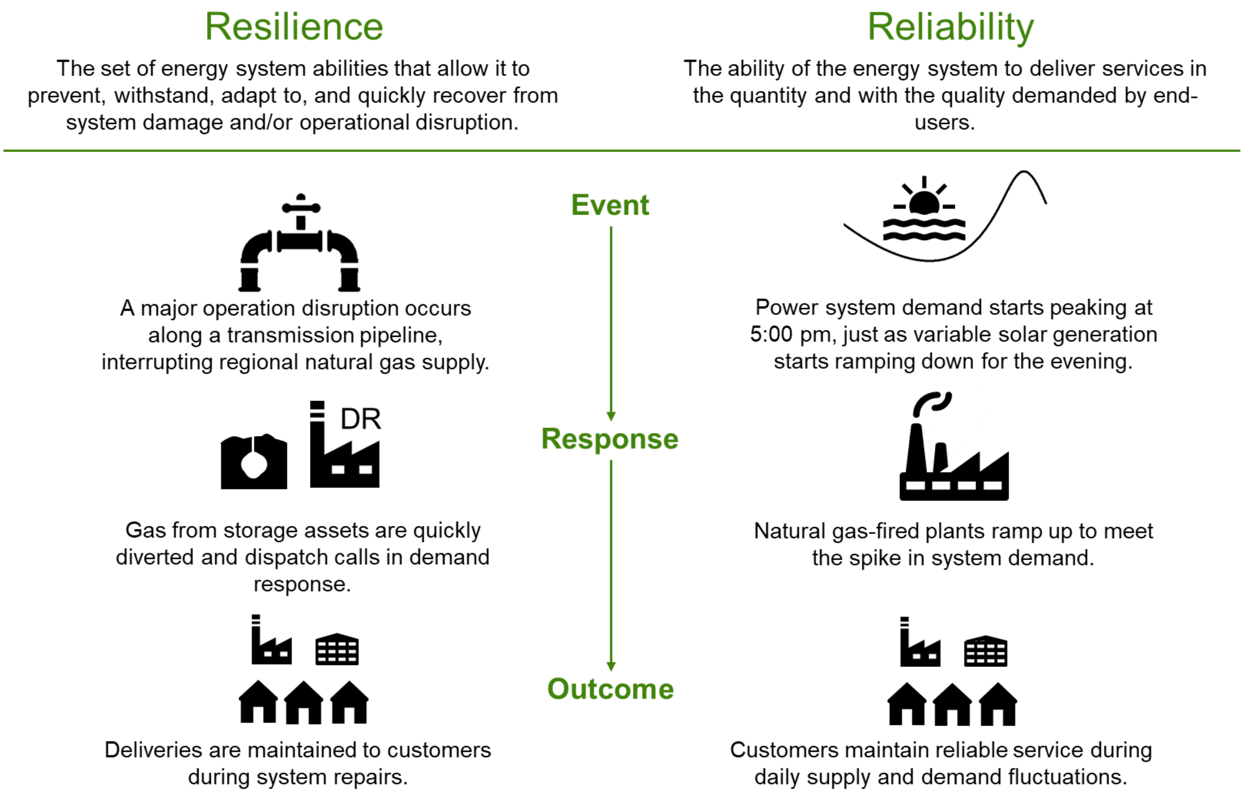
Recent examples of resilience events that affected the US energy system include the 2020 California heat waves, Hurricane Isaias, and the 2019 Polar Vortex; each of which are explored in greater detail in Section 3. Other recent resilience events that have exposed the value of the gas system in maintaining energy system delivery include the 2017 Bomb Cyclone,[4] the 2017 Californian wildfires and landslides, Hurricane Irma, and Hurricane Harvey.[5]

Resilience and reliability are often referenced in tandem, but there is a critical difference between the terms and their impact on the design and operation of energy systems. Reliability is defined in relation to a low-impact, high-likelihood event. The US energy system manages reliability daily—in the standard fluctuations in energy supply and demand. Figure 1-3 illustrates resilience and reliability events, along with typical energy system responses and associated outcomes.

[4] The Natural Gas Council; Prepared by RBN Energy. 2018. *Weather Resilience in the Natural Gas Industry: The 2017-18 Test and Results.*

[5] ICF. 2018. *Case Studies of Natural Gas Sector Resilience Following Four Climate-Related Disasters in 2017*.

Figure 1-3. Comparison of Resilience and Reliability

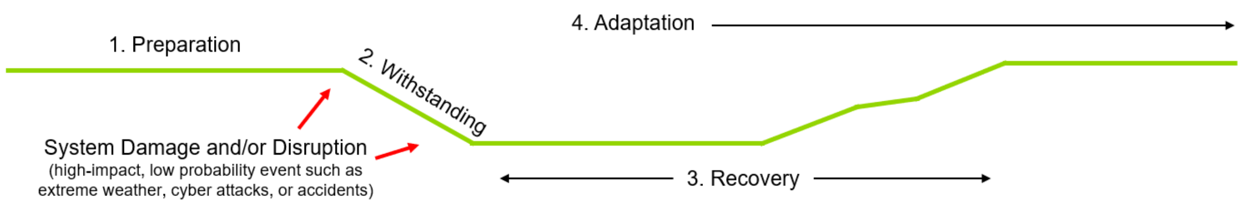


Source: Guidehouse

One way to conceptualize a resilience event is to separate it into distinct phases, where each phase is defined by a time period in relation to the event's onset. Figure 1-4. illustrates this approach with a resilience curve. Table 1-1Table 1-1. defines the four phases of this curve: preparation, withstanding, recovery, and adaptation.

The resilience curve provides a framework for understanding how an energy system's resilience can be strengthened. It is used in Section 2 to classify the resilience characteristics of the gas system.

Figure 1-4. The Energy System Resilience Curve



Source: Guidehouse

Table 1-1. Definition of the Phases of Resilience

Phase	Resilience Characteristics	Timeframe
1. Preparation	The ability to prepare for and prevent initial system disruption	Leading up to the disruption event

Phase	Resilience Characteristics	Timeframe
2. Withstanding	The ability to withstand, mitigate, and manage system disruption	During the disruption event
3. Recovery	The ability to quickly recover normal operations and repair system damage	Following the end of the disruption, until system functions are fully restored
4. Adaptation	The ability to adapt and take action to strengthen the energy system in face of future disruption events	Throughout, but especially during and following the recovery phase

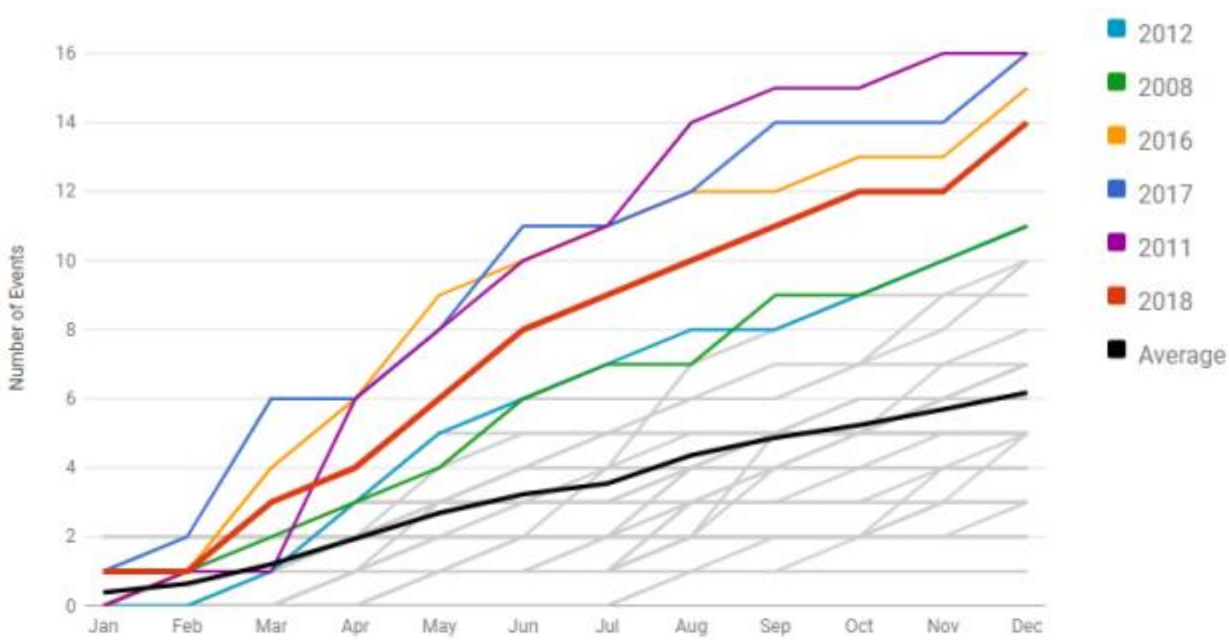
Source: Guidehouse

1.2.1 The Increasing Importance of Resilience

The increased frequency and severity of extreme weather events increasingly put the US energy system at risk. Over the last 50 years, much of the US has experienced increasingly extreme weather including prolonged periods of excessively high temperatures, heavy downpours, flooding, droughts, and severe storm activity.[6]

In the last decade, the US has experienced historic numbers of inflation-adjusted billion-dollar disasters. From 2016-2018 there were 15 billion-dollar disasters per year, up from an average of 6.2 billion-dollar disasters per year since 1980.[7] Figure 1-5. illustrates this trend and shows the cumulative inflation-adjusted billion-dollar disasters on an annual basis since 1980.

Figure 1-5. 1980-2018 Year-to-Date US Billion-Dollar Disaster Event Frequency (CPI-Adjusted, Events Statistics are Added According to the End Date)



Source: NOAA, 2018's Billion Dollar-Disasters in Context

[6] NOAA. 2014. *Fourth National Climate Assessment*.
[7] NOAA. 2019. *2018's Billion Dollar Disasters in Context*.

To further highlight the importance of placing focus on the resilience of the energy system, consider California in August 2020. California was in the middle of its hottest August (record warmest in 126 years),[8] a severe drought, and its worst wildfire season in modern history. These weather events resulted in increased demand on the electric system, driven by increased cooling load. Concurrently, the state was experiencing a decrease in the anticipated electricity supply from hydroelectricity imports and solar electric generation due to smoke from the wildfires.[9] The coincidence of these events resulted in a significant gap between electricity demand and supply on the California system that led to rolling blackouts on August 14 and 15.[10]

As explored in Case Study 3*,* in Section 3, because the gas system filled a considerable portion of the gap between abnormally high electric demand and low renewable energy generation, Southern California avoided catastrophic failure.

The increasing frequency and severity of climate events amplify the need to maintain and strengthen the resilience of the US energy system. The energy system needs redundancy and storage capabilities to respond to dramatic shifts in supply and demand quickly.

1.3 An Orientation to this Report

The remaining content in this report is separated into five major sections.

- *Section 2 The Resilience of the Gas System* describes the various inherent, physical, and operational characteristics of the gas system that contribute to the resilience of the US energy system.
- *Section 3 Proving It: Resilience in Action* details five case studies that demonstrate how gas distribution companies across the country have demonstrated gas system resilience through real-world examples.
- *Section 4 Current Regulatory, Policy, and Market Structure* summarizes how current regulatory, policy, and market structures create challenges for building gas resilience assets.
- *Section 5 Ensuring A Resilient Future* explores how decarbonization-driven changes to the electric system may present challenges for future resilience and lessons learned from other economic sectors.
- *Section 6 Conclusions* presents a call to action for how the findings in this report can be used and their implications for policymakers and regulators.

[8] NOAA. National Climate Report – August 2020. https://www.ncdc.noaa.gov/sotc/national/202008
[9] EIA. *Smoke from California Wildfires Decreases Solar Generation in CAISO.* September 30, 2020. https://www.eia.gov/todayinenergy/detail.php?id=45336
[10] California Independent System Operator. 2020. *Preliminary Root Cause Analysis.*

2. The Resilience of the Gas System

This section explores the fundamental resilience characteristics of the gas value chain and describes how it provides resilience services to customers. These characteristics are detailed further in Section 3 in case studies that demonstrate gas system resilience through real-world examples.

2.1 Fundamental Resilience Characteristics of the Gas System

Guidehouse examines the fundamental inherent, physical, and operational characteristics of the gas system in relation to their contribution along the resilience curve phases, i.e. how they help the gas system prepare for, withstand, recover from, and adapt to a resilience event. Table 2-1 outlines the key questions considered in evaluating these characteristics within the gas value chain.

Table 2-1. Key Questions Used to Identify Resilience Characteristics

Resilience Phase	Key Identifying Questions
1. Preparation	• Does it help the system prepare for or prevent threats? • Does it reduce the physical exposure of system infrastructure to the threat?
2. Withstanding	• Does it help minimize system impacts or sensitivity to potential disruptions? • Does it help prevent the occurrence of cascading failures? • Does it help the system maintain functioning if a disruption occurs?
3. Recovery	• Does it assist in restoring or repairing lost functionality?
4. Adaptation	• Does it help the system adjust to changing climate or operating conditions? • Does it facilitate learning and resilience investments to prevent future threats?

Source: Guidehouse

Gas system characteristics that contribute to energy system resilience are highlighted in Figure 2-1. they are also discussed in greater detail throughout this section.

Figure 2-1. Resilience Characteristics of the Gas System

Inherent Resilience of Gas

A molecular form of energy storage; the natural gas molecule is an abundant energy form with long-duration and seasonal storage capabilities.

- Compressibility
  - Storage
  - Linepack
- Abundance and Diversity of Supply

Physical Resilience of Gas System Assets

Most gas system assets are underground and shielded from major disruptions. In most cases, the system is self-reliant, reducing its exposure to disruption.

- Underground infrastructure
- Looped and Parallel T&D Network
- Self-Reliant Gas-Fired Equipment
- Distributed Customer Generation
- System Storage Capacity

Operational Resilience of the Gas System

Operational flexibility is designed into the gas system within a set of system standards that ensure the system's safety and security.

- Robust Management Practices
- Flexible Delivery
- Demand Side Management
- Large Customer Contract Design

Source: Guidehouse

2.2 Inherent Characteristics of Gas Resilience

As a molecular form of energy storage, natural gas molecules have several inherent characteristics that contribute to the resilience of the gas system. Chief among these characteristics is its compressibility, which allows additional volumes of gas to be packed into the pipeline or under- and above-ground storage. Natural gas supply is also abundant and geographically diverse, allowing it to meet current energy needs even in the event of a supply chain disruption. The inherent characteristics also hold true for low carbon forms of gas supply which may replace natural gas in the future gas system. Table 2-2 summarizes the inherent characteristics of gas resilience, which are also discussed further in this section.

Table 2-2. Inherent Resilience Across the Phases of Resilience

<table>
<tr><th></th><th colspan="4">Resilience Phases</th></tr>
<tr><th>Characteristic</th><th>Preparation</th><th>Withstanding</th><th>Recovery</th><th>Adaptation</th></tr>
<tr><td>Compressibility
Storage
Linepack</td><td colspan="2">Reduces sensitivity to disruptions</td><td>Buffers against cascading failures</td><td></td></tr>
<tr><td>Abundance and Diversity of Supply</td><td></td><td colspan="2">Maintains production in the event of a regionally isolated supply-side disruption</td><td>Low carbon options for a future energy system</td></tr>
</table>

Source: Guidehouse

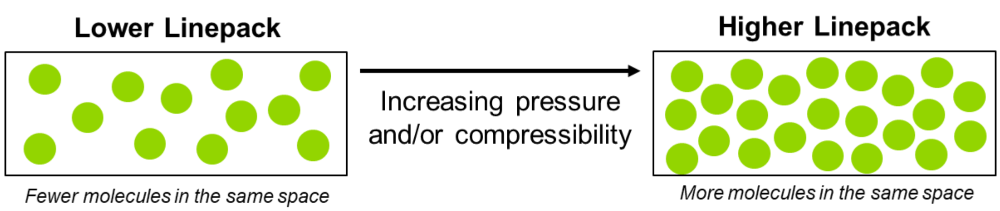
2.2.1 Compressibility

Natural gas is made up of inherently stable and compressible molecules, making it a desirable energy storage carrier and pipeline system buffer.

- **Storage** – Long-duration gas storage is frequently used to meet seasonal demand patterns and can be used as a complement to the electric system in meeting demand during low-likelihood, high-impact resilience events. Natural gas can be compressed and stored underground in geological formations (e.g., in depleted gas reservoirs, aquifers, or salt caverns) or aboveground in tanks (as LNG or CNG). As LNG, the volume of natural gas is about 600 times smaller than its gaseous form at atmospheric pressure; whereas, as CNG, it is 100 times smaller.

- **Linepack** – Excess natural gas molecules, i.e. more than what would be needed to meet customer demand can be compressed and stored within pipelines, acting as a buffer to minimize the impact of short-term hourly supply and demand fluctuations on the gas system (Figure 2-2).[11] Gas system operators, including LDCs, can control the amount of linepack in the pipes, allowing them to meet rapid, intraday changes in demand even if upstream supply is insufficient.

Figure 2-2. Linepack and Compressibility of Gas



Source: Guidehouse

Figure 2-2 provides a clear example of how linepack and storage can be used in tandem to prevent and mitigate the effects of a major gas system disruption. These characteristics are different from the electricity grid where disruptions can immediately impact all connected gas systems and increase the risk of cascading failures. Electric supply and demand must be balanced across the electric system near instantaneously and electricity can only be stored in specified storage assets, such as batteries.

2.2.2 Abundance and Diversity of Supply

Natural gas is supplied from a variety of sources across North America, including:

- **Conventional production:** Currently, natural gas is primarily produced from shale plays and formations; it is also produced in smaller quantities from conventional gas reservoirs, tight sands, carbonates, and coal-bed methane. Figure 2-3 highlights the geographic diversity of US shale plays and formations. Additionally, an evaluation by the Potential Gas Committee at year-end 2018 indicated that the US possesses a technically recoverable resource base of natural gas of nearly 3,400 trillion cubic feet (Tcf).[12] The US Energy Information Administration additionally reported that US proved

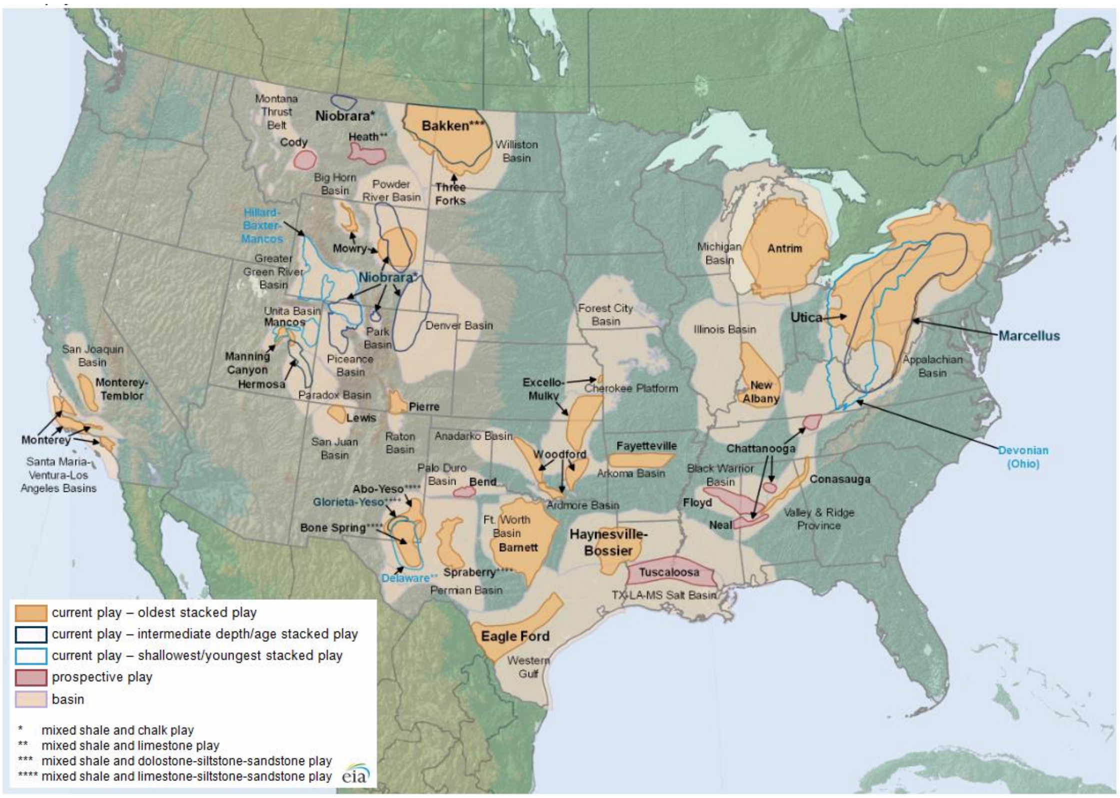
[11] Natural Gas Council. 2019. *Natural Gas: Reliable and Resilient.*

[12] Potential Gas Committee. 2019. *Potential Supply of Natural Gas in the United States.* Accessed November 2020.

reserves stood at 504.5 Tcf as of 2018. The combination of these supplies suggests a future gas supply resource enough to meet over 100 years of consumption at current levels.[13]

This abundance and diversity of natural gas supply ensures that natural gas can continue to meet customer demand even during regionally isolated supply-side disruptions such as a major storm event. For example, limited supply interruptions during recent hurricanes demonstrates the value of shifting natural gas production from the Gulf of Mexico to geographically diverse shale plays and formations.

Figure 2-3. US Shale Plays and Formations



Source: US Energy Information Administration

- **Low Carbon Production:** The abundance and diversity of resources transportable through the gas system will increase as RNG and hydrogen become increasingly commercially viable. Though it is only a small portion of current US gas supply, RNG supply is growing dramatically--produced from a variety of waste feedstocks from the sewage, agriculture, food, and forestry sectors, as detailed in Appendix B. Hydrogen is projected to serve a larger portion of future US gas demand, but it is earlier in the process of developing commercial viability in the US, though it is already flowing through the pipes in Europe as discussed in Appendix B.

[13] Natural Resources Canada. 2020. *Natural Gas Facts.* Accessed October 2020.

- **Pipeline Imports:** Natural gas is also imported via pipeline from Canada, and from elsewhere as LNG. These are critical supply sources during peak periods and lend to greater gas system flexibility.

2.3 Physical Characteristics of Gas System Resilience

The gas system's physical characteristics lend themselves to providing stability to the energy system. Most pipeline infrastructure is underground and looped, creating flexibility in a delivery system that is shielded from many major disruptive events. Much of the gas delivery system also runs on its own supply, making it self-reliant. The ability to store gas further strengthens the self-reliant attributes of the gas system, enabling it to respond to disruption or an extreme peak caused by unprecedented demand or upstream disruption. Table 2-3 summarizes these physical characteristics of gas resilience, which this section also discusses.

Table 2-3. Physical Resilience Across the Phases of Resilience

<table>
<tr><th></th><th colspan="4">Resilience Phases</th></tr>
<tr><th>Characteristic</th><th>Preparation</th><th>Withstanding</th><th>Recovery</th><th>Adaptation</th></tr>
<tr><td>Underground Infrastructure</td><td>Reduces exposure to threat</td><td>Minimizes impact of potential disruptions</td><td></td><td></td></tr>
<tr><td>Looped and Parallel T&D Network</td><td></td><td colspan="2">Improves deliverability in the event of regionally isolated gas network disruption</td><td></td></tr>
<tr><td>Self-Reliant Gas-Fired Equipment</td><td></td><td></td><td>Maintains gas delivery during an electric grid outage</td><td></td></tr>
<tr><td>Distributed Customer Generation</td><td></td><td>Reduces electric grid demand during extreme weather event</td><td colspan="2">Enables customer flexibility in the event of an electric grid disruption outage</td></tr>
<tr><td>System Storage Capacity</td><td>Prepares system for expected demand increase</td><td>Balances supply and demand fluctuations</td><td>Improves deliverability during disruption</td><td>Facilitates supply-side diversity (renewable integration)</td></tr>
</table>

Source: Guidehouse

2.3.1 Underground Infrastructure

Natural gas is one of the few energy resources predominantly delivered to customers by pipeline. In contrast, other common energy forms, such as electricity, are mostly delivered by aboveground wires. Although each delivery method has advantages, the underground gas delivery system has significantly reduced exposure to disruptive events from extreme weather such as hurricanes and snowstorms. Because of this, significant weather events rarely disrupt localized segments of the network and damage is typically limited to aboveground facilities where pipeline assets may be exposed.[14]

[14] EIA. *Natural Gas Explained: Natural Gas Pipelines*. Accessed October 2020.

