

Under Pressure: Gas Utility Regulation for a Time of Transition

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MAY 2021

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Suggested citation

Anderson, M., LeBel, M., & Dupuy, M. (2021, May). *Under pressure: Gas utility regulation for a time of transition*. Regulatory Assistance Project.

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Authors and Acknowledgments

Megan Anderson and Mark LeBel are associates and Max Dupuy is a principal at the Regulatory Assistance Project.

Donna Brutkoski and Ruth Hare of RAP provided editorial assistance.

The authors would like to express their appreciation to the following people who provided helpful insights into drafts of this paper:

Sara Baldwin, Energy Innovation: Policy and Technology LLC

Sherri Billimoria, RMI

Richard Cowart, David Farnsworth, Ann McCabe, Jan Rosenow, Louise Sunderland and Rich Sedano, RAP

Mike Florio, Gridworks

Megan Gilman, Colorado Public Utilities Commission

Brian Jones, MJB&A, an ERM Group Company

Jim Lazar, Institute for Energy Democracy, Pace Energy and Climate Center

Ric O'Connell, GridLab

John Rhodes, formerly of the New York Public Service Commission

Rebecca Tepper, Energy and Environment Bureau, Massachusetts Attorney General's Office

External review does not mean agreement with all of the paper's content and recommendations.

Abbreviations

Btu	British thermal unit(s)	LDC.	local distribution company
CIAC	contribution in aid of construction	LMI	low- and moderate-income
EERS	energy efficiency resource standard	NPA.	non-pipeline alternative
FERC	Federal Energy Regulatory Commission	O&M.	operation and maintenance
GHG	greenhouse gas	RPC	revenue per customer
IRP	integrated resource plan/planning		

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Executive Summary

The way we use fossil gas as a fuel for heating buildings and other end uses is rapidly changing. Efficiency gains and improved electric end-use technologies are constraining demand for gas. The urgency to address climate change is increasing, with the new U.S. national target to cut greenhouse gas emissions by more than half by 2030 adding to existing state-level decarbonization policies. Increased awareness of the health and safety risks of fossil gas is also accelerating the transition to other sources of energy. These shifts are happening as gas utility distribution systems in many places are aging — meaning that utilities may be seeking approval for major investments while the size of their customer base is poised to shrink. Regulators and utilities that do not get ahead of these trends may face the need to impose unsustainable rate increases on customers, meaning high costs for those who can least afford it.

These changes mean that the current paradigm for gas utility regulation is coming under pressure. The good news is that preparing for the gas transition does not require inventing new regulatory mechanisms. Regulators can start with existing tools to anticipate changing circumstances and create paths to meet customer needs. Planning processes, efficiency and electrification programs, and rate-making reforms can all be deployed to manage the risks to consumers, utilities and the economy at large.

Preparing for the gas transition does not require inventing new regulatory mechanisms. Regulators can start with existing tools to anticipate changing circumstances and create paths to meet customer needs.

Building Blocks for a Changing Regulatory Framework

Our recommendations, summarized on the next page, offer a range of practical options for utility regulators to consider as they confront changing circumstances in gas regulation and risks to gas customers. Utility regulators may choose to use one or many of these strategies to build on their understanding of gas systems in their state, unlock cost savings and other benefits, and increase awareness of changes or evolving demands on the system. These recommendations can serve as building blocks to create a regulatory framework to facilitate the gas transition in a manner that is efficient and equitable.

The Road Ahead

Beyond reforms that are within the current powers of utility regulators, policymakers should start to consider whether broader structural changes will be necessary. These policies may require statutory changes to implement, such as new sources of funding for transition assistance and more fundamental changes to the structure of investor-owned gas utilities.

Strategies for Regulators Addressing the Gas Transition



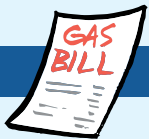
Revitalize Gas Utility Planning

- Set a solid foundation with a **robust and inclusive stakeholder process**, an outline of relevant goals and policies, and coordination with other planning efforts.
- Have the gas utility create a layered **system map** that illustrates and describes the current system, including existing infrastructure and its condition, customer base, and demand and supply.
- Require the development of **alternative scenarios** for meeting demand; analyze the scenarios for reliability, safety, cost, carbon impact, risk and resiliency; and consider other key transition issues.
- Create a short-term action plan and a **long-term transition plan**.