2.3.2 Looped and Parallel Transmission and Distribution Network

The gas system is extensively interconnected with multiple pathways for rerouting deliveries. This interconnectivity enables the sourcing of natural gas from various production centers across the country. Additionally, distribution mains are typically interconnected in multiple grid patterns with strategically located shut-off valves. These valves allow operators the ability to isolate segments of a gas system, which minimizes customer service disruptions. To reinforce the resilience of gas delivery, the valves are paired with on-system storage and mobile pipeline solutions.

> *A 2019 study by the Rhodium Group on natural gas system reliability indicated that, "the US natural gas system typically deals with a handful of disruptions every month that last a day or more. Despite these disruptions, deliverability to end-use sectors, including electric power generators, is rarely impacted because of the redundancy built into the system."[15] While this study focused on reliability, it highlights the system redundancy that is available to respond to higher-impact resilience events.*

In addition to the interconnectivity of the gas system design, pipeline capacity is often increased by installing two or more parallel pipelines in the same right-of-way (called pipeline loops), making it possible to shut off one loop while keeping the other in service. Further, in the event of one or more equipment failures, gas pipelines can continue to operate at pressures necessary to maintain deliveries to pipeline customers, at least outside the affected segment. Considering customer impacts of individual equipment failures in the design of gas pipelines and facilities to determine where investment in redundant infrastructure is prudent, is part of the gas utility risk management process.

2.3.3 Self-Reliant Gas-Fired Equipment

Much of the equipment used on the gas system, including compressors, dehydration equipment, pressure regulators, and heaters, are usually powered by the gas that flows through the pipes they serve. Powering equipment by the gas in the system limits the gas system's reliance on external supply chains. If gas continues to flow through the pipes—which has demonstrated to be a resilient supply chain itself—the gas system will continue to operate, and gas will flow to customers.

In some cases, the pursuit of decarbonization goals has resulted in the replacement of gas compressors with electric compressors. While electric compressors are not yet widespread, their use does reduce this resilient aspect of gas system operation.

2.3.4 Distributed Customer Generation

The US Department of Energy has documented how combined-heat and power (CHP) systems serve as a resilience solution, with specific case studies on how CHP has provided resilience for critical facilities during major weather events, giving them the flexibility to produce thermal energy and electricity onsite.[16] Example 1 highlights one such case study. CHP systems at

[15] Rhodium Group. 2019. *Natural Gas Supply Disruption: An Unlikely Threat to Electric Reliability*.

[16] US Department of Energy. 2018. "CHP Technology Fact Sheet Series."

these facilities are largely dependent on the resilience of the US gas system and its ability to continue delivering natural gas during resilience events.

At the end of 2019, there were 3,186 commercial and industrial (C&I) CHP sites fueled by natural gas with a total capacity of 58,140 MW.[17] This distributed generation is equivalent to over 5% of total US electric power generation capacity. Distributed CHP systems exemplify how the gas system supports the resilience of end-use customers by giving them alternative options to generate heat and electricity in the case of unplanned energy system disruptions. The costs and inconvenience of a power outage can be substantial, including losses in productivity, product, revenue, and customers. Gas-fired standby generators also provide a resilience benefit by helping to avoid the impact of a power outage. This benefit is discussed further in Case Study 5.

Example 1. CHP and Distributed Generation Support Critical Infrastructure During Extreme Weather Events[18]

Hurricanes. In 2008, Hurricane Ike flooded over 1 million square feet of the University of Texas Medical Branch (UTMB) in Galveston, Texas. The hurricane interrupted utility services and resulted in the complete loss of UTMB's underground steam distribution system. Learning from this experience, the UTMB installed a 15 MW CHP facility (11 MW fueled by natural gas) to improve resilience and allow for an immediate return of hospital and clinical operations.

This resilience solution was tested during Hurricane Harvey in 2017 when the campus lost power. In circumstances that would have otherwise caused a blackout, the CHP system continued to operate during and after the storm, allowing the hospital to maintain regular operations. As a co-benefit, the CHP system saves UTMB approximately $2 million per year in utility costs and reduces campus emissions by 16,476 tons of CO_2 per year.

2.3.5 Gas System Storage Capacity

The ability to store large quantities of energy supply is a fundamental strength of the gas system allowing it to respond to, prepare for, withstand, and recover from disruption. In addition, gas storage facilities offer further geographic supply diversity to the gas system, as these storage assets can often maintain supply if disruptions are experienced on the system. Gas system storage capacity is built as a result of long-term planning in response to forecasted seasonal and peak demand. Gas system storage can be classified by where it is connected to the gas value chain.

- **On-System Storage:** This storage is operated and controlled by the LDC, allowing it to respond quickly to peak demand requirements and emergency situations. On-system storage is often aboveground, and in some situations underground. One advantage of on-system storage is that it can be sited at specific locations on the gas distribution system to best provide a resilience benefit (both supply and pressure support) in the event of an upstream disruption. This benefit is exemplified in Case Study 4.

[17] U.S. Department of Energy. 2019. *U.S. Department of Energy Combined Heat and Power Installation Database*. Accessed October 2020.

[18] Southcentral CHP Technical Assistance Partnerships. 2019. *Project Profile: University of Texas Medical Branch 15 MW CHP System*. Accessed October 2020.

- **Off-System Storage:** This storage is connected to a transmission line and is not directly tied to an LDC's distribution system. In most cases, off-system storage is underground, which makes it resilient to many climate-driven disruptions.
- **Mobile Storage:** Stored as LNG or CNG, natural gas can be moved via truck to serve short duration needs such as providing temporary supply for emergency response, pipeline maintenance, and construction and peak shaving.

The gas system's storage capacity is critical to its ability to respond to disruption. For example, the gas system storage capacity allows the gas system to respond to extreme heat and cold events when large amounts of gas are drawn in a short period. In addition, system storage provides a supply buffer allowing the LDC vital time to respond to unplanned delivery constraints in the pipeline and distribution network, resulting from gas system disruptions. The capacity of US gas storage and the associated value of that storage is further explored in Example Box 2.

Example 2. The Value of Gas Storage

In 2019, the US consumed approximately 31 trillion cubic feet of natural gas. If this natural gas was consumed in the same amount every day, the US would consume approximately 85 Bcf per day (Bcfd). But natural gas usage is seasonal – in January 2019, the US consumed nearly 110 Bcfd on average compared to approximately 71 Bcfd in June.[19]

With seasonal fluctuations in use and additional fluctuations in daily consumption, gas storage plays a vital role in balancing supply and demand. The US has nearly 400 underground storage facilities in the lower 48 states with a total storage capacity of more than 4,000 Bcf. In 2019, approximately 2,300 Bcf of natural gas supply was delivered from storage facilities, roughly the energy equivalent of 700 million megawatt-hours (MWh).[20]

NW Natural operates the Mist underground storage facility in Oregon. Its 20.1 Bcf of gas storage capacity is equivalent to 6 million MWh. Installing a battery of equivalent size on the electric system would cost approximately $2 trillion in 2020 dollars.[21]

Storage assets are additionally well positioned to support future state resilience demands and are capable of using low carbon commodities. These long-lived assets can be re-missioned to meet evolving energy system resilience requirements.

2.4 Operational Characteristics of Gas System Resilience

The industry has several operational tools at its disposal to prepare for, withstand, recover from, and adapt to disruptions. The gas system has robust management practices for the flows of gas on the system and there are several opportunities to provide flexibility in delivery and to manage demand. Table 2-4 summarizes these operational characteristics of gas resilience, which are also discussed further in this section.

[19] https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm

[20] https://www.eia.gov/naturalgas/ngqs/#?report=RP7&year1=2019&year2=2019&company=Name

[21] https://www.nrel.gov/docs/fy19osti/73222.pdf

Table 2-4. Operational Resilience Across the Phases of Resilience

<table>
<tr><th></th><th colspan="4">Resilience Phases</th></tr>
<tr><th>Characteristic</th><th>Preparation</th><th>Withstanding</th><th>Recovery</th><th>Adaptation</th></tr>
<tr><td>Robust Management Practices</td><td colspan="4">Activates backup resources, prevents and mitigates cyber threats, improves response to disruptions, facilitates learning from unanticipated disruptions</td></tr>
<tr><td>Flexible Delivery</td><td></td><td></td><td>Improves gas deliverability during extreme conditions</td><td></td></tr>
<tr><td>Demand-side management and energy efficiency</td><td colspan="2">Reduces demand before and during extreme events</td><td>Provides gas system operators demand-side control during disruptions</td><td></td></tr>
<tr><td>Large customer contract design</td><td></td><td colspan="2">Flexibility to curtail non-firm transport customers</td><td></td></tr>
</table>

Source: Guidehouse

2.4.1 Robust Management Practices

The gas industry maintains safe and resilient operations using a variety of tools including long-term resource planning, emergency response planning, standard operating procedures, and incident-response protocols. The industry also has a well-established Mutual Aid Program that allows utilities to provide and receive aid from other utility members in the event of disaster or emergency situations.[22] Pipeline operators are trained per the US Department of Transportation's pipeline safety requirements.

Gas utilities also follow robust cybersecurity protocols,[23] and align their cybersecurity programs to several key frameworks and standards including the NIST Cybersecurity Framework, the ISA/IEC 62443 Series of Standards on Industrial Automation and Control Systems (IACS) Security, ISO 27000, NIST 800-82, the TSA Pipeline Security Guidelines, and API Standard 1164.[24] Gas assets are also designed with manual override and manual backups in case of cyber disruption.

2.4.2 Flexible Delivery

In addition to on-system storage, some LDCs use mobile pipeline solutions. These non-pipeline solutions are frequently LNG or CNG tanker trucks that deliver needed supplies directly to an injection point on the distribution system in the event of a gas system disruption. The ability to deliver through multiple pathways is a valuable characteristic of the gas system.

[22] American Public Gas Association. *Mutual Aid Program.* Accessed November 2020.
[23] Oil and Natural Gas Sector Coordinating Council; Natural Gas Council. 2018. *Defense-in-Depth: Cyber Security in the Oil and Natural Gas Industry.*
[24] Natural Gas Council. 2019. *Natural Gas: Reliable and Resilient.*

Example 3. Operational Management Helps Prepare for and Withstand Extreme Weather Events

During the January 2019 polar vortex, a severe wave of cold weather swept over the midwestern US, bringing temperatures to well below -20°F in several states. Minnesota experienced its lowest air temperatures since 1996, reaching a low of -56°F and wind chills below -60°F in some areas.[25]

Leading up to the event, CenterPoint Energy used gas system modeling and SCADA to predict how its gas system would react to the extreme cold temperatures. Based on this data, CenterPoint Energy deployed two CNG trailers to strategic locations where additional supply might be needed and placed field crews on standby across the state. Engineering, operations, and gas control were in constant communication, as is standard practice for most cold-weather events. Though CenterPoint Energy's gas system met demand during record temperatures without the need of the CNG trailers, this example highlights how gas LDCs use robust management practices to prepare for and withstand extreme weather events.[26] CenterPoint Energy's response to the 2019 polar vortex is highlighted further in Case Study 1 in Section 3.

2.4.3 Demand Side Management and Energy Efficiency

Gas system operators have a robust toolbox to safely, effectively, and efficiently accommodate demand. Many gas utilities offer demand side management (DSM) and energy efficiency programs to support their customers in managing their gas consumption, while some are also piloting demand response (DR) programs that can include controllable devices such as connected thermostats. Implementation of these programs frequently results in resilience benefits. For example:

- Residential customers participating in weatherization programs to reduce their energy use associated with heating and cooling will enjoy a home that is more efficient and can better maintain comfortable indoor temperatures. These residents will be better able to shelter in place if they experience disruptions in their energy supply.
- Participation in energy efficiency programs in general will result in more efficient energy usage and lower annual spend on energy.
- DSM and DR programs offer grid operators the opportunity to improve the efficiency and stability of the power system by reducing the severity of demand spikes. Although these programs are often developed to increase reliability, they also offer significant resilience benefits in allowing grid operators the ability to adjust the demand side of the equation when a significant disruption is experienced.

2.4.4 Large Customer Contract Design

Gas system operators contract with large-volume customers in a way that mitigates potential physical constraints around deliverability. Large-volume customers voluntarily enter into either a firm contract (i.e., they are contractually guaranteed an agreed amount of supply, regardless of potential gas system capacity constraint issues) or an interruptible contract (i.e., their service can be interrupted if the gas system is experiencing capacity constraint issues) with the gas system. This means that gas system operators have the flexibility to contractually curtail delivery to large-volume interruptible customers in the event of disruption, a form of demand response, which is one reason why the gas system rarely experiences service disruptions.

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[25] Minnesota Department of Natural Resources. 2019. *Cold Outbreak: January 27-31, 2019.* Accessed October 2020.
[26] CenterPoint Energy, Interview. October 2020.

The definitions of firm and interruptible customers may need further clarification as the gas system sees more large-volume users with dramatic swings in their maximum and minimum usage throughout a day. However, the gas system's ability to contract differently with users that use the gas system differently is a resilience characteristic that must be recognized.

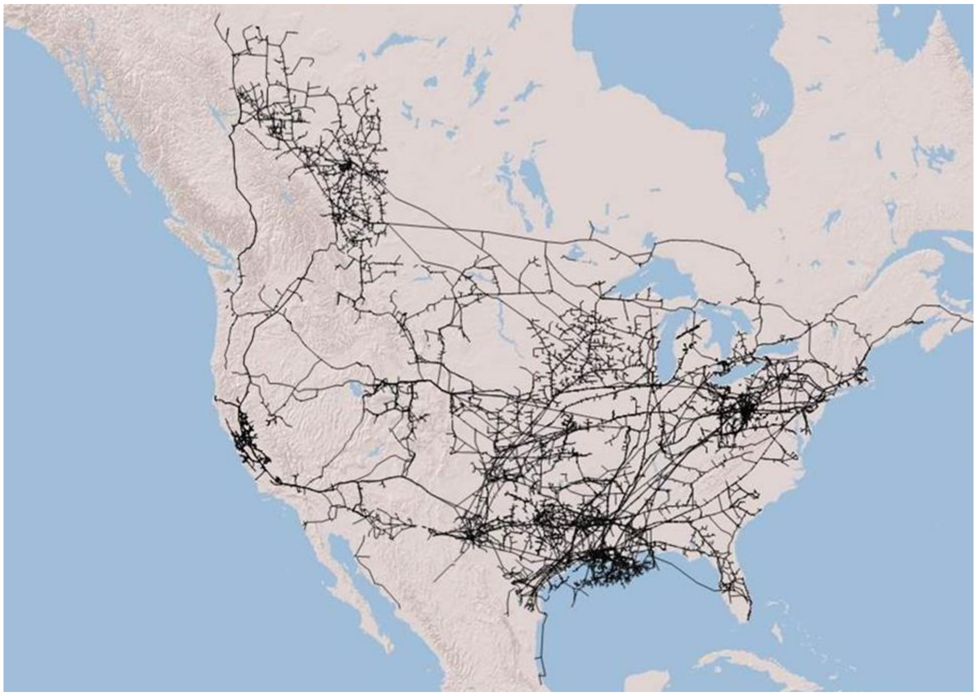
2.5 Resilience Limitations

The overall US gas system's network contributes to its stability but the degree of interconnectedness on the network can vary across LDCs based on the following two primary factors:

- The availability of operational capacity on upstream pipelines and storage
- The physical location of the LDC service territory in relation to pipelines and storage facilities

As Figure 2-4 illustrates, some US regions have more access to the transmission system than others. For example, the Pacific Northwest is supplied by fewer pipelines compared to the Upper Midwest and the Gulf Coast. A gas utility or geographic region with limited access to multiple transmission pipelines will need to leverage other resilience solutions to develop transportation and supply diversity, such as storage.

Figure 2-4. Major North American Natural Gas Pipelines



Source: S&P Global Market Intelligence

3. Proving It: Resilience in Action

The inherent, physical, and operational capabilities of the gas system—from receipt of supply from the upstream pipelines to the ability to provide short-notice storage withdrawal and injection rates—enable it to meet the volatile demand profiles resulting from resilience events. This section includes six case studies that exemplify how the gas system contributes to the resilience of the US energy system.

It is a testimony to the preparedness and true resilience of the industry that there are so few case studies of extra measures ever needing to be taken to respond to periods of extraordinarily high demand.

Polar Vortex (January 2019)

- In Case Study 1, the use of a diverse mix of gas resilience assets (upstream pipelines, storage, LNG and propane storage, flexible non-pipeline assets) allowed the gas system to meet record peak demand resulting from extreme cold temperatures.

- In Case Study 2, the integral role the gas system plays in supporting the space heating needs of customers in colder climates is explored. The case study also demonstrates that during a peak event, the gas system currently delivers substantially more energy than the electric system is built to deliver.

- In Case Study 3, the resilience attributes of the gas system were put to the test when a fire caused a failure on a critical gas compression and storage facility. Despite losing almost one-third of its on-system storage, the gas utility withstood this failure during a period of peak demand without involuntary loss to a single residential customer.

Polar Vortex (February 2014)

- In Case Study 4, the role of natural gas storage, both underground and aboveground, as a critical resilience solution to meet record gas demand is demonstrated.

Hurricane Isaias (August 2020)

- In Case Study 5, natural gas was used as a backup power source to ensure essential power functions could continue to be met for residential and commercial customers in the middle of a hurricane.

Heat, Drought, and Wildfires (August 2020)

- Case Study 6, storage capacity resources were used to meet the supply needs of gas-fired generation plants when the California electric system experienced high demand from a record-breaking heatwave and unplanned reductions in other sources of generation.

Case Study 1: Meeting Record Peak Demand (Minnesota)

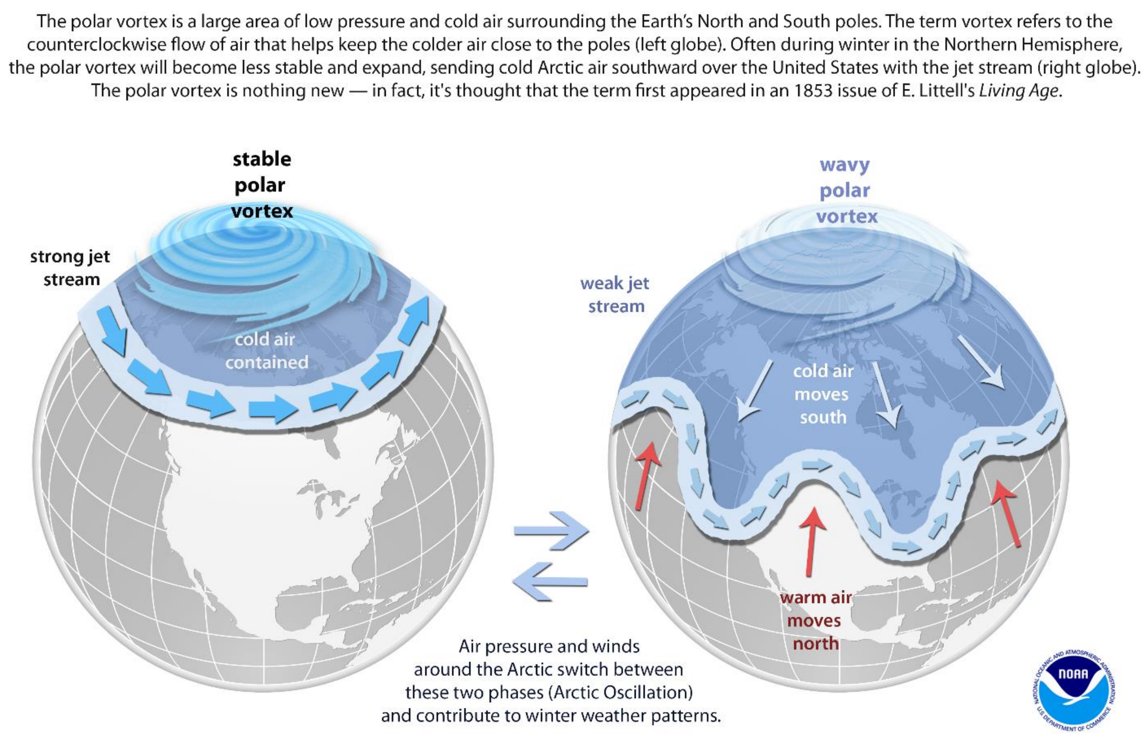
Key Finding

CenterPoint Energy used a diverse mix of gas resilience assets (upstream pipelines, storage, LNG and propane storage, flexible non-pipeline assets) to meet record peak demand resulting from extreme cold temperatures across the Midwest.

Introduction

The first three case studies pertain to the January 2019 Polar Vortex, when a weakened jet stream resulted in the coldest temperatures in over 20 years to most affected regions across the US and Canada (Figure 3-1). The event resulted in at least 22 deaths and grounded around 2,700 flights across the Midwest and Northeast.

Figure 3-1. The Science Behind the Polar Vortex



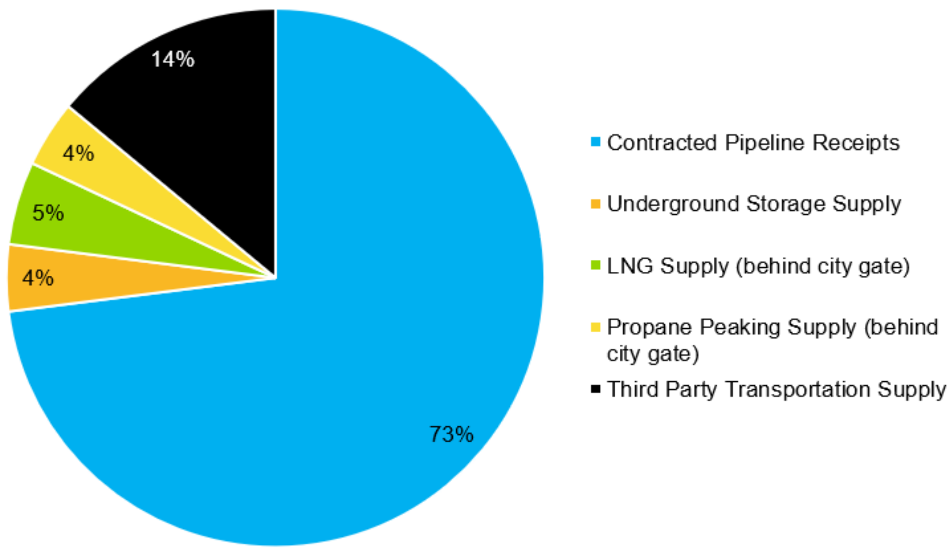
Source: National Oceanic and Atmospheric Administration

Overview

During the January 2019 Polar Vortex, in Minneapolis, Minnesota, the average temperature was -19°F from January 29 to 30. The coldest hour occurred at 6:00 a.m. on January 30 when the temperature was -30°F (before wind chill). On these days, CenterPoint Energy (which serves 870,000 customers in the greater Minneapolis region) experienced record daily delivery of natural gas of 1,495,000 Dth on January 29 and 1,448,000 Dth on January 30. This compares to 1,000,000 Dth of daily sendout in a typical January day, or a 49% and 44.8% increase over average for January 29 and 30, respectively.

Because the demand for gas was so high on CenterPoint's gas system on January 29 and 30, interruptible customers and interruptible transportation service deliveries were curtailed to maintain distribution system integrity for firm demand customers. Even after curtailing these customers, CenterPoint Energy needed to pull gas supply from every available source, as Figure 3-2 illustrates. Approximately 13% of the gas delivered to CenterPoint's customers in Minneapolis on these very cold days was supplied by storage, including LNG and propane assets, which played a critical role in providing additional supply and pressure to maintain gas system integrity.

Figure 3-2. Gas Supply by Source, CenterPoint Energy, Minneapolis, Minnesota, January 29-30, 2020



Source: Guidehouse, CenterPoint Energy

Like many gas utilities, this planning consists of a thorough review of gas supply plans and monitoring of distribution system performance in addition to heightened staffing to be prepared for quick response to issues.

Table 3-1. CenterPoint Energy Actions to Maintain Gas System Viability During the 2019 Polar Vortex

Phase of Resilience	CenterPoint Actions to Maintain Gas System Deliveries in Response to the 2019 Polar Vortex
1. Preparation	• Daily review of supply plans by gas supply, gas control, peak shaving, and engineering. • Daily preparation and execution of cold weather engineering plans. • Daily staging of operations technicians in critical locations to monitor/react. • Daily staffing of engineering personnel in the cold weather ops center to support system operations and gas control. • Dispatch Center: Extra staff added to coordinate with field operations. • Field operations: Implementation of cold-weather operating plans.

Phase of Resilience	CenterPoint Actions to Maintain Gas System Deliveries in Response to the 2019 Polar Vortex
	• The areas requiring CNG trailer deployment were identified using system modeling and SCADA to help predict how the system would react during the cold event. • Two CNG trailers were deployed and on standby. These flexible non-pipeline solutions provided just in time delivery to reinforce system operations
2. Withstanding	• Aside from the CNG locations, CenterPoint Energy positioned several field crews at different locations throughout its service territory on standby to be responsive should an unexpected issue arise. In addition, critical groups, including engineering, operations, and gas control were in constant communication to monitor the system.
3. Recovery	• The system did not incur any damage or major disruptions, so there was no recovery phase for this event.
4. Adaptation	• System reinforcements were identified and later completed for the areas where CNG trailer were deployed. • Regular review of distribution system performance as cold weather occurs. • Adjustments are made if needed and as possible. • Testing and operation of stations and equipment.

Source: Guidehouse, CenterPoint Energy

Conclusion

CenterPoint Energy's use of a diverse mix of gas system resilience assets to meet record peak demand from a climate event exemplifies how the gas system contributes to the energy system's overall stability. Upstream pipelines, storage, LNG and propane storage, and flexible non-pipeline assets were deployed for addressing unplanned or unforeseen events within the integrated energy system.

Case Study 2: The Role of Natural Gas (Illinois)

Key Finding

During the 2019 Polar Vortex, Nicor Gas, Peoples Gas, and North Shores Gas' daily distributions of natural gas (7.32 Bcf) were equivalent to 90GW of electricity—more than 3.5 times the amount of electricity that ComEd, the electric utility serving a similar territory has delivered in a single day. The gas system provides value in the volume of energy that can be delivered during peak events, which will require significant infrastructure buildout to be replaced.

Introduction

During the record-breaking cold weather that occurred January 30 and 31, 2019, Nicor Gas, the LDC serving 2.2 million customers in Illinois delivered more than 4.88 Bcf of natural gas per day. This is more than double the natural gas delivered on a typical day in January day. In terms of energy delivery, this amount of gas, an average of 0.20 Bcf per hour, compares to approximately 61 GW of electricity.[27] This is the single largest delivery of natural gas in the company's history—surpassing previous records set when 4.5 Bcf was delivered between January 6 and 7, 2014.

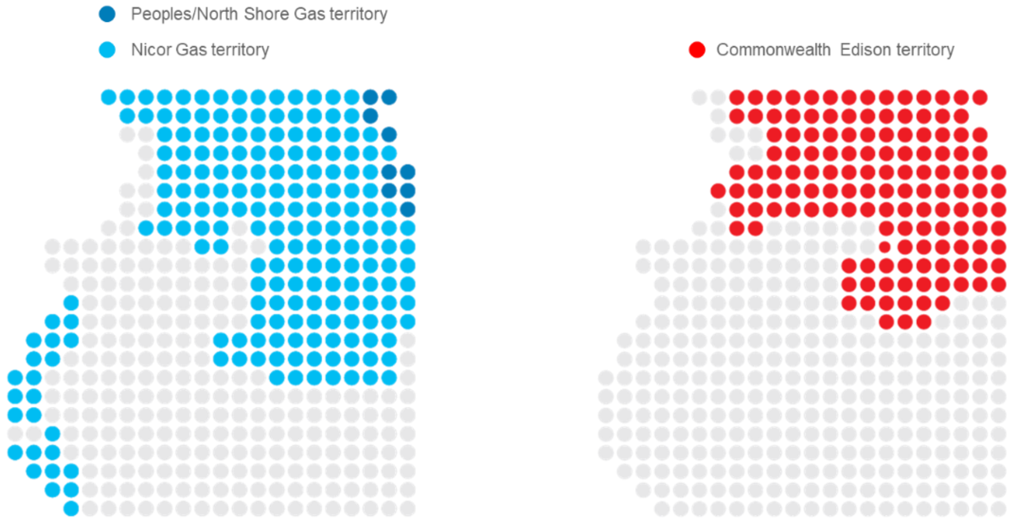
Nicor Gas employees worked around-the-clock during this cold weather to monitor the distribution system to ensure the safe performance and reliability of the infrastructure. More than 7,000 customer calls were received at the customer contact center and field operations responded to nearly 1,500 emergency calls for service during the two days. There were no major service outages during the weather event.

Overview

On January 30, 2019, together Peoples Gas, North Shore Gas, and Nicor Gas distributed more than 7.32 Bcf of natural gas—this is comparable to approximately 90 GW of electricity and represents more than 3.5 times the amount of electricity that ComEd, the electric utility serving northern Illinois, has ever delivered in single day (Figure 3-3). Even on a typical day, the Nicor Gas system alone delivers an amount of energy that is approximately equal to the maximum amount of energy that ComEd has ever delivered on a single day. The historic peak delivery day for the ComEd system is 24.8 GW, which occurred on July 20, 2011.

[27] Calculation: 4.88bcf/24 hours*10^9 scf* 1,020 Btu/scf * 1 kWh/3,412 Btu = 60, 785, 463 kW (or 60.8 GW)

Figure 3-3. Energy Distribution by Northern Illinois Utility



Utility	Peak demand (gas)	Peak demand (electricity)
Peoples Gas/North Shore Gas	~2.44 Bcf	~30.4 GW*
Nicor Gas	4.88 Bcf	~60.8 GW*
ComEd Historic Peak Demand on July 20,2011		24.8 GW

Source: Nicor Gas Company

There are several takeaways for regulators and policymakers that emerge from this case study. First off, it is critical to understand the implications of electrification on infrastructure investment, not just for a typical day, but for a peak event.

The gas system plays an integral role in supporting the space heating needs of customers in colder climates. Moreover, in the wintertime, space heating requirements typically begin to increase in the early morning and late afternoon hours; these are times when intermittent, renewable resources may not be available. Without the gas system, battery storage with significant duration and capacity capabilities would be required to bridge the gap between generation from intermittent, renewable resources and heating demands.

The gas system provides value in the volume of energy that can be delivered during peak events, which will require significant infrastructure buildout to be replaced.

Case Study 3: Ray Compressor Station Fire (Michigan)

Key Finding

Despite the loss of availability of the largest storage facility on its gas system, Consumers Energy was able to serve all of its customers without any involuntary disruption during a period of record cold temperature and peak demand.

Introduction

As the CenterPoint Energy and Nicor Gas case studies demonstrate, the Polar Vortex of January 2019 placed enormous stress on the gas delivery system under record-setting conditions. When extreme cold weather hit Michigan from January 29 to February 1, Consumers Energy was prepared to fulfill demand utilizing gas storage and pipeline supply as the primary supply sources. Consumers Energy had 61.9 Bcf of working natural gas inventory, above its target of 61.4 Bcf during a typical winter.

Gas storage fields play a critical role in enabling Consumers Energy to serve its customers during times of peak demand. They are used to meet demand at various levels:

- **Baseload demand:** Along with pipeline supply, baseload storage fields run daily during the winter to meet a foundation level of demand.
- **Intermediate demand:** Intermediate storage fields run during longer periods of higher demand.
- **Peak demand:** Peaker (and needle peaker) storage fields run during the extreme hours and days when demand changes quickly, typically in the early morning when customers start their day and their gas appliances.

Consumers Energy operates 15 storage fields with a total working capacity of 149 Bcf. The largest, the Ray Peaker field, has a capacity of 47.52 Bcf, or almost one-third of Consumers Energy's working storage capacity. The Ray facility is a combination compressor station and adjacent storage field.

Consumers Energy planned to fulfill demand during this cold period using baseload production storage fields, Ray field, and pipeline supply as the primary sources. Its other peaker fields were in reserve to support gas system packing and address any potential interruptions in pipeline supply, baseload fields, and compressor stations.

Incident

At approximately 10:30 a.m. on January 30, a fire occurred at the Ray Natural Gas Compressor Station. The fire reduced the amount of natural gas Consumers Energy could deliver to customers from underground storage in the Ray field near the compressor station. The damage to its largest storage and delivery system, which occurred during historically high natural gas demand due to cold temperatures, prompted Consumers Energy to take steps to ensure gas deliveries to its customers continued uninterrupted.

Response

Consumers used a variety of inherent, physical, and operational resilience characteristics to respond to the supply disruption during historic cold temperatures. Throughout the entire event, not a single critical, priority, or residential customer lost service involuntarily.

Table 3-2. Summary of Resilience Characteristics Used by Consumers Energy

Date	Key Resilience Characteristics
2018	• Consumers Energy held a training exercise in 2018 with a scenario involving a fire at Ray Compressor Station. This prepared employees by providing an opportunity to **rehearse emergency response** roles and responsibilities.
January 24, 2019	• In preparation of forecasted extreme cold temperatures, notice was given to **interruptible customers** that interruptible service would not be available beginning January 25.
January 30, 2019	• System **linepack** provides immediate buffer to sudden loss of storage supply from approximately 10:30 a.m. to 8:00 p.m. • At 10:45 a.m., Consumers Energy leveraged its **networked system** by calling five major interconnected pipelines that agreed to provide supply on a best effort basis. • **Peaker storage fields** were dispatched and began flowing at approximately 11 a.m., reducing sole reliance on linepack. • At 1 p.m., Consumers Energy began requests for **voluntary load reductions** from 104 of its highest volume customers. • Procurement of additional supply. • Formal **curtailment** for large transport customers began at approximately 3 p.m. • At 8 p.m., Consumers Energy worked with the governor to use the **Emergency Broadcast system** to ask residential customers for voluntary natural gas reductions. • Near 11 p.m., some of the Ray facilities supply capabilities were returned to service.
January 31, 2019	• Continued curtailment enables additional 40,000 Mcf of demand reduction.
February 1, 2019	• Announcement of cessation of curtailment at 8:22 a.m.

Source: Guidehouse, Consumers Energy

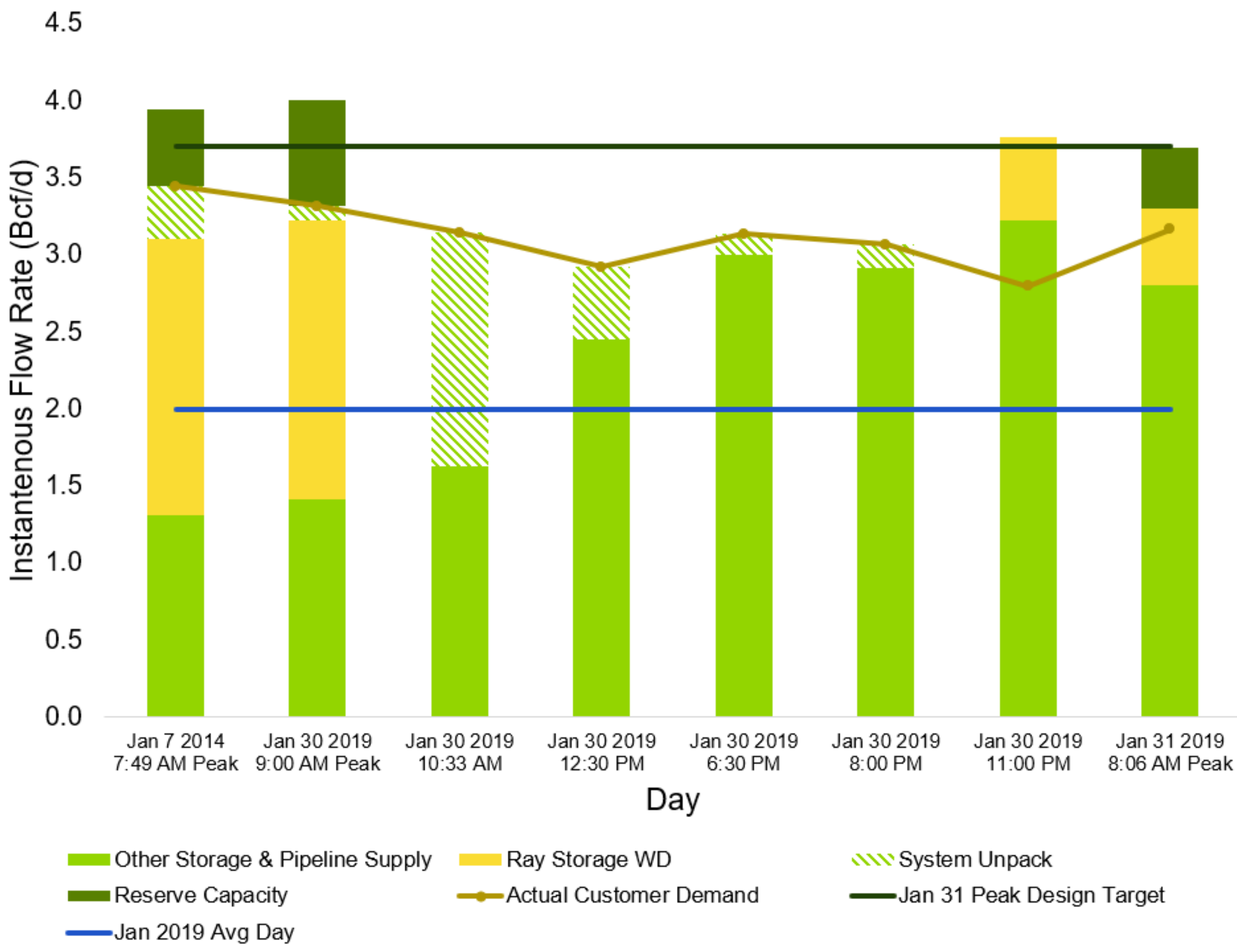
As Figure 3-4 shows, the loss of gas supply from the Ray facility caused the gas system to begin unpacking at an excessive rate. Unpacking means the amount of gas and the available pressure in the pipeline are decreasing and it occurs when the rate of total supply is lower than the rate of total delivery to customers. Figure 3-4 depicts the status of supply, demand, rate of gas system unpack,[28] and Ray Field flow on January 7, prior to the event. It also shows several points including the peak hour of January 30 at 11:00 p.m. and the peak hour of the next day at

[28] Unpack refers to the system's use of linepack.

8:06 a.m. on January 31. The loss of Ray and the rate at which the pipeline system was unpacking caused key gas system pressures to decline at excessive rates.

Shortly after the fire-gate alarm was received, Consumers Energy Gas Control adjusted the storage field rate orders to dispatch all peaking storage fields at maximum flow rates including those fields on standby. The peaking storage fields added approximately 975 MMcf/day of supply. The dispatch of the peaking fields maximized the total amount of storage supply delivered and reduced the gas system unpack rate. In addition, additional supplies provided by neighboring pipelines helped to mitigate the loss of supply from the Ray storage field (shown in light green in Figure 3-4 and the corresponding reduction in gas system unpack is shown in light green cross-hatching).

Figure 3-4. Consumers Energy System Supply, Demand, and Reserve Capacity January 30-31, 2019



Source: Guidehouse, Consumers Energy

Consumers Energy took several steps to mitigate the impact of the loss of access to the Ray storage field. These steps included requests for voluntary reductions in gas usage of all customers. Consumers Energy also implemented an Operational Flow Order (OFO) for the first time in its history for natural gas transportation customers, which required those customers to match their natural gas deliveries to Consumers Energy's system to their usages. When the requests for voluntary actions and the OFO did not result in the reductions in gas usage necessary to stabilize the gas system, Consumers Energy implemented a mandatory curtailment of gas deliveries to large business customers for the first time in its history, which required a reduction in their natural gas usage down to minimum loads required to protect equipment. In cooperation with Governor Whitmer, Consumers Energy also requested all-natural gas customers in Michigan to conserve natural gas by dialing down their thermostats. On Thursday, January 31, Consumers Energy announced that the appeal for assistance would end at 12:00 a.m. on February 1 for all customers—commercial, industrial, and residential.

Conclusion

This Ray Compressor fire event and the subsequent recovery by Consumers Energy is a unique story of the resilience characteristics of the gas system. Despite the loss of availability of the largest storage facility, not a single critical, priority, or residential customer lost service involuntarily during a peak of record cold temperature throughout the region, due to the fire-gate event.

Consumers Energy was able to withstand, recover, and adapt due to diligent advanced preparation and execution of its emergency response plan during the event. Access to physical assets is a key contributor to resilience. The ability to use alternate flow paths within facilities enables the recovery of the gas system and the return to customer's ability to use gas normally. Consumers Energy's ability to use existing storage assets as a first response demonstrates this opportunity. However, practice, preparation, and planning are also critical contributors to resilience, as demonstrated by Consumers Energy's response.

The company's capabilities in emergency management, including the use of an Incident Command System (ICS), enabled it to respond rapidly and organize into an ICS structure that included both a command post and an Emergency Operations Center (EOC). The well-defined chain of command, incident objectives, and tactics allowed for effective internal coordination of resources. It also enabled fast, complete, and transparent engagement with the MPSC, State Emergency Operations Center (SEOC), and the Governor's office throughout the event. Furthermore, it provided an organized approach to protect life and safety, to stabilize the incident, and to protect property and the environment.

Case Study 4: The Role of Winter Gas Storage (Oregon)

Key Finding

Storage assets, in combination with diligent planning and dedicated employees, play a critical role in providing natural gas during periods of critical demand in response to cold weather events.

Introduction

Northwest Natural (NW Natural) provides service to approximately 2.5 million people in Oregon and southwest Washington state (Figure 3-5). The Portland metro area represents the largest portion of NW Natural's customer demand, and its weather is characterized by a temperate oceanic climate with warm, dry summers and mildly cold, wet winters.

Figure 3-5. NW Natural Service Territory

Source: NW Natural

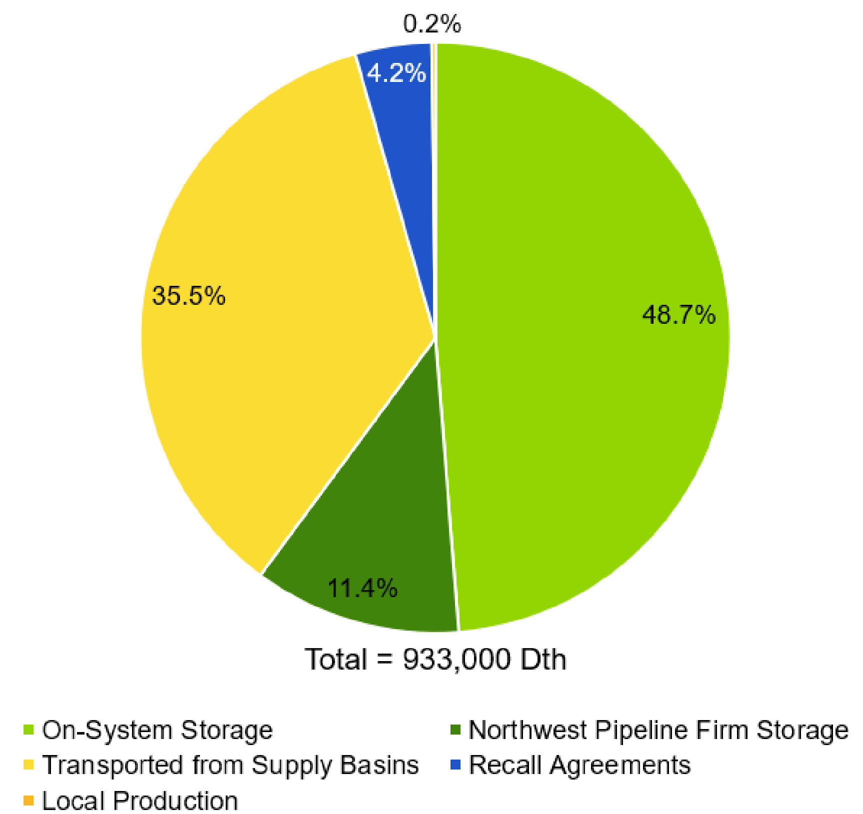
NW Natural personnel oversee the safe operation of 14,000 miles of transmission and distribution mains, monitor deliveries at over 40 interconnections with the upstream interstate pipeline system, and coordinate the usage of three on-system storage facilities (one underground storage and two LNG plants) along with off-system storage. The Gas Control department, as an example, is responsible for forecasting near-term loads, monitoring pressures, flows and other conditions using telemetry data fed from field devices, electronically controlling certain field equipment, and determining the usage rates of the on-system storage facilities, all on a 24/7 basis.

NW Natural's resource planning is designed to meet customer needs during an extreme cold weather event, occurring in late January or early February. One such event occurred in February 2014.

The Winter of 2013-2014

Extreme cold weather in early December 2013 set the stage for a challenging winter. Storage facilities are usually full at the start of the heating season, and large quantities can be withdrawn to meet sudden surges in sales. Stored gas is akin to a large battery, representing energy reserves that can be held indefinitely while remaining ready at short notice to satisfy customer requirements. On extremely cold days, stored gas is expected to supply approximately 60% of NW Natural's firm sales load (Figure 3-6). On February 6, 2014, total sendout set a record of 900,000 Dth that still stands today. NW Natural's prior record was 890,000 Dth, set on January 5, 2004. Stored gas played a critical role in meeting this record demand and provided nearly 50% of total sendout on this day.

Figure 3-6. NW Natural Peak Day Firm Resources, as of Nov 1, 2013



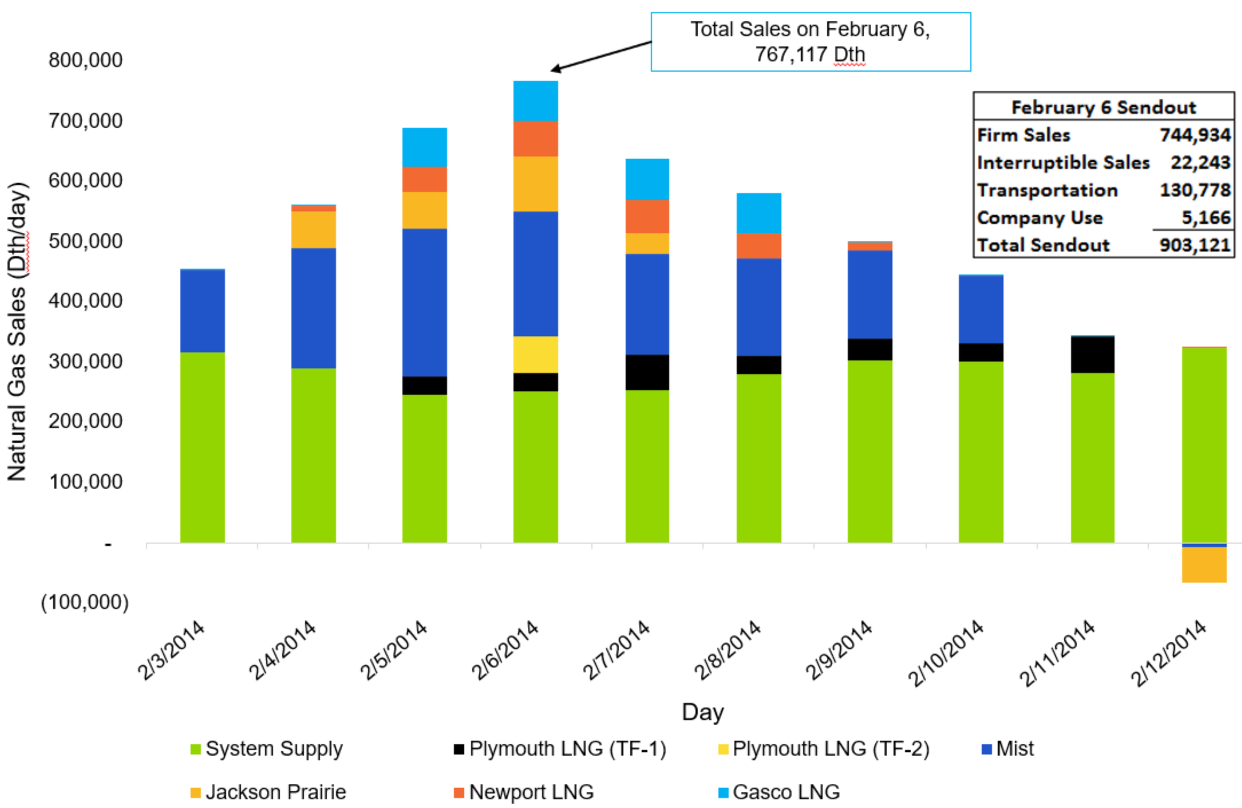
Source: Guidehouse, NW Natural

Stored gas, once withdrawn, will likely not be replenished until the following summer. Also, deliverability from storage can decrease as volumes are withdrawn, so the decision was made in December to procure additional supplies in the market in order to conserve the usage of storage gas. This planning proved extremely valuable later in the season.