Enhance Energy Efficiency and Electrification Programs

- **Remove barriers to electrification** within energy efficiency program rules, such as prohibitions on fuel switching.
- **Expand and coordinate** energy efficiency and electrification programs to reduce costs and improve equity.
- Develop an approach for evaluating and implementing **non-pipeline alternatives**.
- Implement **geographic targeting of full-building electrification** as part of a gas distribution network transition strategy.



Reform Gas Rate-Making

- **Pay down rate base and lower the risk** of rate impacts.
 - Require **additional investment from new customers** for any gas system expansions.
 - **Accelerate depreciation timelines** for long-lived gas system assets.
- Update cost allocation and rate design to ensure **equitable and efficient outcomes**.
 - Abandon archaic minimum system analyses and adopt **flexible time-based allocation methods** for shared gas system costs.
 - Implement **rate designs that improve efficiency, while prioritizing affordable bills** for low-income customers.
- Better **align utility incentives** with customer objectives and public policy goals.
 - Adopt **decoupling methods that use overall revenue targets**, not revenue-per-customer targets.
 - Explore **performance-based rate-making** improvements to deemphasize capital investments and incentivize customer objectives and public policy outcomes.

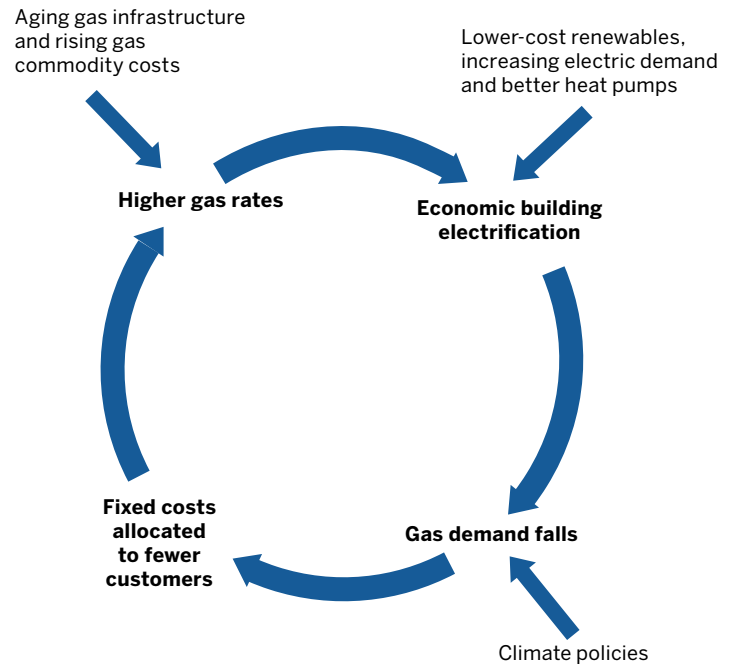
I. Introduction

The current paradigm for gas utility regulation is coming under pressure. Global energy systems are in a period of rapid transition. Utilities are rethinking how they deliver energy to customers, while technology is changing how we power our heating, cooling, cooking and other commercial and industrial needs. With these changes, we will see both increased integration of our energy systems and the need for thoughtful consideration of how to address the unique factors driving the transition in each of these sectors: buildings, transportation and industry.

As we reexamine how to meet the energy needs of customers most efficiently, the role of the gas system in meeting those needs will change. Several issues and trends point to the need for this transition:

- More efficient gas appliances and tighter building shells are lowering per-customer demand and gas throughput, changing the cost-effectiveness of typical gas delivery infrastructure.
- Electric end-use equipment, such as heat pumps and induction cooktops, is declining in price, increasing in efficiency and improving in quality and provides valuable flexibility benefits to the electric grid.
- Increasingly stringent economywide greenhouse gas (GHG) emissions policies require significant reductions in the combustion of fossil gas.
- Greater awareness of the safety and public health risks caused by fossil gas, from extraction to its use in homes, is raising levels of consumer concern.
- Alternative gases with potentially lower GHG impacts, such as renewable methane or green hydrogen, face significant economic hurdles. They also do not necessarily address key environmental, health and safety concerns, though they may be well suited to some hard-to-electrify sectors.

Figure 1. Factors creating a need for gas system transition



Source: Aas, D., Mahone, A., Subin, Z., Mac Kinnon, M., Lane, B., & Price, S. (2020). *The Challenge of Retail Gas in California's Low-Carbon Future: Technology Options, Customer Costs, and Public Health Benefits of Reducing Natural Gas Use*

- Continued investment to maintain, replace or add gas infrastructure may cause substantial rate increases for customers, particularly if that investment is coupled with a decrease in gas throughput.