The Peak Event

During early February, cold temperatures were accompanied by about a foot of snow and freezing rain. While this winter storm episode was not quite as long and cold as that experienced in the December event, a very high wind chill factor increased customer demand by an estimated 10 percent over what would be normal based on cold temperatures alone. During this period, storage resources were relied on heavily for both economic and delivery resilience reasons, growing to over 50% of daily sales requirements and then subsiding within a week's time (storage resources are all non-green colors in Figure 3-7).

Figure 3-7. NW Natural Resource Utilization During Cold Weather Event, February 3-12, 2014



Source: Guidehouse, NW Natural

Similar to the December event, in February, NW Natural had employees monitoring and controlling gas pressures at specific locations in North and East Vancouver (Washington), Southwest Salem, and South Eugene. The company also rotated two CNG trailers to support the morning peak demand in an isolated area of Northwest Vancouver, Washington.

Employee dedication and resourcefulness during the peak event included field crews manually controlling pressure regulators to ensure the maximum amount of gas could move through the pipes, storage operators working around the clock to maximize gas availability, Gas Control working with the upstream interstate pipeline to increase gate station throughput, and service technicians responding to four times the normal volume of customer calls.

Snow and ice took their toll on the gas system, requiring exceptional emergency response. For example, trees burdened by snow fell onto buildings and gas meters, some members of the public lost control of their vehicles and ran into gas meters, and parts of buildings collapsed onto gas meters. Some employees had to carry chainsaws in order to remove fallen trees blocking their way.

Aftermath

Several parts of NW Natural's service territory had seen significant customer growth over the prior two decades, and experience gained during the 2013-14 winter confirmed the need to reinforce the supply system to these areas. Besides reports of a handful of isolated customer outages, the only significant distribution system problem was in Clark County, Washington, where service had to be curtailed to four industrial interruptible customers during the morning burn hours.

Curtailment of service to interruptible sales and interruptible transportation customers is an explicit feature of NW Natural's resource planning. During the winter of 2013-14, interruptible customer curtailments were minimal because supplies were abundant, capacity was relatively unconstrained, and the gas system showed its resilience during weather conditions that tested but did not reach the extremes of the company's resource planning standards.

Case Study 5: Hurricane Response (New Jersey)

Key Finding

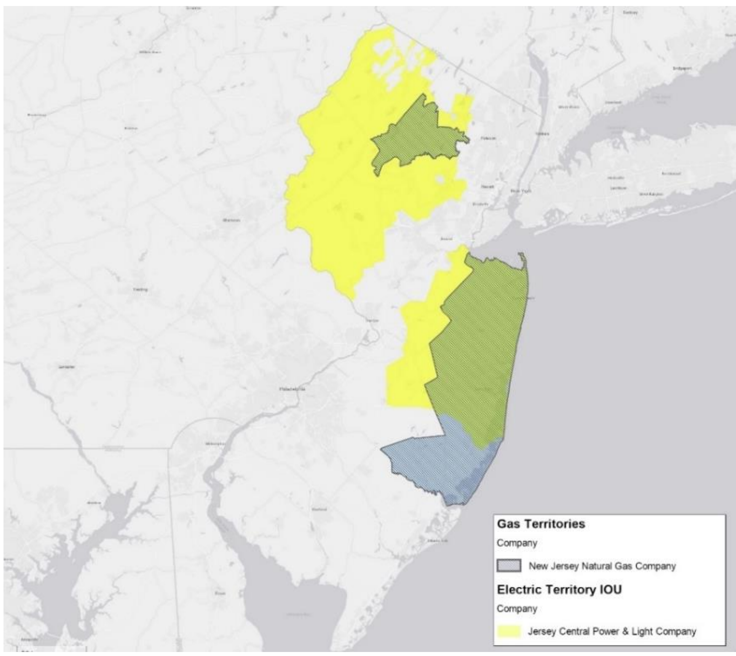
New Jersey Natural Gas Company delivered significantly more gas than normal in a short period to support backup electric power generation for residential and commercial customers in the middle of a hurricane.

Introduction

Hurricane Isaias was a destructive Category 1 hurricane that caused extensive damage across the Caribbean and the US East Coast. The hurricane made landfall near Ocean Isle Beach, North Carolina on August 4, 2020. Shortly after landfall, it was downgraded to a tropical storm.[29] When the storm reached the New Jersey region, it caused extensive damage and caused power outages that affected more than 1 million New Jersey homes and businesses.

Of the +1 million homes and businesses that lost power during Hurricane Isais, 788,000 were customers of Jersey Central Power & Light. As these customers saw an outage in their electric service, many turned to their natural gas generators to meet their power needs. New Jersey Natural Gas (NJNG), the gas provider for much of Jersey Central Power & Light's territory (Figure 3-8), experienced a massive increase in gas demand as these gas generators turned on.

Figure 3-8. Service Territories for Jersey Central Power & Light Company and New Jersey Natural Gas Company



Source: S&P Global Market Intelligence

[29] Len Melisurgo. August 8, 2020. "As bad as Tropical Storm Isaias was, here's why experts say N.J. dodged a bullet." *NJ.com*.

Overview

On Monday, August 3, the day before Hurricane Isaias caused the power outages, NJNG supplied 54,000 Dth to customers. On Tuesday, in response to the significant electric outages, NJNG supplied 84,536 Dth to customers, an almost 60% growth in daily demand in 24 hours. By the end of the week after most of the power was restored, the daily gas supplied by NJNG had dropped back to 58,394 Dth, in line with pre-storm sendout. Table 3-3 details the natural gas supplied by NJNG between August 3 and August 9, 2020.

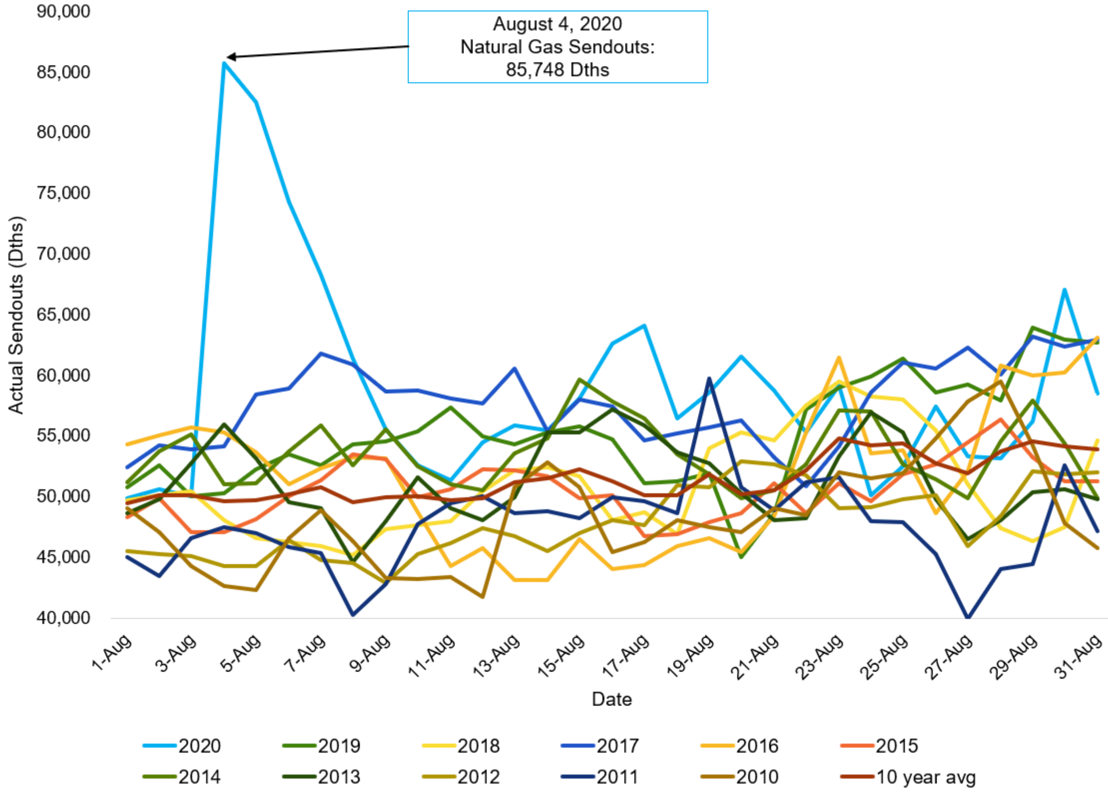
Table 3-3. NJNG Load Sendout: August 3, 2020 through August 9, 2020

Day	Date	Base Load Sendout (Dth)	Notes
Monday	8/3/2020	54,000	Pre-Storm Baseline
Tuesday	8/4/2020	85,536	Storm Hit 788,000 JCPL customers impacted
Wednesday	8/5/2020	84,198	Widespread Power Outages
Thursday	8/6/2020	78,688	Widespread Power Outages
Friday	8/7/2020	71,497	Widespread Power Outages
Saturday	8/8/2020	62,945	Majority of Power Restored
Sunday	8/9/2020	58,394	Majority of Power Restored

Source: Guidehouse, New Jersey Natural Gas

The daily natural gas output supplied by NJNG from August 4 through August 7, 2020 was higher than the daily output of any other August day for the previous 10 years. Figure 3-9 shows the 10-year average sendout from NJNG, the sendout from NJNG for the month of August 2020 identifying the dramatic peak from August 4 through 7, and the actual sendout from NJNG for August 2010-2019.

Figure 3-9. NJNG Comparison of August Actual Sendouts (Firm)



Source: Guidehouse, New Jersey Natural Gas

NJNG accredits most of the 30,000 Dth to 35,000 Dth increase in natural gas sendout during the storm to powering whole house generators, which served as backup power for customers who lost their electric supply. This load increase is estimated by NJNG to correlate with approximately 4,200, 20 kW generators running at full load (calculated using the assumptions in Table 3-4), or likely a larger number of natural gas generators running at partial load.

Table 3-4. Home Natural Gas Generator Assumptions

Generator Size (kW)	therms/ hour	dth/ hour	dth/ day	At 30,000dth/day number of 20 kW generators
20	3.00	0.30	7.20	Approximately 4,200

Source: Guidehouse, New Jersey Natural Gas

Conclusion

In August 2020, NJNG was not only able to withstand the hurricane, but it was also able to ramp up natural gas sendout quickly by relying on storage, allowing thousands of homes and businesses across New Jersey to keep their gas systems in operation when electric service was disrupted. Because of the built-in flexibility and dispatchable nature of the gas system, the gas system can complement the broader energy system as it responds to extreme climate events and keeps power flowing.

Case Study 6: Gas-to-Power Interface (California)

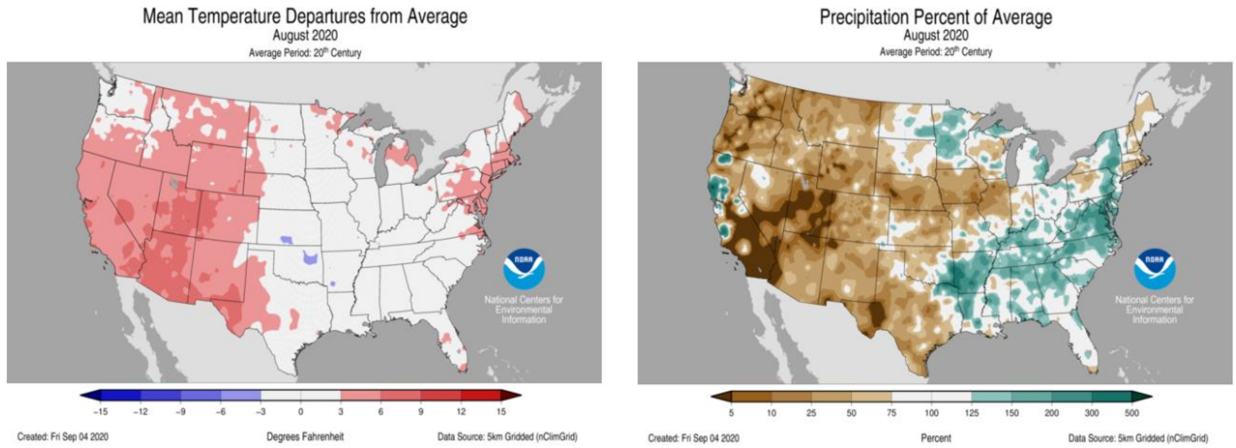
Key Finding

SoCalGas used storage capacity resources to meet the supply needs of gas-fired generation plants when the California electric system was experiencing multiple days of high demand from a record-breaking heatwave and unplanned decreases in other sources of electric generation.

Introduction

In August 2020, California was in the middle of its hottest August (record warmest in 126 years),[30] a severe drought (Figure 3-10), and its worst wildfire season in modern history. While California experienced increased demand on the electric system driven by increased cooling loads, it also experienced a decrease in the renewable output (due to smoke from the fires)[31] and imports than had been anticipated by electric supply planners. During these severe multi-day climate events, the gas system provided the flexible support required to ensure the broader energy system could provide power and prevented more extensive power outages.

Figure 3-10. August 2020 Mean Temperature and Precipitation, Departure from Average



Source: National Oceanic and Atmospheric Administration

On a standard summer day, California's electric grid is supplied by a wide variety of electric generation, renewables, natural gas, hydro, nuclear, coal, and imports from other regions. July 12, 2020 exemplifies a standard summer day in California (while the state was starting to experience a severe drought in July, average temperatures were within the normal range).[32]

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30 NOAA. National Climate Report – August 2020. https://www.ncdc.noaa.gov/sotc/national/202008

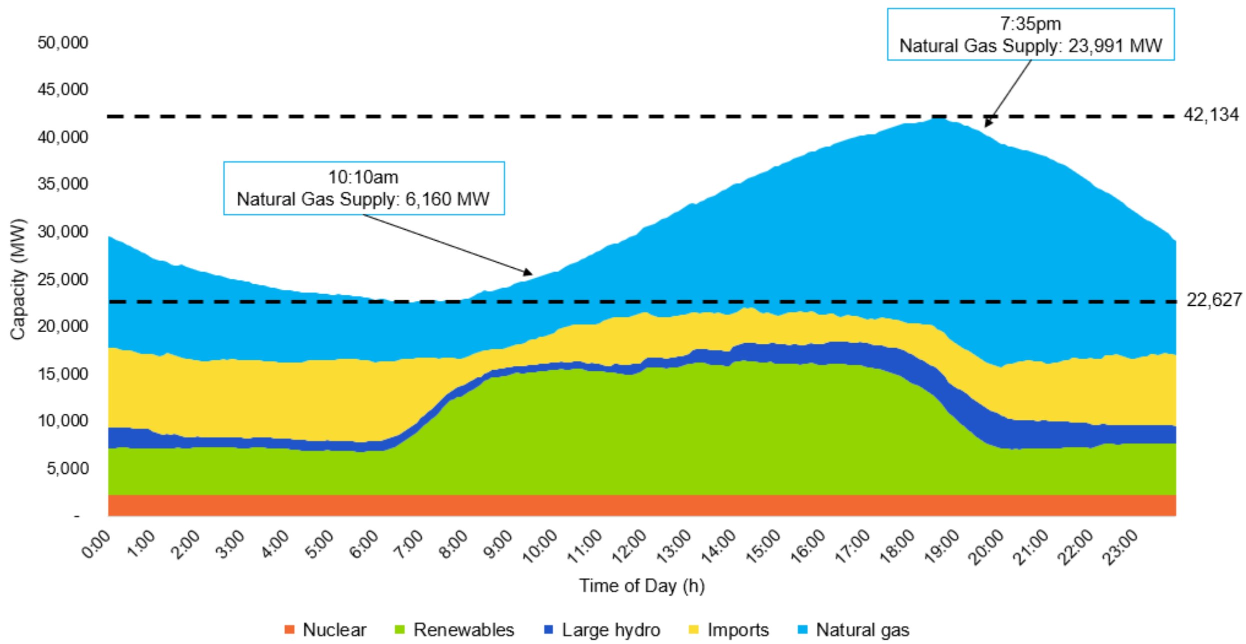
31 EIA. *Smoke from California Wildfires Decreases Solar Generation in CAISO.* September 30, 2020. https://www.eia.gov/todayinenergy/detail.php?id=45336

32 NOAA. National Climate Report – July 2020. https://www.ncdc.noaa.gov/sotc/national/202007

Overview

As Figure 3-11 shows, on July 12, 2020 renewable generation began to increase at around 06:30 hrs and remained relatively steady until approximately 17:00 hrs, driven primarily by solar generation during sunlit hours. By 08:00 hrs renewables provide 50% of the state's electric power generation, natural gas provides 25%, and the other sources provide the remaining 25%. As the day continues, gas-fired generation ramps up. By 20:00 hrs natural gas provides 60% of the electric power generation required to meet the peak load.

Figure 3-11. CAISO Supply Trend to Meet Electric Demand, July 12, 2020[33]



Source: Guidehouse, California Independent System Operator

Gas generation plants ramp up to meet peak demand, but the fuel demand of the generation plants is not ratable. Ratable is generally described as levelized demand where deliveries are made evenly throughout a delivery day. The hourly demand for gas to supply these generation plants often exceeds supply receipts, as arranged by the power plants, into the gas system. To overcome the imbalance between supply and use and to respond to the volatile demand needed to maintain the integrity of the electric system, underground storage plays a vital role.

Storage capacity and the stored commodity are contracted for in advance. Underground gas storage is expected to be used to maintain grid load balance and operation on high heat summer days (a hallmark of grid resilience). However, reliance on gas storage systems and the dispatchable nature of gas generation when the energy system is under higher stress (experiencing a resilience event), as seen in August 2020, requires a more significant drawdown of underground storage assets.

> *During the hours of highest electricity demand, gas generation provides the bulk of California's electric power generation.[34]*

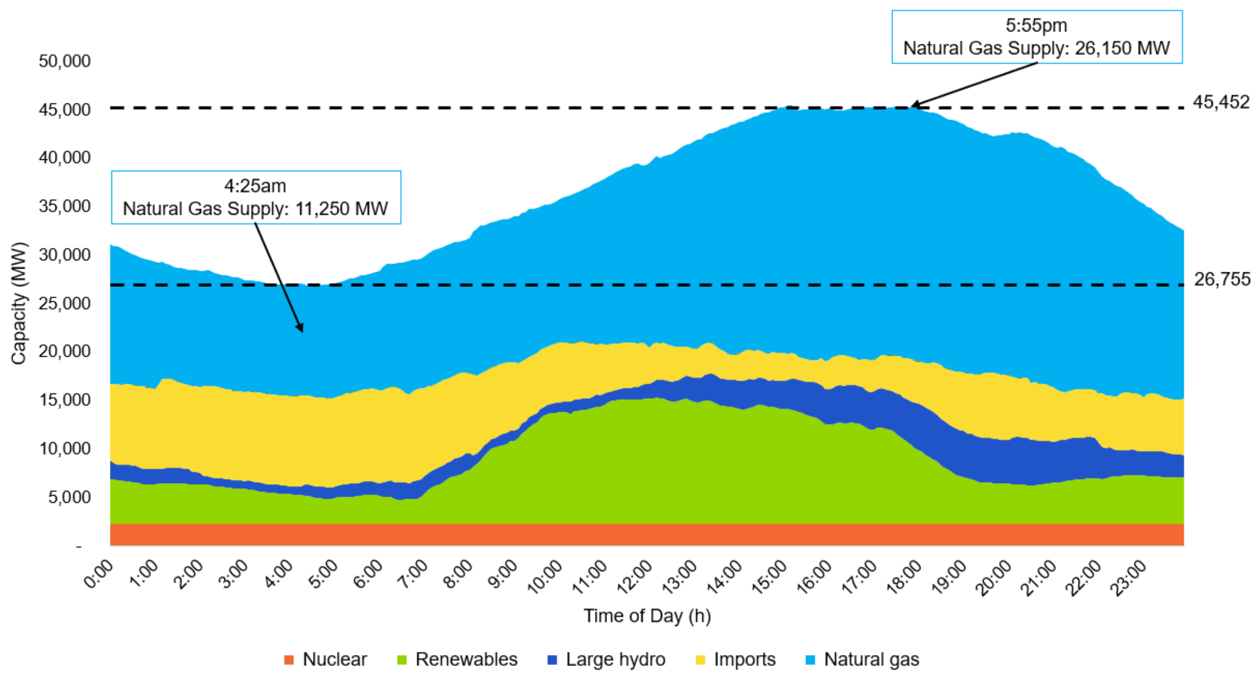
[33] Batteries and coal contribute negligible amounts (± 50 MW) and are not shown within the figure.

[34] CAISO. 2020. "Supply and renewables."

The week of August 11, 2020 is a prime example of the California electric grid under a resilience event—coinciding extreme heat, drought, and wildfires. During this week, California experienced severe climatic events and associated higher electric consumption. Renewable output was also more variable and diminished due to heat, clouds, and wildfires, and power imports were lower than expected, since the entire western half of the US was experiencing the same heatwave as California.

Figure 3-12 illustrates the resources that contributed to CAISO's electric generation on August 17, 2020. Renewable generation supplied less electricity on August 17 compared to July 12 (peaking at around 13,000 MW at 12:00 hrs compared to over 14,000 MW at 14:00 hrs). Peak load was 45,452 MW on August 17, while on July 12 peak load was 42,134 MW. To meet the higher peak load and make up for the lower renewable generation, on August 17, gas-fired generation made up a higher percentage of CAISO's electric power generation capacity.

Figure 3-12. CAISO Supply Trend to Meet Electric Demand, August 17, 2020[35]



Source: Guidehouse, California Independent System Operator

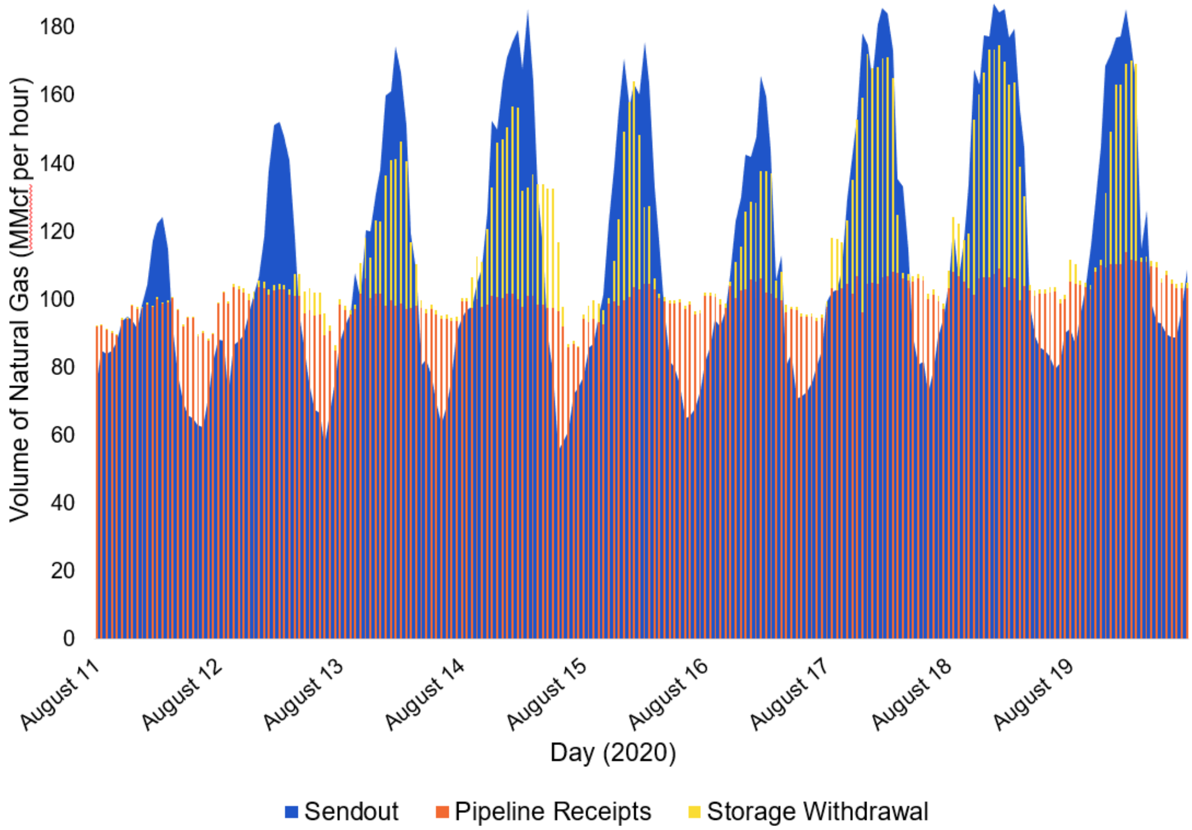
To meet the pressure on the CAISO system during the week of August 11, electric system operators turned to gas-fired generation facilities. To ensure that these generation plants had the natural gas supply to maintain the integrity of the electric grid, SoCalGas had to draw significantly on its gas system storage assets.

Figure 3-13 provides an hourly view of pipeline receipts into the SoCalGas distribution system, sendout, and withdrawals from storage. The blue vertical bars illustrate the hourly demand and sendout from the SoCalGas system. The orange vertical bars depict the quantities that were received into the system, which is generally received in steady hourly quantities over the course of the day. The yellow vertical bars above the receipts illustrate the volumes required to be withdrawn from storage on an hourly basis to meet the far more variable and changing intraday needs of electric generators, which exceeded the gas supplies arranged for delivery into the

[35] Batteries and coal contribute negligible amounts (± 100 MW) and are not shown within the figure.

SoCalGas system each day. The imbalance between daily pipeline receipts and sendout (mostly to serve the load of electric generators) was most significant on August 17 and 18, when sendout for each day was ~3.1 Bcf, while receipts were 2.5 Bcf, resulting in a deficit of ~0.6 Bcf daily, which was required to be made up by on-system storage.

Figure 3-13. Hourly Supply and Demand on the SoCalGas System



Source: Guidehouse, SoCalGas

From August 11 to 19, pipeline receipts on the SoCalGas system were approximately 100 MMcf per hour (2.4 Bcf per day/24 hours). In this same period, deliveries to SoCalGas customers exceeded 100 MMcf per hour during approximately 110 of 168 hours, or 65% of the time. August 11 was the only day SoCalGas was able to meet the peak delivery in excess of pipeline receipts through utilization of linepack (i.e., no storage withdrawal). On all following days, withdrawals from underground storage played a critical role when hourly consumption exceeded pipeline receipts.

Hourly withdrawals in excess of the equivalent of 800 MMcfd were experienced more than a dozen times between August 15 and 19. Those withdrawal rates were only possible with withdrawals from all SoCalGas' storage fields, including Aliso Canyon. The week of August 11, 2020, the totality of SoCalGas' system assets were employed to address the shortfall between abnormally high electric demand and low renewable energy generation experienced in Southern California.

Conclusion

Due to COVID-19-related impacts, C&I demand during this period was lower than normal. Although storage was critical to filling the gap between supply and demand, SoCalGas estimates that—had C&I demand been closer to average historic levels—it is likely that the capacity of the SoCalGas transmission and storage system would have been exceeded, which could have resulted in curtailment of electric generation. This is due to SoCalGas' planning standards and priority of services that are primarily focused on core customers, the SoCalGas tariff deprioritizes service to electric generators and allows curtailment during constrained/high demand periods. This situation is not unique to California, in other jurisdictions, electric generation, in the event of a curtailment, is given a lower level of prioritization compared to residential customers.

> *If the gas system was not able to fill the gap between abnormally high electric demand and low renewable energy generation to support the overall resilience of the electric system, Southern California would likely have experienced severe power outages during the system resilience event experienced in August 2020.*

The gas system fosters electric system reliability and serves as a resource that is capable of readily addressing unplanned or unforeseen events within the integrated energy system. When these resilience events occur, electric generators can experience large intraday swings in their need for gas supplies, often with little to no notice. In regions where the intermittent use of the gas system for electric power generation is a significant portion of total gas use on the system, this unpredictable non-ratable flow can stress the physical gas delivery system. Although the physical infrastructure including pipeline transportation and storage assets are in place and able to accommodate this type of intermittent usage, the underlying market framework and regulatory structure were not designed to provide this type of support service to the overall energy system. In general, the regulatory structure does not provide a means to construct and operate investments that provide resilience protection. That the gas system can provide this service demonstrates how resilience is a byproduct of the engineered reliability features of gas delivery system. The result being that the gas system and the gas LDC ratepayers provide this resilience service to the overall energy system without receiving compensation commensurate to its value.

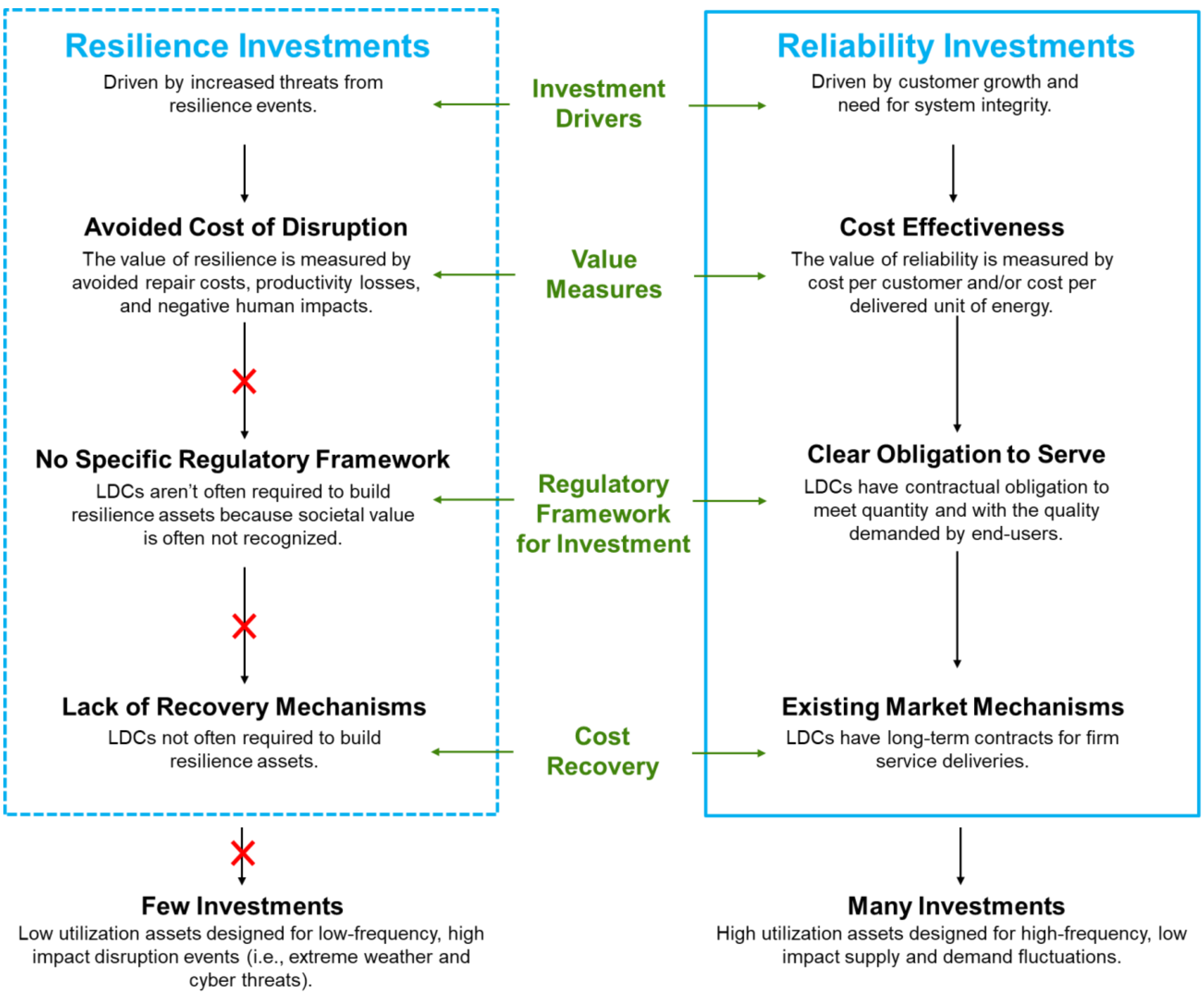
4. Current Regulatory, Policy, and Market Structures

The first half of this report established that the gas system provides resilience to the US energy system. The second half focuses on the regulatory, policy, and market structures that underpin the US energy market. This section explores the current state, including how these structures have developed and the challenges they create. Section 5 considers forward-looking considerations to ensure future energy system resilience.

4.1 The Difference Between Resilience and Reliability Investments

The current market economic framework is designed to support the development of physical assets with high utilization or those backed by long-term contracts. These assets provide reliability services to the energy system. Reliability assets often contribute to the resilience of the energy system as a byproduct, but they are not designed to meet the full needs of a resilience event. Figure 4-1 explores the differences between resilience and reliability investments.

Figure 4-1. Comparison of Resilience and Reliability Investments



Source: Guidehouse

4.2 Historical Context of Gas System Development

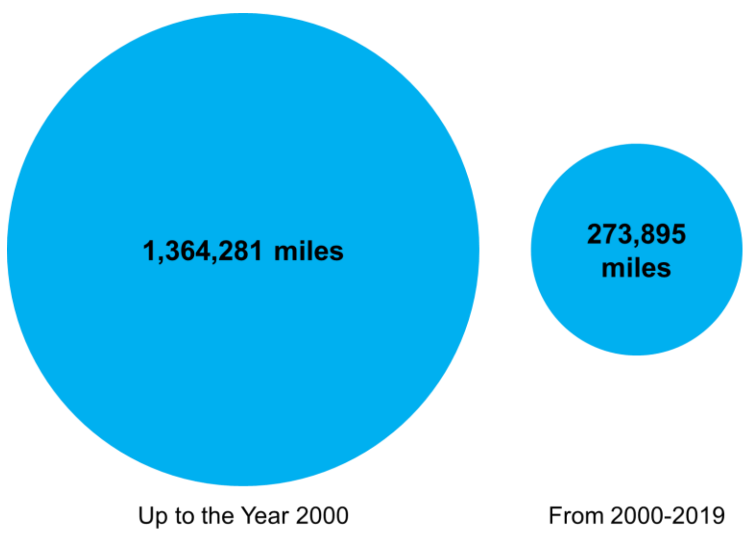
To fully understand some of the challenges in regulatory, policy, and market structures around the development and support for the use of natural gas as a resilience asset, it is necessary to understand the historical context around how these frameworks have developed. In this section, we consider the historical context of the development of the gas system and what implications that has had on the structure and the gas system's current support of energy system resilience.

Natural gas was first used in the early 1820s. However, lacking efficient transportation options, its usage was limited to powering light sources, usually close to natural gas wells. In the late 1890s, gas pipeline construction began and partnered with technological advances, this more efficient transportation of the resource fueled the growth of the US pipeline and connected natural gas wells to users—homes, businesses, and heavy industry. It was not until the late 1990s (really after 2000) that natural gas became a significant source of US electric power generation.

4.2.1 Residential, Commercial, Industrial Load (Pre-2000)

The majority of US natural gas gathering, transmission, and distribution pipeline infrastructure that exists today (approximately 83%) was built out prior to 2000, as Figure 4-2 shows. This infrastructure was built based on a paradigm of predictable and relatively stable demand from residential, commercial, and industrial loads—and stable investor returns. There are several mechanisms that pipeline companies and LDCs use to maintain the integrity of their systems in accordance with Federal law. Across the US, state utility commissions have approved infrastructure modernization programs and pipeline replacement programs to address aging infrastructure. A total of 41 states and the District of Columbia have adopted an approach to support the prioritization, financing, and execution of gas infrastructure upgrades. These programs not only increase the safety of the energy system, but also enhance the future resilience of the energy system.[36]

Figure 4-2. Incremental US Natural Gas Pipeline Additions

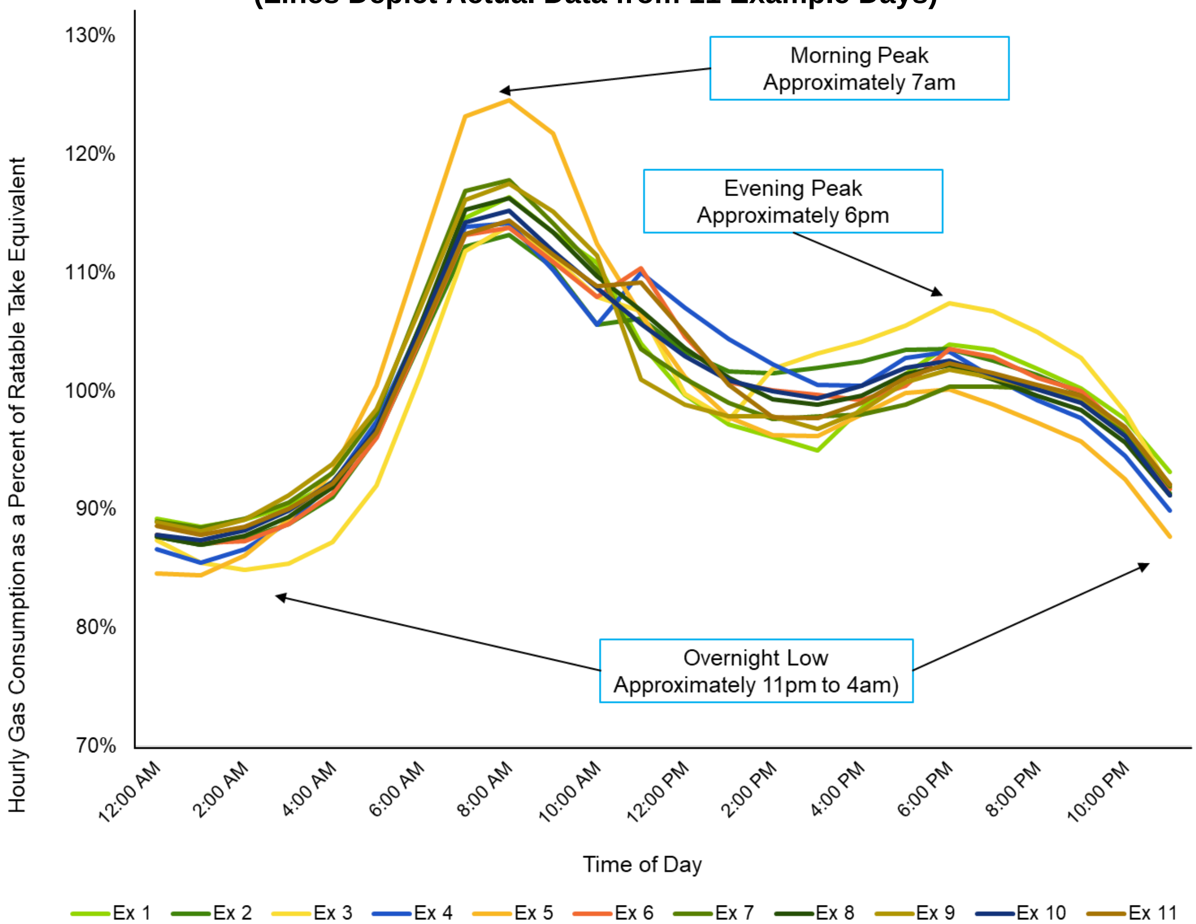


Source: Guidehouse, US Bureau of Transportation Statistics

[36] NARUC, January 2020. Natural Gas Distribution Infrastructure Replacement and Modernization.

The aggregate daily gas demand to serve residential, commercial, and industrial customers is predictable and relatively stable. Gas usage for these customers increases significantly in the morning before slowly decreasing over the course of the day. There is an additional, relatively minor, increase in the evening around dinner time before gas usage drops over the night. Figure 4-3 presents the aggregate load profile for these customers. The figure's y-axis indicates percent variation in hourly gas consumption as a percent of ratable take equivalent[37] and the minimum and maximum peaks only vary -16% to +25% from that daily average.

Figure 4-3. Aggregate Daily Natural Gas Load Profiles, for Residential, Small Commercial, and Industrial Customers (Lines Depict Actual Data from 11 Example Days) *



*Source: Guidehouse, Consumers Energy**

The gas usage pattern is predictable for these customer groups, even in varying climatic conditions. In colder conditions, the usage pattern features less volatility as demand for space heating is more constant throughout a cold day. In warmer conditions, the peaks and troughs widen, and the total daily usage is lower. The predictability of this trend enables gas LDCs to construct and operate the gas system and build new assets with a high degree of confidence in the use of those assets.

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[37] *Ratable take equivalent* refers to the comparable amount of gas consumed in one day on a levelized basis over a 24-hour period, i.e., in even 1/24th increments. This is further discussed in Appendix A, Section A.3.1.

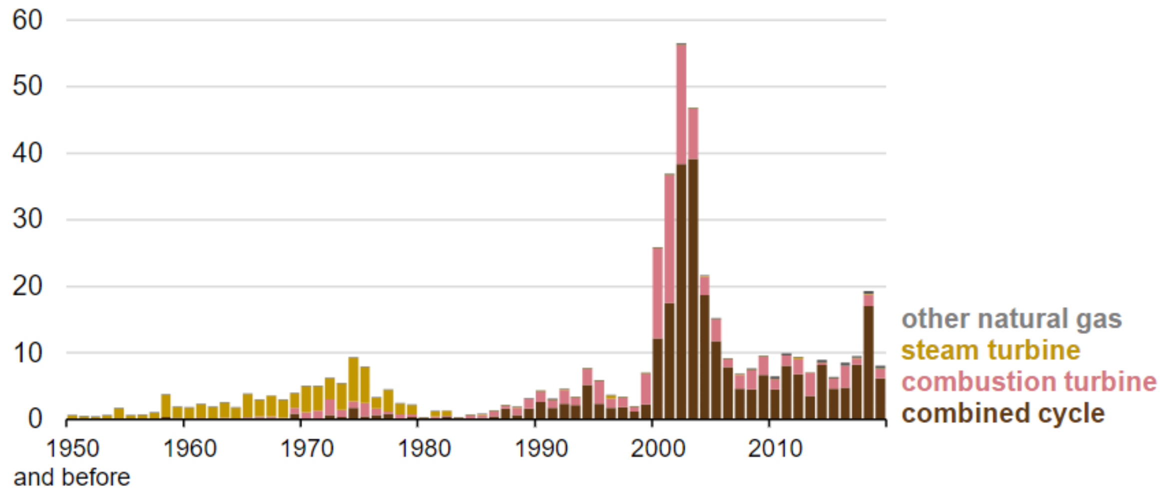
> *The gas system that serves the US today was built to serve the residential, commercial, and industrial sectors, where the relative predictability of usage over the course of a day (ratable takes) and throughout the year for these customer segments enabled LDCs to design, construct, and operate the gas system with a high degree of confidence in how the gas system would be used to serve demand.*

The entirety of the gas value chain's economic and operational framework is underpinned by this ratable system of supply and demand.

4.2.2 Gas-Fired Electric Generation (Post-2000)

When much of the current gas system was designed, the electric sector was a small component of overall demand. Between 1949 and 2000, gas-fired generation provided an average of just 16% of total electric power generation in the US on an annual basis. Since 2000, this has increased significantly. In 2019, natural gas accounted for 38% of US electric power generation and provided 43% of operating US electric power generating capacity.[38] Figure 4-4 explores this trend and shows that most of the growth in gas-fired generation capacity occurred between 2000 and 2020. More information on the role of natural gas in the electric power generation sector can be found in Appendix B.

Figure 4-4. US Gas-Fired Electric Power Generation



Source: US Energy Information Administration

4.3 Natural Gas in Electric Power Generation

There are critical differences in the way that gas-fired generation interacts with the gas system. This section explores those differences. In general, gas-fired generation plants fall into one of two classifications:

1. **High-capacity factor generation:** These low-heat rate/high-efficiency plants support electric power generation by operating often at close to full capacity 24/7.

[38] EIA. 2020. [Electricity: Current Issues and Trends](#).

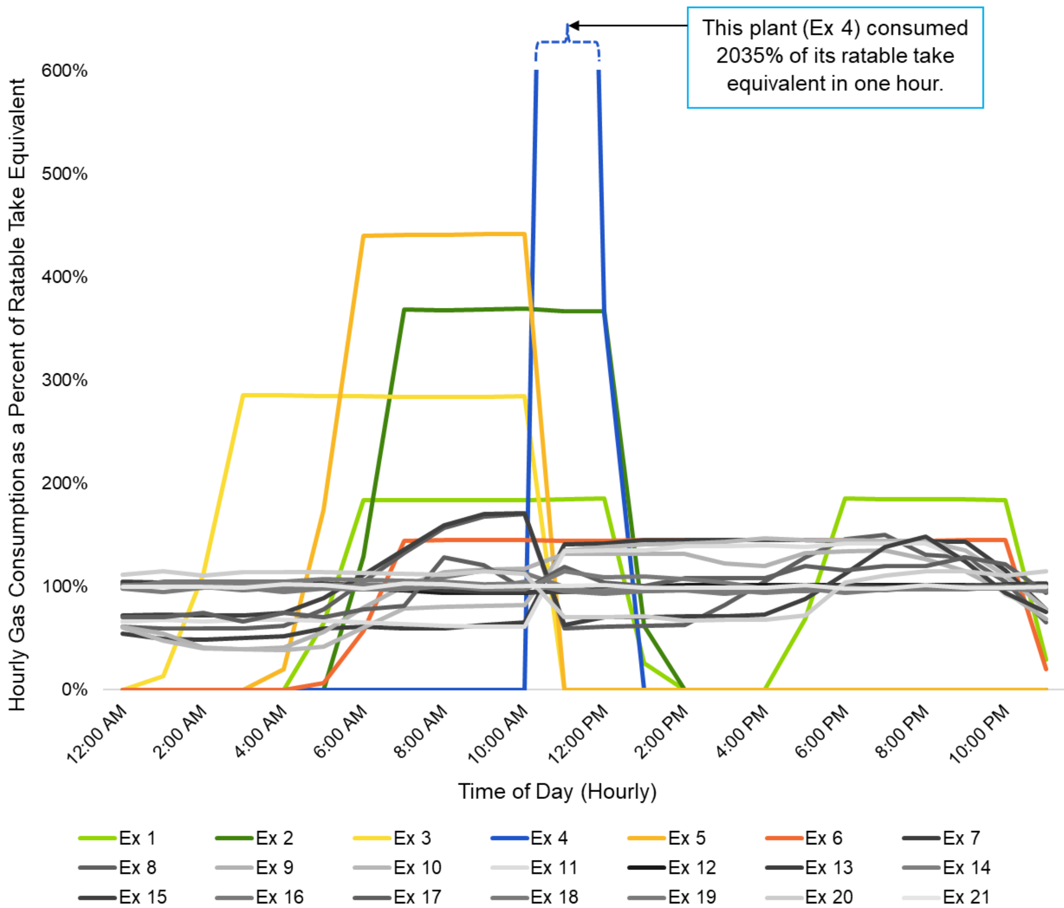
2. **Intermittent generation:** These plants serve as dispatchable resources for electric system operators, ramping their generation up and down quickly to fill the gaps between intermittent generation sources (such as renewable sources) and consumer demand.

4.3.1 Gas-Fired Electric Power Generation Load Profiles

Figure 4-5 illustrates the load profiles of six different gas-fired electric power generation plants over a period of 21 days. Gas load profiles of gas-fired electric power generation plants exhibit far more variance on a daily and hourly basis than the load profiles of residential, commercial, and industrial customers. In Figure 4-5, high-capacity factor generation plants are identified generally in gray (Ex 7 through Ex 21) and those serving intermittent generation capabilities are identified with varying colors (Ex 1 through Ex 6).

The load profile for high-capacity factor gas-fired plants (Ex 7 through Ex 21 in Figure 4-5) generally features a morning and evening peak, and the variation between the highest hour of usage and the lowest hour of usage from ratable take equivalent is 71% to -61%, similar in pattern to the load profiles for residential, commercial, and industrial customers but the magnitude of the swings are larger.