Figure 1 illustrates how these factors combine to put pressure on the current gas system.¹

Many of the issues leading to a shift in the role of the gas system require coordinated attention and integrated efforts by all levels of government — local, state, federal and even international treaties — to build a modern energy system. State utility regulators can contribute to this work by reexamining the regulatory framework for gas utilities, also known as gas local distribution companies (LDCs), to facilitate a transition.²

1 Aas, D., Mahone, A., Subin, Z., Mac Kinnon, M., Lane, B., & Price, S. (2020). *The challenge of retail gas in California's low-carbon future: Technology options, customer costs, and public health benefits of reducing natural gas use*, p. 6. California Energy Commission. <https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/index.html>

2 This report focuses on regulation of gas utilities providing service for gas end uses on the distribution system and not on the use of gas as a fuel for electric generating stations.

Making equity integral to addressing a changing gas system

Regulators will need to take deliberate steps to ensure that changes to the gas system will not disproportionately affect low- and moderate-income (LMI) communities and customers. Throughout this paper, we recommend ways in which regulators might integrate these considerations into planning, programs and rate design. Here, we highlight several recommendations.

Planning

- Create robust and inclusive stakeholder processes to ensure that the voices of disadvantaged communities are being heard and their long-term needs are being met.
- Consider how targeted electrification may allow LMI customers to benefit from a lower energy burden.

Programs

- Expand weatherization and other energy efficiency

programs and orient programs toward low-income and disadvantaged communities to decrease energy burden and improve home resiliency.

- Develop incentives and dedicated programs for LMI electrification and ensure that those programs are known and accessible to LMI customers.

Rate-making

- Consider methods to lower rate base to avoid increases in rates that may affect customers remaining on a shrinking gas system.
- Look at customer class distinctions and analytical methods to ensure that costs are allocated efficiently and fairly.
- Design rates to ensure that low-income gas heating customers are not unfairly penalized throughout the transition.

Regulators can then anticipate new conditions and incorporate them into solutions, rather than leaving them to become challenges to meeting customer end uses.

In this report, we recommend and outline tools that regulators can use to refresh regulation of gas utilities ahead of coming changes. Our recommendations fall into three broad categories:

1. Revitalize **planning** efforts to ensure that regulators and utilities alike have the information they need to address new needs and attendant system changes, to avoid unnecessary gas system investments, and to meet the energy needs of all consumers equitably.
2. Enhance parallel **programs** that increase energy efficiency and electrification to ensure that modern technologies can be adopted in an efficient, affordable and equitable manner.
3. Revisit and reform **rate-making** to align changing circumstances with desired outcomes, by lowering the risk of long-term rate impacts, ensuring that customer rates are equitable and efficient, and removing incentives that obstruct utilities' willingness to consider reform.

Within each of these overarching recommendations, we include more specific tools from which regulators can choose to fit their current regulatory regimes and the particular circumstances in their states. Throughout this transition, regulators can ensure that the safety and reliability of the gas system is maintained, disadvantaged communities are supported, and no one loses crucial energy services.

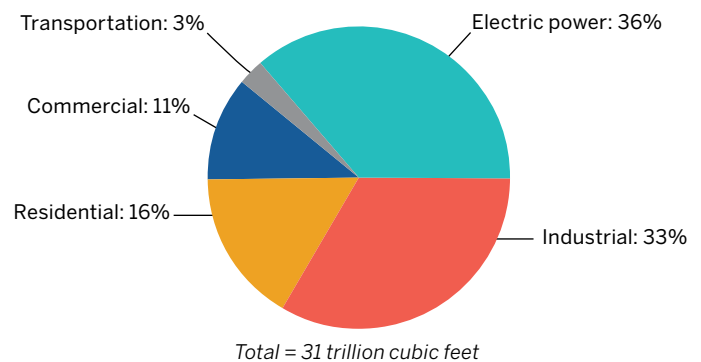
By recognizing and considering the coming challenges now, regulators and other policymakers can ensure that they are in a position to develop solutions that will result in a system that meets end uses more efficiently and equitably and in a manner consistent with carbon reduction policies. Conversely, if regulators delay, they will miss opportunities to design optimized solutions and will be facing a much more difficult challenge in coming decades. The tools outlined in this paper — planning, program design and rate-making — are not new to regulators but are powerful means to address a changing landscape.