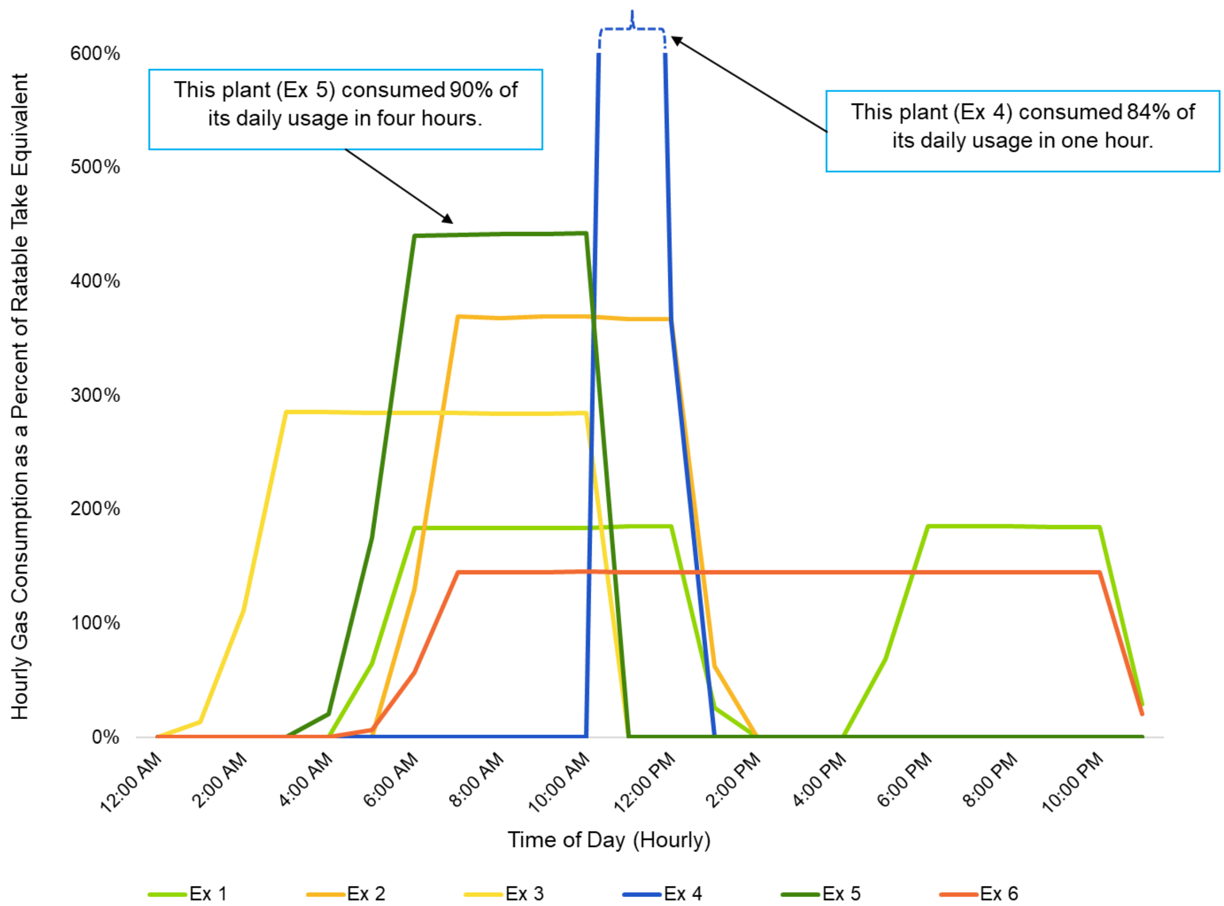
Figure 4-5. Daily Natural Gas Load Profiles for Gas-Fired Electric Power Generation (Lines Depict Actual Data for 21 Example Days, Data is Inclusive of Six Facilities)



Source: Guidehouse, Consumers Energy

Gas-fired plants that run intermittently exhibit a different load profile from the relatively predictable daily variation of high-capacity factor plants. In Figure 4-6, the high-capacity factor generation daily load profiles were removed to focus on the load profiles of intermittent gas-fired plants. The load profiles associated with these plants exhibit a high level of variability and intraday swings, as the plants quickly ramp up and down from their peak rates.

Figure 4-6. Daily Natural Gas Load Profile for Intermittent Gas-Fired Plants (Lines Depict Actual Data for Six Example Days, Data is Inclusive of Six Facilities)



Source: Guidehouse, Consumers Energy

The gas supply required by intermittent gas-fired plants is characterized by large volumes of fuel that are subject to a level of variability and intraday demand swings that are vastly different from how the residential, commercial, and industrial sectors consume gas over the course of a 24-hour period.

> *Intermittent gas-fired plants are primarily used to fill gaps between other intermittent generation sources (such as renewables) and customer demand for electricity. They are only capable of fulfilling this role because the gas delivery system enables the delivery of supply to serve the swings needed to provide such a quick-start response. Although the gas system fulfills these needs, the physical delivery system and the supporting market mechanisms and commercial terms that govern day-to-day operations were not designed for this type of usage*

4.3.2 Implications for the Gas Delivery System

Upstream pipeline deliveries to the gas distribution system occur at relatively steady hourly quantities throughout a day, but gas is not consumed in even hourly increments over the course of a day. Gas distributors have a variety of tools including linepack, storage, and mobile delivery capabilities to accommodate this intraday swing in demand and enable deliverability and respond to increases and decreases in consumption.

The gas transmission system is designed to accommodate the delivery needs of the predictable and low variability patterns required of residential, commercial, and industrial customers. Meeting the variable delivery needs of high capacity factor and intermittent gas-fired plants is a greater challenge as the gas consumption of these plants is much more variable, especially for intermittent gas-fired plants. Gas system operators supplement hourly pipeline receipts with linepack and storage withdrawals to maintain integrity and meet the needs of intermittent plants.

The gas distribution system's ability to provide this intermittent deliverability service is highly dependent on the amount of gas in the pipeline, the inventory levels in storage, the inventory in other storage assets, and contractual obligations to other customers. Providing service to gas-fired generators, particularly intermittent gas-fired generators requires coordinated planning from operators of the gas and electric systems.

4.4 The Regulatory Context

This section discusses how the current regulatory structures hinder the construction, utilization, and operation of new gas assets to serve resilience needs. Often, current regulatory structures tie the development of interstate pipeline and storage assets strictly to the needs of customers (producers, gas utilities, and other end users) willing to execute long-term firm service contracts. These do not easily support the construction, utilization, and operation of resilience assets that, by their nature, will be used infrequently to support low likelihood, high impact events. As a result, gas systems may not be appropriately compensated for the resilience services they provide.

Two critical principles often underlie the regulatory approval of infrastructure development:

- **Alignment between who benefits and who pays:** The ability to demonstrate how an asset provides a benefit to those who pay for its development is a standard principal of utility ratemaking.
- **The business case hinges on high utilization:** The construction and operation of most gas assets are founded upon the willingness to execute long-term firm service contracts; higher utilization translates to lower cost per unit.

This framework begins to break down when asset development activities or business model economics are not aligned with these principles. Applying these regulatory principals to the consideration of the construction, utilization, and operation of gas assets for resilience purposes, two key challenges are exposed:

- Current gas system resilience is a byproduct of reliability investments
- Gas systems may not be appropriately compensated for the resilience service they provide

The remainder of this section discusses these two challenges.

4.4.1 Current Regulatory Framework for Infrastructure Approval

To construct a new energy system asset, a gas utility must receive approval from its regulator, typically a state-level public utility commission. The investment is typically approved if the gas utility demonstrates the investment is prudent and serves the needs of its customers.

The principle of alignment between who benefits and who pays is applicable to regulating the expansion or new construction of interstate pipeline and storage infrastructure. A utility is responsible for the burden of proof of necessity on behalf of its customers. For interstate pipeline and storage assets, the burden of proof is on the market need demonstrated by customers who have executed precedent agreements.

The Federal Energy Regulatory Commission (FERC) regulates interstate pipeline and storage markets. Pipeline and storage operators seeking regulatory approval to construct or expand an asset must provide FERC with a demonstration of market interest to receive approval. FERC grants approval if this market interest can be demonstrated. Due to the long life of pipeline and storage assets, the regulators seek to balance the interests of customers with landowners and the public around environmental concerns,[39] as well as the financial viability of the project. Market interest is demonstrated in the form of customer execution of long-term firm service contracts, where firm service entails a right to a predetermined amount of capacity on the pipeline during the agreement period.

Natural gas utilities are regulated by state public utility commissions (PUCs). PUCs approve infrastructure investments based on the concept that the investment provides utility service and supports the utility's obligation to serve. Gas utilities enter long-term firm capacity contracts because they are required to fulfill an obligation to serve their customers, particularly during periods of peak usage. For example, a gas utility with a significant winter peaking load will subscribe to a long-term contract to serve that load even if its firm rights to pipeline capacity will be underutilized in the summer—resulting from the utility's obligation to serve.

> *A fundamental underpinning of regulatory approval for interstate pipeline and storage construction is the demonstration of market need, as supported by customer willingness to enter long-term contracts for firm capacity.*

When pipeline or storage customers are not willing to enter long-term firm contracts, the market structure creates barriers to obtain the right to a predetermined capacity that is not subject to a prior claim from another customer. This is an issue for certain gas-fired electric power generators. Electric power generators profit if their cost of producing power (fuel plus operations and maintenance) is lower than the average price they sell electricity. Given most gas-fired powered generators are unable to store fuel onsite, they must rely on quick response delivery of natural gas, resulting in two unequal options:

- **Sign a long-term firm contract.** While an option, it is not typical because it could increase the cost such that it is not competitive with other sources of generation, i.e. coal and fuel-oil plants that can store fuel onsite, and solar and wind power that do not require fuel input.
- **Sign a secondary or interruptible contract.** Most gas generators take this action because the economics are more favorable. Interruptible capacity refers to pipeline transportation capacity that is available when the holder of the firm right to this capacity

[39] FERC. 2020. "The Natural Gas Pipeline Application Process at FERC."

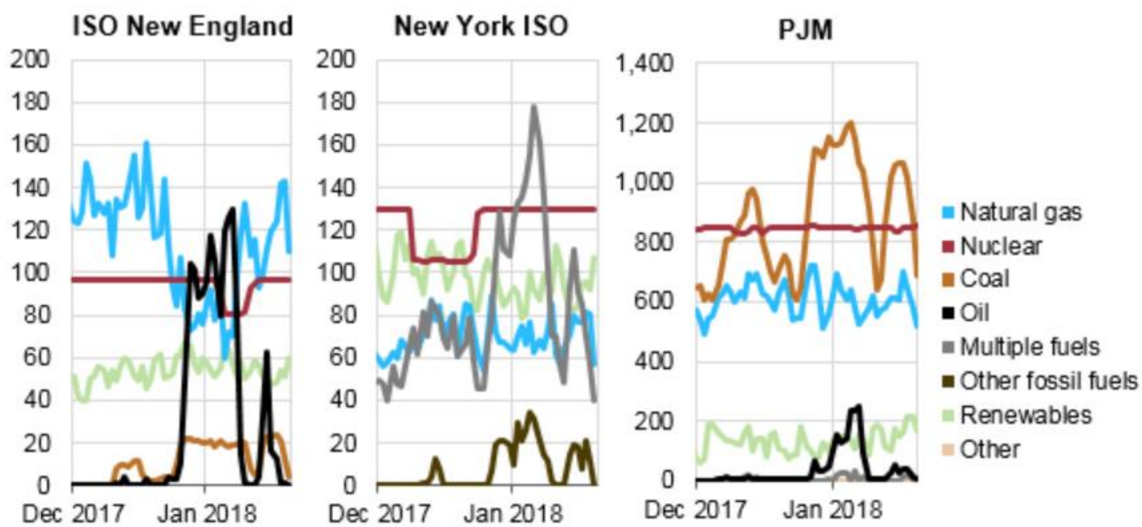
is not using it. The risk is that the pipeline or storage capacity may not be available when it is needed.

4.4.2 Regulatory Framework and Implications to Resilience

In periods of peak usage (e.g., during periods of high use), holders of firm pipeline transportation are likely to use their full allotment of capacity, leaving little to no capacity to secondary or interruptible contract holders. In these periods, gas-fired generators without firm capacity will likely be constrained. During periods of high use, a constrained gas pipeline can create economic or operational conditions that lead to increased fuel switching to oil-fired or dual-fuel generation. This has caused and can cause risk that electric generators lose the ability to serve peak electric load when customer demand for gas supply is also at its peak. This constraint is further illustrated in Figure 4-7.

Figure 4-7 details fuel switching in three electricity markets in the northeast (New England, New York, and PJM) during the January 2018 bomb cyclone. In early January, as the Northeast experienced the cold weather related to the bomb cyclone, demand for electric power generators increased as natural gas transportation was constrained.

Figure 4-7. Comparison of Electric Power Generation During the January 2018 Bomb Cyclone[40]



Source: US Energy Information Administration

- In ISO New England (ISO-NE), oil generation jumped from almost nothing to a high of 36% of the daily generation mix. In comparison, gas-fired generation decreased from approximately 50% to less than 20% of supply.
- On New York ISO's (NYISO's) system, the output of dual-fuel generators, mostly gas-fired generators that can switch to fuel oil, and other fossil fuel generators rose significantly.
- In PJM, oil and coal generation increased while gas-fired generation remained consistent.

[40] EIA. 2018. Northeastern Winter Energy Alert.

Gas-fired generation did not make up the required increase in demand to meet the increased electric power generation needs during the 2018 bomb cyclone event. The structure of the underlying electricity markets, specifically the reliance on unused pipeline capacity for fuel delivery for gas-fired generation to maintain competitiveness, poses a challenge to investments in gas infrastructure in the electricity markets such as ISO-NE, NYISO, and PJM.

4.4.3 Current Gas System Resilience Is a Byproduct of Reliability

The current model for developing gas infrastructure supports construction of assets that support reliability of service and that can be underpinned by long-term contracts. This model has been supportive for maintaining the resilience of the gas system, but it must be recognized that the model does not reflect how the gas system will be operated in the future. It also does not support construction of assets that support resilience requirements.

As demonstrated by the case studies, gas infrastructure provides resilience benefits to the entire energy system. However, the strength of the current gas system is a byproduct of an outdated regulatory system, optimized around daily reliability instead of long-term resilience. Fortunately, the overlap between the two outcomes is considerable enough that the energy system currently experiences a reasonable level of resilience. However, the current regulatory structure does not provide a means to construct and operate investments primarily for resilience. As the transformation of the energy system continues, we anticipate the need for more resilience and a changing mix of assets required to provide that service. The manner in which this energy system is regulated and managed is becoming outdated; thus, an update is necessary to maintain resilience in the evolving future energy system.

4.4.4 Gas Systems Are Not Appropriately Compensated for Resilience Services

From a regulatory perspective, LDCs have an obligation to serve and must develop supply and transportation plans to provide gas reliably at the lowest sustainable cost. Typically, gas distribution utilities do not procure more gas supply than necessary for a given day and instead use storage and linepack to balance intraday supply and demand. In most cases, LDCs cannot secure regulatory recovery to procure and store additional gas supply for low likelihood, extreme climate events beyond that incorporated in reserve margin planning. When a customer draws significantly more gas from the gas system than its average demand, this additional supply comes from gas stored that is already allocated to another customer.

> *Any incremental supply that is available to serve electric power generation on short-notice will be gas that has been reallocated from other customers unless the pipeline or LDC offers a no-notice service.*[41]

Some interstate pipelines and gas distribution companies offer no-notice service on a firm basis by dedicating pipeline and storage infrastructure to support the delivery of gas on short notice—no-notice service is typically supported via interstate pipeline tariffs. An electric power generator may pay the cost of expansion of pipeline or storage assets to support the maximum volume consumed. Example 4 (page 57) is a good illustration of this scenario.

In other cases, providing gas supply on short notice to serve resilience events is limited by several features of the gas delivery system. From a physical perspective, the incremental supply

[41] No-notice service refers to the delivery of natural gas on as-needed basis, without the need to precisely specify the delivery quantity in advance (quantities within contract entitlements).

consumed on an intraday basis needs to be in the pipeline at the moment the electric power generator requires delivery throughout the period that the electric generator is producing power. The accommodation of non-ratable flows in the gas system depends on how other shippers use their contracted entitlement in the pipeline and the operational flexibility of the pipeline (e.g., line pack and storage availability). If the pipeline is already full, extreme spikes in demand from non-ratable users may not be met.

The LDC delivery system was not designed to provide large volumes of no-notice service to the electric power generation sector. However, in many circumstances, LDCs provide non-ratable service when capacity is available and when it does not threaten operations. In these cases, the gas system supports the energy system's overall resilience but is not adequately compensated for its service. This lapse in compensation occurs because an additional service is being provided with assets that were not designed for the circumstances.

4.5 Impacts on Consumers

This section considers the varying level of the impact of the findings on the current state on gas ratepayers and electric ratepayers. At a high level, gas ratepayers are more closely aligned with gas system resilience investments than electric ratepayers, as there is no misalignment around who benefits and who pays. Electric system ratepayers, who benefit from the gas system through gas-fired generation have greater misalignment with the development of gas system resilience investments.

4.5.1 Gas System Resilience to Benefit Gas Ratepayers

LDC customers benefit from the resilience provided by assets that are built to provide reliability. Assets are built to serve gas ratepayers. There is a disconnect between who benefits and who pays. The resilience byproduct of these assets benefits these customers. Construction of an asset that is primarily designed for resilience is problematic, because:

- **Lack of a Regulatory Framework:** Resilience of the gas system is not a current regulatory requirement.
- **Lack of Metrics:** Unlike reliability, which can be measured, resilience does not lend itself easily to quantification. For example, value of avoiding the socioeconomic consequences and costs of a prolonged disruption is difficult to measure.

The lack of a regulatory framework and the difficulty of measuring the value complicates the prudency review and cost-effectiveness evaluation of an asset whose business purpose is resilience. As such, reliability drives investment in gas infrastructure. Assets are designed and approved to meet reliability requirements driven by projected gas supply needs and delivery requirements for peak day usage based on historical data. A specific regulatory mechanism to support cost recovery for gas assets whose primary service is to serve resilience events does not exist and needs to be developed.

4.5.2 Gas System Resilience for Electric Ratepayers

There is a larger disconnect between current market structures and the development of resilience assets when the beneficiaries of gas system reliance are not direct gas system customers, such as electric market customers.

- **Difficulty to recover costs across complementary energy markets:** While there is a connection between the resilience of the gas and electric systems, there is no mechanism for electric market participants to collect revenue or provide cost recovery for investments in gas system resilience.

The gas delivery system was not constructed to handle the increasing frequency of large intraday swings in service demand by gas-fired generators that serve intermittent load. As discussed in Section 4.3.2 and as described in Case Study 6, the gas system accommodates the non-ratable flow of the electric sector on a best-efforts basis. In many cases, pipeline transportation arrangements, tariffs, and coordination efforts exist between an LDC and specific electric power generators. However, these are generally workarounds that do not address the core issue: the current state market framework was designed to promote reliability and does not support the construction of assets whose primary function is to serve resilience, especially when the beneficiaries of that resilience are outside of the gas infrastructure-ratepayer ecosystem (i.e., the electric sectors' customers), nor does it fairly compensate the LDCs as the provider of these resilience services.

To further highlight the cost associated with the development of resilience assets, in Example 4 we discuss a gas infrastructure project specifically designed to serve the resilience needs of the electric sector. This example illustrates the benefits that the gas system can provide to the overall energy system when there is alignment between who pays and who benefits and there is a long-term contract to support development.

Example 4. Gas-to-Power Coordination

Portland General Electric (PGE), an electric utility in Oregon, has traditionally relied on hydroelectric generation resources to provide electric system flexibility. However, it sought new ways to achieve flexibility to meet the expansion of solar and wind generation capacity. PGE needed an efficient technology capable of quick-starting, as well as fast ramp-up and ramp-down rates to fulfil the grid's need for flexibility. PGE constructed a 220 MW electric power plant to provide intermittent power during winter and summer periods, as well as load following and renewable integration throughout the year. The plant can ramp to full load in less than 10 minutes.

To assure deliverability of natural gas to accommodate this quick start-up time, PGE partnered with NW Natural, an Oregon-based LDC, to contract for no-notice storage service. To provide this service, NW Natural embarked on a $149 million project that included a 13-mile gas pipeline, a compressor station, and a 4.1 Bcf expansion of the NW Natural' North Mist natural gas storage reservoir. Through this storage service, PGE can draw on its natural gas resources from NW Natural's facilities in Mist, Oregon to meet its fueling needs and rapidly respond to peak demand and variability of wind, hydro, and solar generation. The facility is contracted for an initial 30-year period with a renewal option of up to 50 years beyond that.

Currently, no specific compensation mechanism exists for the resilience services that gas-fired electric power generation provides the electric sector. In the future, as the percentage of electricity generation from intermittent renewable sources increases, the volume of natural gas used for electric power generation may decline; however, in responding to resilience events the necessity of the services provided by gas-fired electric generators may increase. As current compensation models for the gas system serving the power generation sector are tied to the volume of gas delivered to the facility, there becomes an increasing disconnect between the value of the services provided and associated remuneration for said services.

> *Reliability assets are designed and economically justified based upon historical averages and relatively stable utilization. Resilience assets are essential to operation under infrequent and extreme conditions. The benefits of their existence often extend beyond the energy system for which they were designed, i.e., resulting in a greater socioeconomic benefit such as reduced economic loss resulting from an extreme event.*

5. Ensuring A Resilient Future

The energy system of today will not be the energy system of tomorrow. Decreases in the cost of technologies and increasing pressures to decarbonize the energy system are manifesting in increasing levels of renewable generation, a more distributed generation profile, and a less carbon intensive energy supply—there is some indication that certain versions of this future may have negative impacts on energy system resilience.

In a recent review of the root cause of CAISO outages during the August 2020 heatwave, one of the three factors identified was:

> "*In transitioning to a reliable, clean and affordable resource mix, resource planning targets have not kept pace to lead to sufficient resources that can be relied upon to meet demand in the early evening hours. This makes balancing demand and supply more challenging. These challenges were amplified by the extreme heat storm.*"[42]

As the resilience of the gas system grows in importance, cost recovery mechanisms need to be developed to support investments in assets that strengthen resilience. These cost recovery mechanisms should define the resilience requirement for both gas and electric ratepayers.

5.1 Lessons from Others

This section details key lessons learned from recent regulatory and legislative activities governing resilience in the electric, water, and healthcare sectors. These lessons highlight some opportunities that may exist to develop regulatory structures to support gas resilience investments.

5.1.1 FERC Order 841, Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators

FERC Order 841,[43] issued in February 2018, directed regional grid operators to remove barriers to the participation of electric storage in wholesale markets. The order creates a legal framework for storage resources to operate in all wholesale electric markets and expands the universe of solutions that can compete to meet electric system needs. Order 841 was upheld in a federal appeals court decision in July 2020 that declared FERC has jurisdiction over how energy storage interacts with the interstate transmission markets it regulates, even if those energy systems are interconnected with state-regulated electric distribution grids.

> *By directing regional grid operators to establish rules that open capacity, energy, and ancillary services markets to energy storage, Order 841 affirms that storage resources must be compensated for all services provided and moves toward leveling the playing field for storage with other energy resources.*

A key component of the ruling is that "many participation models were designed for traditional generation resources—resulting in limitations or barriers to participation, which constrain competition,"[44] because novel resources technically capable of participating are precluded from doing so as they are forced to operate under participation models designed for existing

[42] CAISO. 2020. Preliminary Root Cause Analysis Mid-August 2020 Heat Storm.
[43] FERC. 2018. Order 841.
[44] US Court of Appeals. 2020. On Petitions for Review of Orders of the Federal Energy Regulatory Commission.

technologies. Energy storage resources (ESRs) such as batteries are especially affected by participation barriers because they have “unique physical and operational characteristics” distinct from traditional resources: ESRs can “both inject energy into the grid and receive energy from it.”

Although this order has limited direct applicability to the natural gas market, it does provide evidence that there are avenues to adapt the current market framework for valuable emerging technologies. Moreover, FERC Order 841 recognizes that the energy system is being used in a different way today than the current regulatory framework envisioned. The acknowledgment that the regulatory framework needs to be reconsidered to remove participation barriers supports the durability of the electric system.

5.1.2 FERC: ISO-NE, Cost-Recovery for Critical Infrastructure Protection (CIP)

Recent FERC orders approving cost recovery for CIP in the electric system showcase how the appropriate cost recovery mechanism can be designed. Federally mandated CIP requirements for electric systems assign protection standards at the low, medium, and high level, with higher standards carrying higher compliance costs. Left unresolved, however, was how generators in wholesale markets would recover the costs of compliance that cannot be competitively offered into the energy and capacity markets. This is because more stringent CIP requirements that result in higher compliance costs provide a disadvantage to a generator that is competing with a generator with lower compliance costs. In May 2020, FERC issued an order approving a proposal submitted by ISO-NE[45] to permit the recovery of incremental costs incurred when low-impact energy systems are reclassified as medium impact energy systems. The order permitted ISO-NE to allocate and collect those costs from transmission customers and disburse the funds to the pertinent facilities.

The concept behind CIP provides several lessons for the consideration of creating cost-recovery mechanisms to support resilience in the natural gas sector. The first is that there are examples in energy markets where resilience is legally mandated. Second, although these mandates can be a source of economic disadvantage to market participants in deregulated energy markets, FERC has approved RTO designed cost recovery mechanisms that socialize the costs.

FERC has mandated a set of protections for critical infrastructure in recognition of the vital role that the electric system plays in supporting the livelihoods of Americans and commerce in the US. The FERC CIP requirements can be viewed as a mandatory resilience requirement with a defined, measurable set of standards.

5.1.3 Energy Resilience in the Water Sector

Water utilities and their regulation offers key lessons on regulatory innovation and resilience. On September 13, 2008, Hurricane Ike made landfall on the upper Texas coast, causing significant damage. Millions of customers lost power, including 99% (more than 2.1 million) of CenterPoint Energy’s[46] customers. A critical pumping station that enables delivery of approximately 75% of Houston’s water supply was one of the casualties and was without power for approximately 10 days—Houston nearly had to declare a water emergency as a result.

[45] FERC. 2020. Docket No. ER20-739-002.

[46] CenterPoint Energy is the electric utility serving the Houston Area.

The Texas legislature enacted legislation[47] in 2015 mandating that water and wastewater treatment facilities have emergency backup power. The requirement also established a definition of resilience: duration at least equal to the longest power outage on record for the past 60 months, or at least 20 minutes, whichever is longer.

In addition, the America's Water Infrastructure Act (AWIA), passed by the US Congress in 2018 and reauthorized in May 2020, requires community water systems to conduct a risk and resilience assessment and develop an emergency response plan (ERP). The ERPs need to focus on more than merely being able to respond. They must include risk mitigation actions such as alternative source water, interconnections, redundancy improvements, asset hardening, and physical and cybersecurity countermeasures if and as justified through assessment. More specifically, the AWIA requires the following:

- Strategies and resources to improve the durability of the energy system, including physical security and cybersecurity.
- Plans and procedures that can be implemented, and identification of equipment that can be used, in the event of a malevolent act or natural hazard that threatens the ability of the community water system to deliver safe drinking water.
- Actions, procedures, and equipment that can obviate or significantly lessen the impact of a malevolent act or natural hazard on the public health and the safety and supply of drinking water provided to communities and individuals, including the development of alternative source water options, relocation of water intakes, and construction of flood protection barriers.
- Strategies that can be used to aid in the detection of malevolent acts or natural hazards that threaten the security or resilience of the energy system.

5.1.4 Energy Resilience in the Healthcare and Emergency Response Sectors

In 2012, Hurricane Sandy made landfall on the US coastline near Atlantic City, New Jersey, with winds upwards of 80 mph. The storm killed over 100 people, flooded coastal cities, destroyed structures, and tore down power lines. As the hurricane devastated the coast, 8.5 million people in 15 states lost power. The widespread power outages severely impacted medical facilities, leaving society's most vulnerable people in life-threatening situations.

Hospitals in New Jersey were forced to evacuate patients after floodwaters damaged backup generators needed to run elevators, lights, and ventilators. Transporting critically ill patients resulted in the loss of life and highlighted the need for more resilient solutions.[48] The total socioeconomic impact of Hurricane Sandy was also enormous, resulting in economic losses ranging from $27 billion to $52 billion.[49] According to the Executive Office of the President in

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[47] Texas Administrative Code. 2015. Rule 217.63: Emergency Provisions for Lift Stations.

[48] Modern Healthcare. 2012. *Left in the dark: Seven years after Katrina, Sandy is teaching hospitals more lessons on how to survive nature's fury*.

[49] Executive Office of the President. 2013. *Economic Benefits of Increasing Electric Grid Resilience to Weather Outages*.

2012, “these costs of outages took various forms including lost output and wages, spoiled inventory, delayed production, inconvenience and damage to the electric grid.”[50]

In response, legislation arose from the crisis. Assembly Bill 1561, the New Jersey Residents’ Power Protection Act,[51] was passed in 2015, which requires “medical facilities, pharmacies, first aid squads, fire stations, gas stations,’ and newly constructed grocery stores all have backup generators.” These generators are expected to run for 96 hours in case of emergency. Additionally, generators must activate within 10 seconds and be inspected weekly. [52]

Senate Bill No 854 was also approved after the storm. It mandates healthcare facilities and retirement homes install emergency electric power generation should the need arise.

New Jersey’s legislation focuses on investing in resilience and is impactful for the community and the economy. The legislation exemplifies the growing acceptance of the need for a resilient energy system. In the form of backup generation, the strength of the energy system can withstand shocks and protect vulnerable community members. It will mitigate the emergency costs hospitals face over time, “saving the economy billions of dollars and reducing the hardship experienced by millions of Americans when extreme weather strikes.”[53]

5.2 Key Opportunities

Across the gas delivery value chain, the use of existing infrastructure assets is shifting. This shift in usage will undermine the current and future economics of how assets are compensated and limit the development of resilience-focused assets.

- **High-pressure intrastate and interstate pipelines** are developed based upon long-term agreements supported by shippers. Shippers are contract counterparties who provide the economic framework for development of pipeline infrastructure assets. These shippers have historically derived economic value from projects using high load factor ratable forecasts. In the past decade, most material projects were supported by a combination of electric power generation projects or increasing demand from LDCs. Primarily, these have been FERC regulated assets and regulatory approval is based upon a demonstration of demand by the referenced shippers. As utilization of gas-fired generation shifts due to the advent of more renewables and utility demand moderates under decarbonization pressure, forecasted utilization is likely to be significantly lower. As the use of the gas system changes, the way gas service is charged needs to change as well.
- **Storage assets** provide significant resilience benefits. Some utilities have the benefit of on-system storage due to the geologic formations being within the operating jurisdiction or they use aboveground storage assets. Other utilities subscribe to services from storage owners and operators upstream of city gates. Historically, the economic drivers for storage were seasonal pricing differentials and balancing services provided to the integrated gas infrastructure system. In the future state, these assets will continue to provide seasonal and long-duration supply services. Storage is an important resilience asset and will continue to be essential to an integrated energy system. The economics of legacy seasonal pricing

[50] Executive Office of the President. 2013. *Economic Benefits of Increasing Electric Grid Resilience to Weather Outages*.

[51] State of New Jersey. 2014. *Assembly Bill No. 1561.*

[52] Facilities Net. 2013. *NFPA 110’s Fuel Requirements Can Help Guide Backup Power Plan For Hospitals*.

[53] Executive Office of the President. 2013. *Economic Benefits of Increasing Electric Grid Resilience to Weather Outages*.

differentials and balancing services may not provide sufficient revenue to encourage continued development and maintenance of these critical assets. If storage owners and developers were provided revenue for providing resilience benefits, however, the economic framework would sustain the availability of these necessary assets.

- **Distribution systems** have special duty assets including peak shaving storage, LNG storage, and non-pipeline solutions that provide resilience benefits. These assets historically have been designed to meet design day peak demand based upon historical heating degree days. However, as noted in the case studies, climate events create operating stress on existing gas systems. Like the interstate gas systems, the high frequency, high utilization economic framework that was used to justify investments in these legacy assets is not fit for stimulating future investments in a mix of assets that is becoming more intermittent.

The gas system is highly resilient and plays a critical role in supporting the stability of the overall energy system. Current regulatory, economic, and policy frameworks are not conducive to creating the vibrant energy system of the future. The gas and electric sectors are fortunate that the energy system designed to provide reliability has provided resilience benefits. However, the resilience benefits currently enjoyed are a regulatory byproduct and will not serve the needs of the future energy state.

6. Conclusions

The transformation of our energy system is well underway, driven by changes in the cost and availability of new technologies and increasing political and social pressure to decarbonize. The way energy is generated and used is changing rapidly, moving from a one-way power from centralized generation to end customers to a multidirectional network supporting two-way energy flows. As the energy system migrates to one increasingly powered by intermittent renewable sources, it also experiences increasingly frequent and intense climatic events—together these fundamental drivers are creating ever increasing operating stress on the energy system.

As discussed throughout this paper, the gas system is currently providing resilience benefits to the entire energy system. But, the strength of the current resilience is a byproduct of a regulatory environment that has valued investment in a reliable, ratable, and safe set of assets designed around a legacy demand forecast and historical heating degree day planning. As the transformation of the energy system continues, we anticipate a need to place a greater focus on resilience and a re-evaluation of the diversity of assets providing that service.

Full utilization of resilience assets is infrequent by nature. Yet, when a resilience service is demanded it is an essential product of the energy system and key to mitigating catastrophic risk and limiting socioeconomic costs to customers and communities. Utilities, system operators, regulators, and policymakers must make informed decisions to identify an economic framework to incent investments in resilience assets required to support a vibrant and strong future energy system. Resilience should be an energy system requirement like safety and not a byproduct of the existing framework.

6.1 Implications for Policymakers and Regulators

Looking into the future, evolving technology and the speed of transformation of the energy system will require a different economic and regulatory framework to support the appropriate mix of assets and fair compensation for continued investment. Achieving this is easier said than done. It will require a realignment of the valuation and cost recovery mechanisms that currently define the development of the US energy system.

Energy system resilience needs to be defined as a measurable and observable set of metrics, similar to how reliability is considered. To design a truly resilient system requires an ability to measure, evaluate, and optimize the benefit. Resilience needs to be considered as another dimension of system planning, similar to the way that reliability is considered today.

Resilience solutions must be considered from a fuel-neutral perspective and across utility jurisdictions, requiring electric, gas, and dual-fuel utilities to work together to determine optimal solutions. As this paper clearly illustrates through the case studies, when low likelihood, high impact events impact our energy system—the energy system responds through integrated responses that rely on fundamental characteristics of a diversity of assets. Energy system resilience solutions cannot be engineered through a siloed approach that considers only a portion of the energy system, they must consider the opportunity and value that can be brought to the energy system across a diversity of assets.

Methodologies need to be built for valuing resilience, such that it can be integrated into a standard cost-benefit analysis. Value must consider the avoided direct and indirect costs

to the service provider, customers, and society. LDCs and other pipeline infrastructure providers are not fully compensated for the true value of resilience services they provide to the overall energy system. Because the resilience of the gas system is largely a function of the reliability of the gas system, the true cost of resilience (i.e., return of and return on capital invested in physical infrastructure) is treated as a sunk cost. In other words, ratepayers are paying for reliability and enjoying resilience as a benefit—a disconnect that will become increasingly evident as extreme events become more frequent and the share of intermittent renewable generation increases.

In addition to the legacy evaluation criteria that determine cost-effectiveness, policymakers and regulators need to consider ways to evaluate the socioeconomic benefits and avoided costs to the communities resulting from a resilient energy system.

- What is the cost to the community of catastrophic loss of service during a climate event?
- If energy is not available to essential services can this value this be considered by analysis that primarily focuses on the costs per MMBtu or kWh?
- What level of insurance would these communities be willing to pay to have a future energy system that is robust enough to recover quickly and vibrantly from man-made and climate-driven events?

> *Resilience assets mitigate exposure to catastrophic impacts to the communities they serve and should be viewed as an insurance policy to limit risk.*

Cost recovery should be spread over the entire energy system when considering endorsement of capital projects for resilience assets. Further, cost recovery stimulated by utilization is not an appropriate metric for low load factor usage associated with low likelihood, high impact future scenarios.

6.2 A Call to Action

The development of a new regulatory framework will require innovation and collaboration from utilities, system operators, regulators, and policymakers to identify workable solutions that are fit for purpose and tailored to the requirements of regional markets. Preparing the future state to respond effectively to the current transformation requires the communication, coordination, cooperation and collaboration with all industry partners and stakeholders to identify, develop, and implement solutions.

Any future actions undertaken by regulators and other stakeholders should be evidence-based, fuel neutral, and based on objective criteria that scrutinized by all stakeholders. FERC has left it to the RTOs to assess how to best enhance the resilience of the power system and recognizes that solutions to improve gas/power resilience will need to be resolved at the RTO level, however federal direction may also be needed to coordinate productive discussion and facilitate collaboration.

Recent FERC regulatory activity and RTO-led stakeholder planning engagements indicates a precedent for this type of cross-industry collaboration. This activity suggests that the innovation required to address shifting requirements for energy system resilience and facilitate cost recovery for resilience assets is not only possible but achievable.

State PUCs have a vital role to play as well. As the primary regulator of LDCs, PUCs are charged with ensuring customer protection, fostering competition, and promoting high-quality infrastructure. Moreover, solutions to the issues identified in this report will require locally identified solutions that are tailored to the unique needs and circumstances of individual LDCs and the regions they serve.

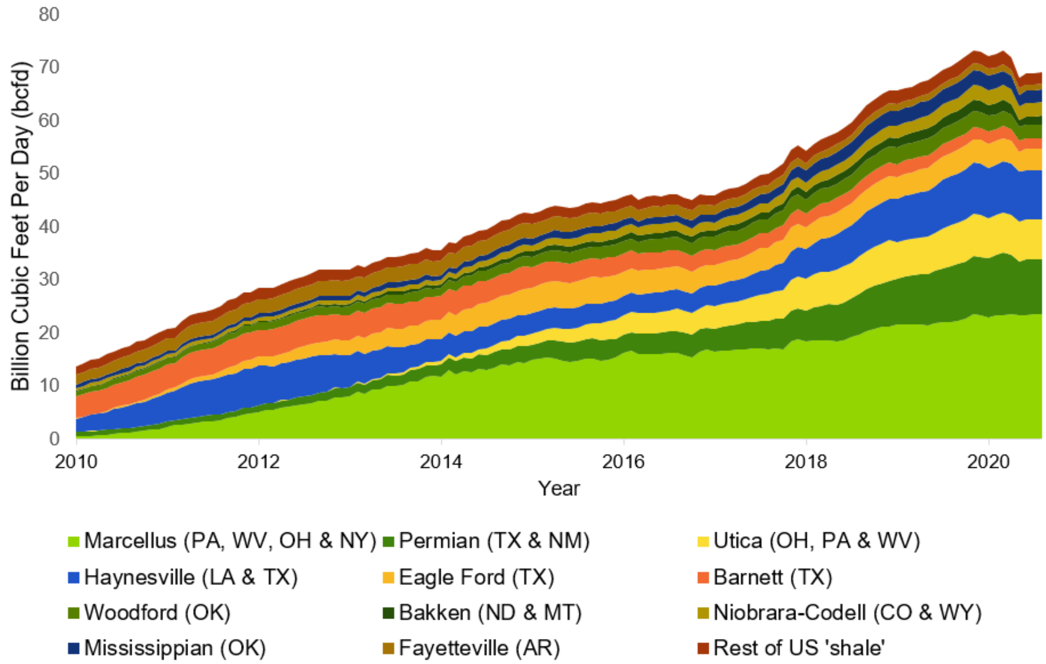
For energy system stakeholders at every level, resilience is not just a term that is currently in vogue, it is a characteristic that needs to be valued and engineered. Ensuring future energy system resilience will require careful assessments of all available solutions, maximizing the fundamental benefits of a diversity of assets. Utilities, system operators, regulators, and policymakers need new frameworks to consider resilience impacts as part of the energy system transformation, to ensure that resilience is not overlooked in the pursuit to achieve decarbonization goals.

Appendix A. The Natural Gas Value Chain

A.1 Production and Processing

Exploration and production companies explore, drill, and extract natural gas from geologic formations. In 2019, 81% of production came from shale.[66] Production from these formations has grown rapidly over the past decade, as Figure A-1 shows.

Figure A-1. US Dry Shale Gas Production, 2010-2020



Source: Guidehouse, US Energy Information Administration

Once produced and extracted, gathering pipelines transport natural gas to processing facilities where impurities are removed, resulting in pipeline-quality natural gas. Gathering systems use compressors to move gas through the midstream pipelines. Most compressors are fueled by natural gas from their own lines. This self-reliance increases resilience by allowing the movement of molecules without dependency on other fuel sources.

A.2 Transmission

From the gathering system, natural gas moves into the high-pressure transmission system for long-haul transportation to market centers. These pipelines efficiently move large amounts of natural gas thousands of miles.[54] In the US, there are approximately 3 million miles of mainline and other pipelines that connect gas production with consumption.[55] Over 30 companies in North America own and operate interstate pipelines, which the FERC regulates. Intrastate pipelines are generally owned by publicly traded entities and are regulated by the states in which they are located.

[54] American Gas Association. *How Does the Natural Gas Delivery System Work?*. Accessed October 2020.
[55] EIA. *Natural Gas Explained: Natural Gas Pipelines*. Accessed October 2020.

A.2.1 Compressor Stations

The pressure of gas in each section of the transmission system ranges from 200 psi to 1,500 psi, depending on where the pipeline operates. Compressor stations are located approximately every 50 to 60 miles along transmission pipelines to regulate pressure and keep gas moving.

A.2.2 Gas Storage

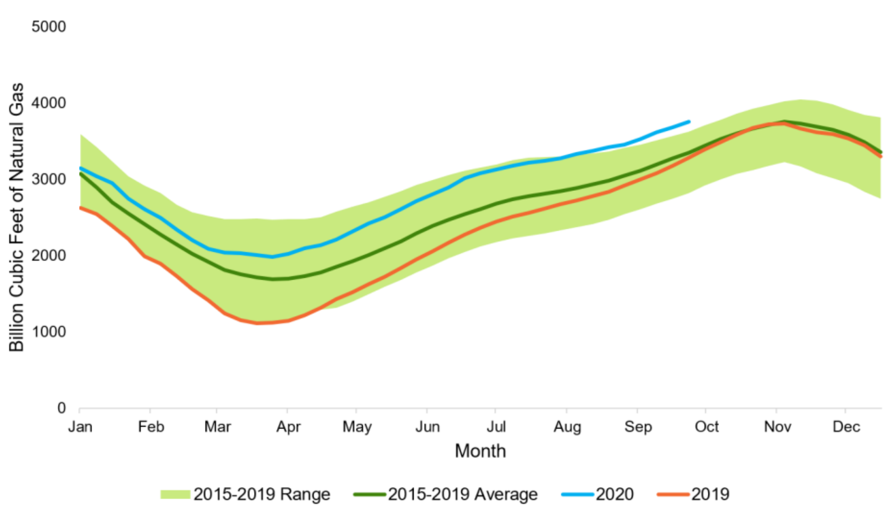
Storage capacity enables the delivery of reliable gas service to consumers and end-users throughout the year. While natural gas production remains relatively constant year-round, storage enables gas providers to adjust to daily and seasonal demand fluctuations (Figure A-2).

Storage can be owned or operated by natural gas transmission companies or LDCs. Off-system storage is not directly tied to a natural gas utility's distribution system, but that is accessible via the transmission system. Most off-system storage is underground; however, there are examples of aboveground off-system storage. Underground storage facilities can be developed from depleted gas reservoirs, aquifers, or salt caverns and are connected to one or more transmission pipelines; whereas aboveground storage is often provided through LNG or CNG.

In addition to offering storage services, some pipeline companies may provide a park and loan that enables shippers to borrow or lend gas. These services are typically used to balance daily or intraday markets. Some Pipelines also offer tariff-based delivery services called No Notice, which allows an LDC to receive gas at variable quantities throughout the day without placing nominations to the provider. These no-notice services are backed by storage and pipeline delivery assets.

In the lower 48 states, it is common for the gas system to have at least 2,000 Bcf to 3,000 Bcf of working natural gas in underground storage, as Figure A-2 shows. The entire US commercial sector consumed 3,500 Bcf in 2019. Base gas (or cushion gas) is the volume of natural gas intended as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates throughout the withdrawal season. Working gas is the volume of gas in the reservoir above the level of base gas. Base gas inventories remain relatively steady at approximately 4,300 Bcf throughout the year.

Figure A-2. Working Gas in Underground Storage, Lower 48 States



Source: Guidehouse, US Energy Information Administration

A.2.3 City Gate Stations

Natural gas typically passes through a city gate to move from the transmission pipeline to the pipelines under operational control of LDCs. At the city gate, the pressure is reduced from transmission to distribution levels, an odorant is added, if not already provided by the upstream pipeline, and incoming flow is measured to ensure it matches the LDC's distribution requirements. Deliveries from transmission pipelines are normally scheduled a day or more prior to delivery and include the estimated total quantities for demand in the day forward. Some transmission systems provide operators the ability to make intraday changes to nominations in attempt to sync scheduled demand with actual demand.

In addition, pipeline midstream companies and inter-connection pipelines (i.e., LDC or other midstream pipeline companies) have OBAs in place in which parties agree to specified procedures for balancing between nominated levels of service and actual quantities transferred between the two pipelines.

A.3 Distribution

After leaving the city gate, natural gas moves into distribution pipelines. Each distribution system has sections that operate at different pressures, with mechanical regulators controlling the pressure to optimize efficiency. Generally, the closer natural gas gets to a customer, the lower the pressure.

Many distribution systems also feature on-system storage. This is typically aboveground and includes small-scale LNG or CNG storage that enables the distribution company to meet short-term requirements for increased gas demand and pressure balancing needs. Such facilities enable LDCs to supplement, or shave, the amount of natural gas needed from external suppliers through on-system resources. Some distribution systems also feature underground storage.

A.3.1 Customer Delivery

As gas travels through the main lines of the distribution system, it is routed to customers through smaller service lines. Flow meters and mechanical regulators reduce the pressure to under 0.25 psi, the normal pressure for gas within a household, equivalent to less pressure than a child blowing bubbles through a straw.

The types of customers served by the system include the following:

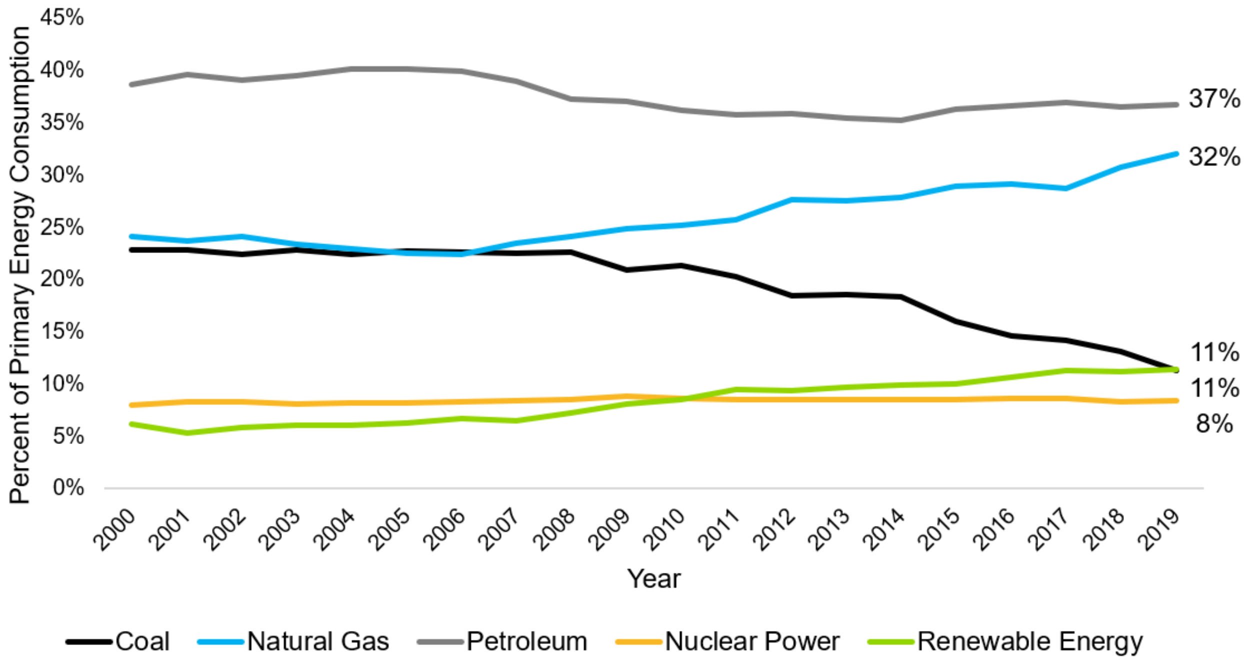
- **Interruptible vs. Firm Demand:** Interruptible customers are often large commercial or industrial customers that have selected to contract for natural gas service that can be interrupted when the delivery system is experiencing constraints. When a natural gas utility experiences a situation where gas consumption exceeds demand, such as during a peak heating day, system operators can curtail these interruptible customers while maintaining service to firm demand (or uninterruptible) customers.
- **Ratable vs Non-Ratable Flow:** Ratable flow refers to customers that will be delivered one-twenty-fourth of their nominated and scheduled daily quantity every hour—they receive the same amount of natural gas every hour of every day. Non-ratable flow refers to customers that receive uneven or varying consumption throughout the day.

Appendix B. The Current State of US Gas Consumption and Production

The US natural gas industry is larger today than ever before—gas consumption and production have grown since the 1950s and are currently at record levels. In 2019, the US consumed 31 trillion cubic feet of natural gas. Concurrently, the US produced approximately 33 trillion cubic feet of natural gas (dry production) in 2019.[56]

In 2019, natural gas accounted for 32% of US primary energy consumption.[57,58] Natural gas has been accounting for an increasing portion of the energy consumed in the US since 2000, as Figure B-1 illustrates.

Figure B-1. US Primary Energy Consumption by Source



Source: Guidehouse, US Energy Information Administration

B.1 Gas Consumption by Customer Segment

Natural gas is a significant energy source used to generate electricity in the electric sector and meet the end-use heating demands in the residential, commercial, and industrial sectors. It is also used in distributed electric power generation primarily through CHP in the industrial sector and as a transportation energy source.

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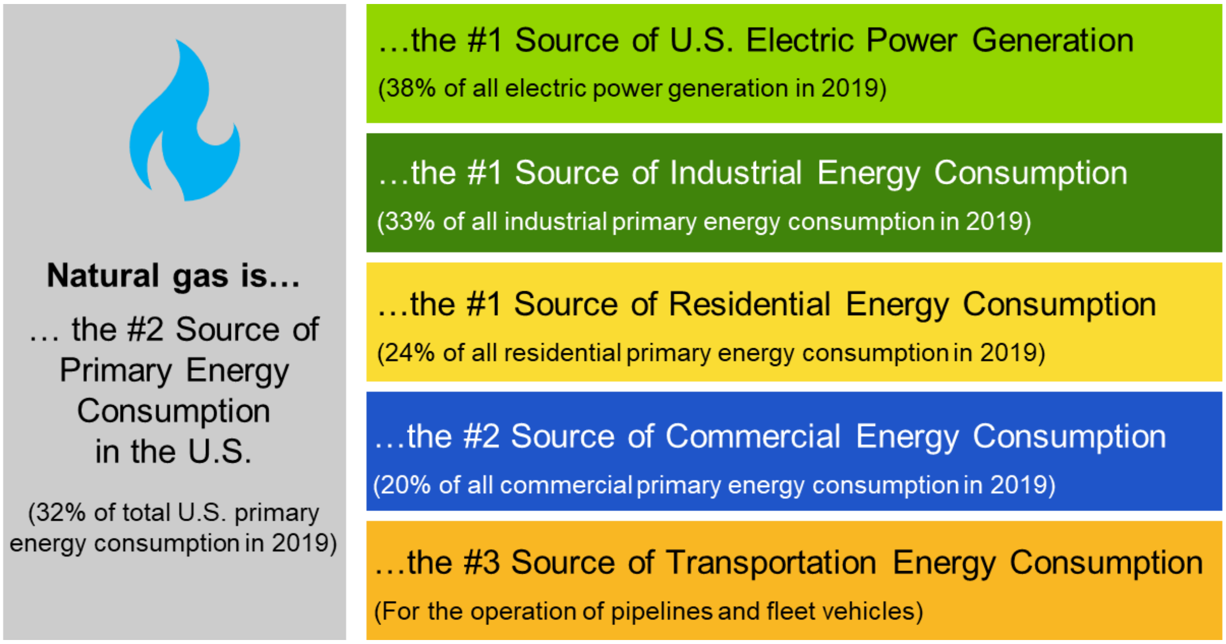
[56] EIA. 2020. *Annual Energy Outlook*.

[57] Primary energy consumption is a measure of total energy demand, covering the consumption of fossil fuels by end users like homes and businesses, the energy used to produce electricity, and losses during the transformation and distribution of energy.

[58] EIA. 2020. *Annual Energy Outlook*.

Figure B-2 illustrates the role that natural gas plays in powering each of these sectors. Natural gas supply is also detailed further throughout the remainder of this section.

Figure B-2. Natural Gas Deliveries and Consumption by Sector



Source: Guidehouse, US Energy Information Administration

B.1.1 Electric Power Generation

Growth in shale gas production has led to a decline in natural gas prices and has contributed to steady growth in the amount of electric power generated by natural gas (Figure B-3).

> *In 2019, 6,025 utility-scale gas generation facilities produced 38% of total US electricity, the largest share of any individual source. This is up from 5,722 gas generation facilities producing 33% of total US electricity in 2016.*[59]

The price of natural gas is a key driver behind its growth as a source of electricity production. This trend continues today, with the 2025 EIA outlook for the levelized cost of electricity of next-generation coal plants hovering around $76/MWh, and combined cycle natural gas plants around $38/MWh. This is in-line with EIA projections for non-dispatchable technologies such as onshore wind ($40/MWh) and solar PV ($33/MWh), and cheaper than projections for offshore wind ($122/MWh) and hydroelectric ($53/MWh).[60]

Grid operators find value in gas-fired electric power generation because of its flexibility as an energy resource, serving as both high capacity factor baseload and dispatchable generation. The fast ramp-up and ramp-down times of natural gas generators are especially important in regions with a large share of renewables generation where natural gas plants are often required to balance the steep increase and decrease in generation capacity.

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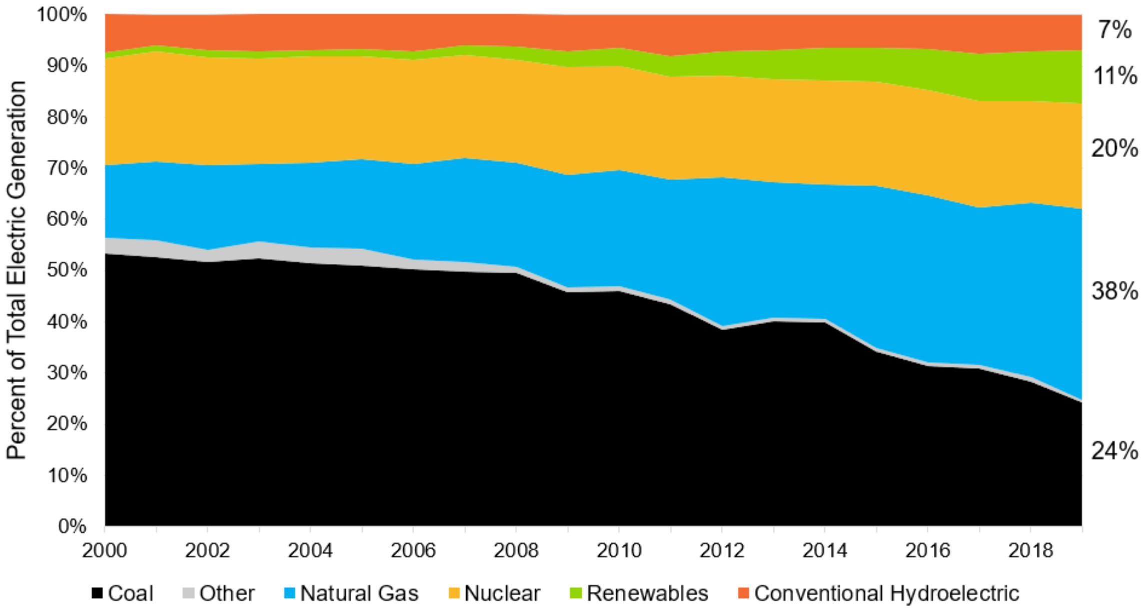
[59] EIA. 2020. *Preliminary Monthly Electric Generator Inventory, September 2020*.

[60] EIA. 2020. *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2020.*

Figure B-3. Net Electric Power Generation by Source, 2000-2019



Source: Guidehouse, US Energy Information Administration

B.1.2 Industrial

Natural gas is critical to meeting the energy needs of the industrial sector. In 2019, the industrial sector accounted for 33% of total US natural gas consumption, which in turn accounted for 33% of the industrial sector's total energy consumption.[61]

Within the industrial sector, natural gas supports a wide range of uses including building heating, a feedstock for CHP, and as a feedstock for high energy-intense processes such as the production of chemicals, fertilizer, and steel.

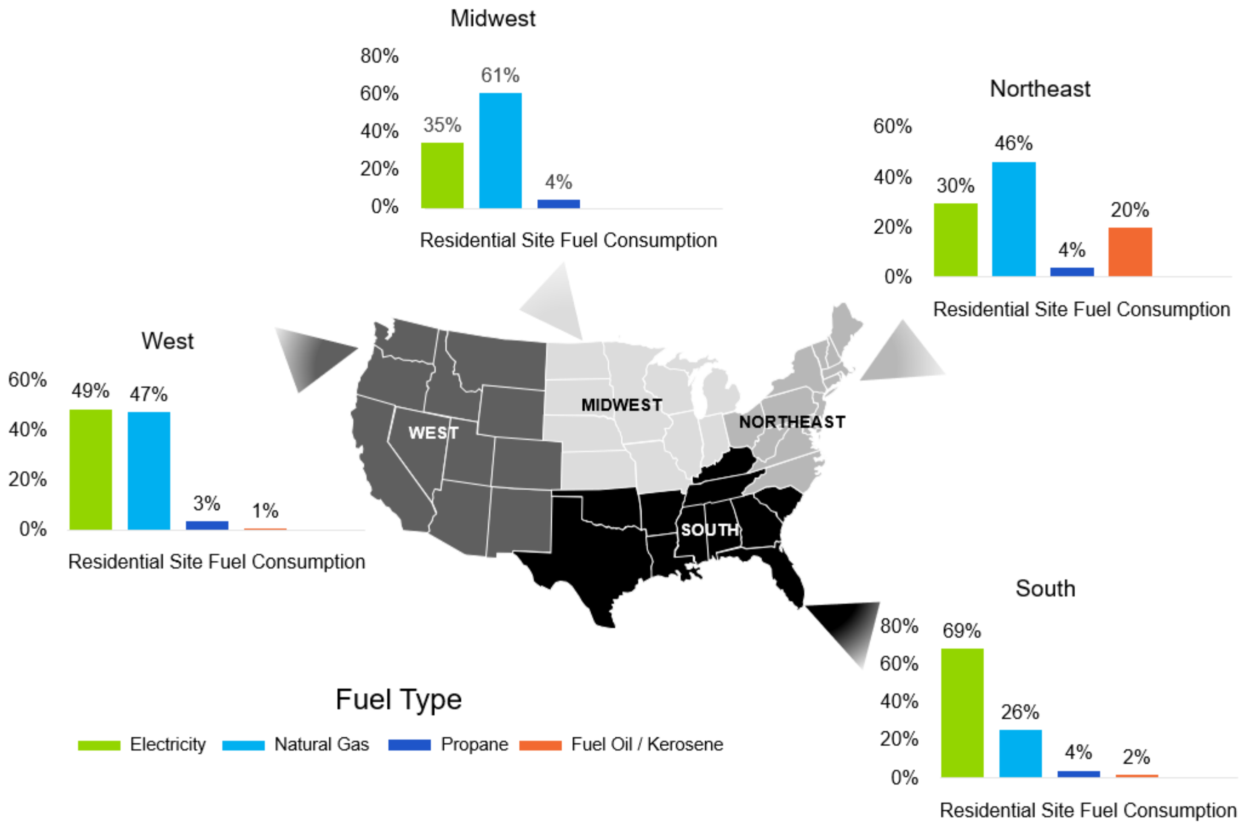
B.1.3 Residential

In the US residential sector, natural gas is used to heat homes and water, cook, and dry clothes. Although the use of natural gas varies by geography (as Figure B-4 illustrates), about half of the homes in the US use it for space and water heating. In 2019, the residential sector accounted for approximately 16% of total US natural gas consumption, which translates to 24% of the residential sector's total primary energy consumption.[62]

[61] EIA. *Natural gas explained: Use of natural gas*. Accessed September 2020.

[62] EIA. 2020. *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2020.*

Figure B-4. Natural Gas Share of Total Residential Energy Consumption, 2015



Source: Guidehouse, US Energy Information Administration

B.1.4 Commercial

In the US commercial sector, natural gas is primarily used to heat buildings and water, to operate refrigeration and HVAC equipment, to cook, dry clothes, and provide outdoor lighting and heating. In 2019, the commercial sector accounted for approximately 11% of the total US natural gas consumption, which translates to 20% of the commercial sector's total primary energy consumption.[63]

B.1.5 Transportation

Natural gas plays a niche role in the US transportation sector, accounting for only 3% of the sector's total energy needs in 2019. Within the transportation sector, natural gas is used to operate compressors to move natural gas through pipelines and as a vehicle fuel in the form of CNG and LNG.

Most vehicles that use natural gas as a fuel are government and commercial fleet vehicles. CNG medium duty vehicles have gained increasing popularity over diesel due to lower prices and clean air benefits. In 2018, there were a total of 19,151 CNG public transit busses nationwide, compared to 32,671 diesel and 13,872 hybrid busses.[64] In 2020, there are 1,677

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[63] EIA. 2020. *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2020.*

[64] DOE. *Alternative Fuels Data Center, Transit Buses by Fuel Type*. Accessed October 2020.

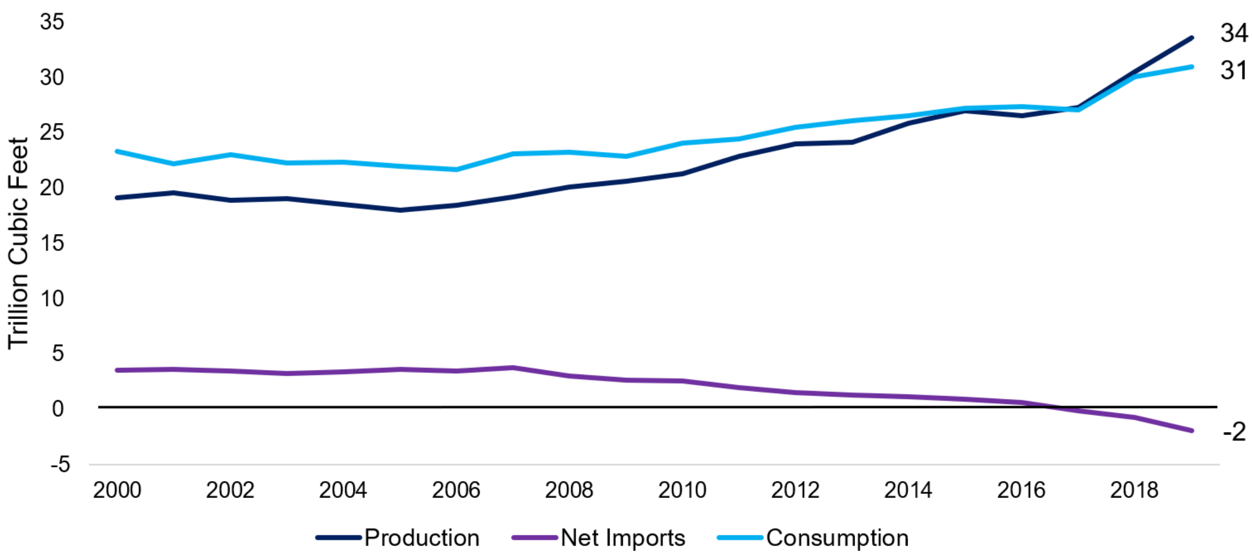
CNG and LNG refueling sites in the US compared to 29,738 EV stations. However, this infrastructure supports decarbonization of heavy and medium to light duty vehicles where EV infrastructure primarily supports light duty vehicles.[65]

B.2 US Gas Production

US natural gas production continues to grow; domestic production has exceeded consumption since 2017. The US now produces nearly all the gas it consumes, decreasing its reliance on imports from other countries. In large part due to accessible shale formations, most natural gas (97%) is produced onshore in a diversified base of over 30 states. Five states (Texas, Pennsylvania, Oklahoma, Louisiana, and Ohio) account for approximately 70% of the US total dry natural gas production.[66]

In 2019, 34 trillion cubic feet of natural gas was produced (Figure B-5).[67] Increased domestic production has contributed to a decline in prices, which has led to the significant increase in natural gas consumption across sectors, primarily in the electric power generation and industrial sectors.

Figure B-5. US Natural Gas Consumption, Dry Production, and Net Imports, 2000-2019



Source: Guidehouse, US Energy Information Administration

B.3 Low Carbon Gas Production

Since the early 2000s, US energy-related GHG emissions have been decreasing.[68] A significant driver of the emissions reduction has been a transition from higher-emissions fuels (e.g. coal) to natural gas. This transition is expected to continue, as natural gas supply is further decarbonized through the increase in low carbon gas production.

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[65] Oak Ridge National Laboratory. 2020. *Transportation Energy Data Book Edition 38, Table 6.12.*

[66] EIA. *Natural Gas Explained: Where our natural gas comes from*. Accessed October 2020.

[67] EIA. *U.S. Energy facts explained*. Accessed October 2020.

[68] EIA, *EIA Projects U.S. Energy-Related CO2 Emissions Will Remain Near Current Level Through 2050.*

Fueled by city and state commitments to decarbonize, investors are driving the capital necessary for companies to invest in the further research, development, and production of low carbon gases such as RNG, hydrogen-enriched natural gas, and hydrogen. Meanwhile, political and regulatory agencies are clearing the path for the growth of this low carbon gas development. Although low carbon gas production is nascent in the US, its growth potential provides a pathway for the natural gas industry to meet energy sector decarbonization goals. It also increases the resilience of the energy system by providing a locally sourced supply of clean energy.

B.3.1 Biogas

Biogas is produced primarily through landfill gas collection, thermal gasification, or anaerobic digestion of waste feedstocks from the sewage, agriculture, food, and forestry sectors. Biogas can be used to produce heat and electricity, or it can be further processed to remove impurities to meet the standards of conventional natural gas (defined as RNG) for distribution through the gas pipeline system, as Figure B-6 illustrates. Though most RNG produced is consumed onsite for electric power generation or heating, the American Gas Foundation found that there will be about 50 trillion Btu of RNG produced in the US for pipeline injection in 2020, a number that has grown at a compound annual growth rate (CAGR) of 30% over the past 5 years.[69]

> *The number of renewable natural gas (RNG) production facilities in North America grew by 145% from 2014 to 2019.*[70]

There are over 2,200 biogas production sites in the US. Investments into new biogas systems totaled $1 billion in 2018, a number that has been growing at a CAGR of 12%.[71] In 2019, the US produced approximately 230 billion cubic feet of biogas primarily from solid waste (83%), industrial (6%), wastewater (6.5%), and agricultural (4.5%) feedstocks.[72]

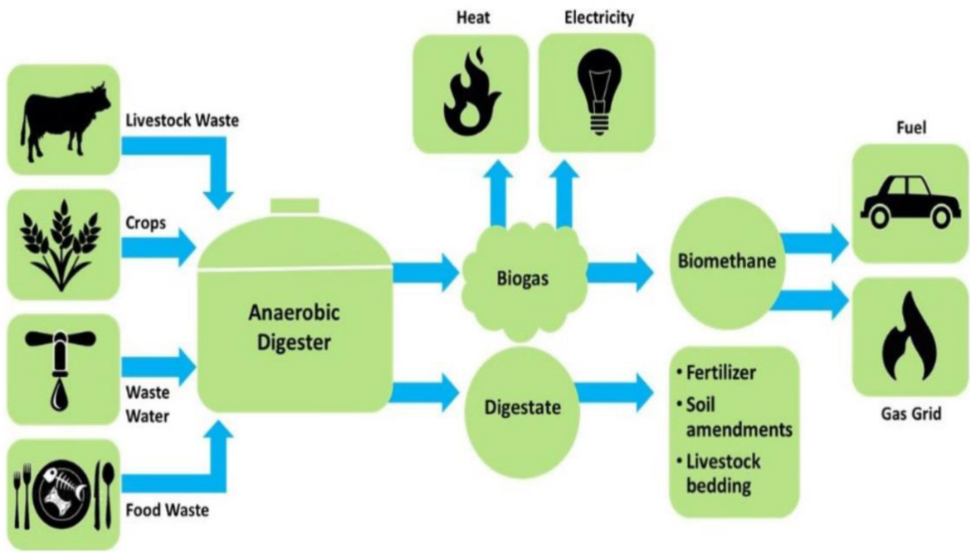
[69] American Gas Foundation. 2019. *Renewable Source of Natural Gas: Supply and Emissions Reduction Assessment.* Accessed October 2020.

[70] Coalition for Renewable Natural Gas. 2019. *Renewable Natural Gas Market Surpasses 100-Project Pinnacle in North America*. Accessed October 2020.

[71] American Biogas Council. 2019. *Why Biogas?*.

[72] Guidehouse Insights. 2020. *Renewable Natural Gas: Overview of the Current State of Biogas and Renewable Gas Markets*.

Figure B-6. Low Carbon Gas Production Through Anaerobic Digestion

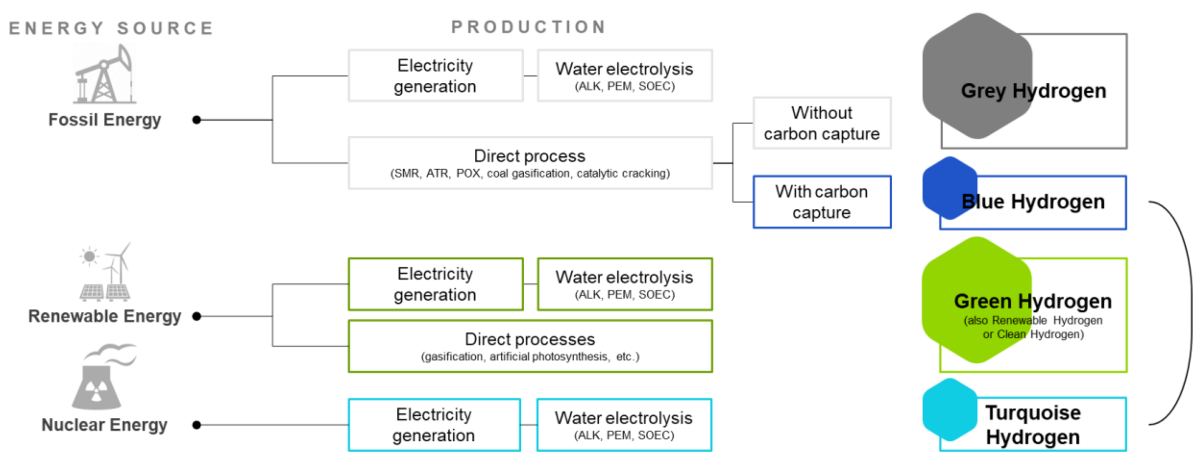


Source: Environmental and Energy Study Institute

B.3.2 Hydrogen

Hydrogen is produced through electrolysis, a splitting of water atoms into their component parts of hydrogen and oxygen. Producing hydrogen requires an input of energy, the type of energy that is used defines the carbon intensity of the process and ultimately whether it is considered low carbon. Figure B-7 describes the various types of hydrogen across a color spectrum (grey, blue, green, and turquoise hydrogen).

Figure B-7. Hydrogen Production Technologies



Source: Guidehouse

Steam methane reforming is used to form most hydrogen production. Hydrogen is often produced for use alongside its two largest consuming sectors, petroleum refining and fertilizer production. There are1,600 miles of hydrogen pipeline in the US, and most states have a large hydrogen production facility producing approximately 10 million metric tons of hydrogen annually.[73] However, a recent California Energy Commission study estimates that with market and policy action to facilitate scale-up of production capacity, California alone could produce an excess of 2,000 metric tons per day by 2030.[74]

[73] U.S. Office of Energy Efficiency & Renewable Energy. 2019. *10 Things You Might Now Know About Hydrogen and Fuel Cells*.
[74] California Energy Commission. 2020. *Roadmap for the Deployment and Buildout of Renewable Hydrogen Production Plants in California*.