II. Issues and Trends Affecting Gas Utilities

Since the middle of the 20th century, fossil methane extracted from the earth — one of several different fossil gases³ — has become one of the most prevalent energy sources in the United States. Gas utilities typically receive this gas through interstate transmission pipelines and then distribute it to about 70 million residential customers⁴ and 5.7 million commercial and industrial customers⁵ for space heating, water heating, cooking and other applications. Currently, the United States has 3 million miles of gas distribution and transmission pipeline, a combined length roughly equivalent to pipeline circumnavigating Earth 120 times, and is expanding by about 10,000 miles per year.⁶ The age and makeup of the gas pipeline system varies, but in some areas, it is more than 100 years old.⁷ In 2019, the industrial, commercial, residential and transportation sectors accounted for about two-thirds of the fossil methane gas consumption in the United States (see Figure 2).⁸

In an appendix to this report, we examine in more detail the history of the fossil gas system, technical basics

Figure 2. 2019 U.S. natural gas consumption by sector



Source: U.S. Energy Information Administration. (2020, November 30). *Natural Gas Explained: Use of Natural Gas*

of its operation and how its regulatory framework was built throughout the 20th century. But in the 21st century, the landscape in which gas utilities are operating is rapidly changing. In this section of our report, we identify six interrelated issues that will put existing utility practices and regulations under pressure.

3 The different kinds of gas that can provide energy services include methane, propane, butane, hydrogen and other heavier gases. Each of these gases can come from different sources or methods of creation. Throughout this paper, we use the term “fossil methane” where appropriate or more generally “fossil gas” for gases that are extracted from the ground or otherwise derived from another fossil fuel. When these gases are combusted, GHG emissions (primarily carbon dioxide) are a byproduct, as well as nitrogen oxides, carbon monoxide, formaldehyde and particulate matter, all of which can be hazardous to human health. Methane itself is also a potent greenhouse gas, and any percentage of methane that is not combusted (either as leakage through pipes or incomplete combustion) contributes to GHG emissions. For the past several decades, methane extracted from the ground has been typically referred to as “natural gas” in many contexts. We find the term “fossil methane” more accurate and illuminating.

4 U.S. Energy Information Administration. (2021a, January 29). *Number of natural gas consumers* (Data series: No. of residential consumers). https://www.eia.gov/dnav/ng/ng_cons_num_a_EPG0_VN3_Count_a.htm

5 There are 5.5 million commercial customers and roughly 183,000 industrial customers. See U.S. Energy Information Administration. (2021b, January 29). *Number of natural gas consumers* (Data series: No. of industrial consumers). https://www.eia.gov/dnav/ng/ng_cons_num_a_EPG0_VN7_Count_a.htm. Gas LDCs serve some large industrial customers; other large industrial customers are served directly from transmission pipelines.

6 U.S. Energy Information Administration. (2020, December 3). *Natural gas explained: Natural gas pipelines*. <https://www.eia.gov/energyexplained/natural-gas/natural-gas-pipelines.php#:~:text=The%20U.S.%20natural%20gas%20pipeline,and%20storage%20facilities%20with%20consumers;> Méndez, A., King, C. W., Greer, D., & Gülen, G. (2019, January). *Local distribution companies: Relationship between pipeline miles and number of customers, and different pipeline diameter sizes*. University of Texas at Austin Energy Institute. https://energy.utexas.edu/sites/default/files/UTAustin_EIoF_Pipeline_Miles_and_Customers_2019-02-21.pdf; and Rocky Mountain Institute. (2019). *The impact of fossil fuels in buildings: A fact base*. <https://rmi.org/insight/the-impact-of-fossil-fuels-in-buildings/>

7 U.S. Department of Energy, Office of Energy Policy and Systems Analysis. (2017). *Natural gas infrastructure modernization programs at local distribution companies: Key issues and considerations*, p. 5. <https://www.energy.gov/sites/prod/files/2017/01/f34/Natural%20Gas%20Infrastructure%20Modernization%20Programs%20at%20Local%20Distribution%20Companies--Key%20Issues%20and%20Considerations.pdf>; Payne, H. (2021, January). *The natural gas paradox: Shutting down a system designed to operate forever*. SSRN. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3584378#

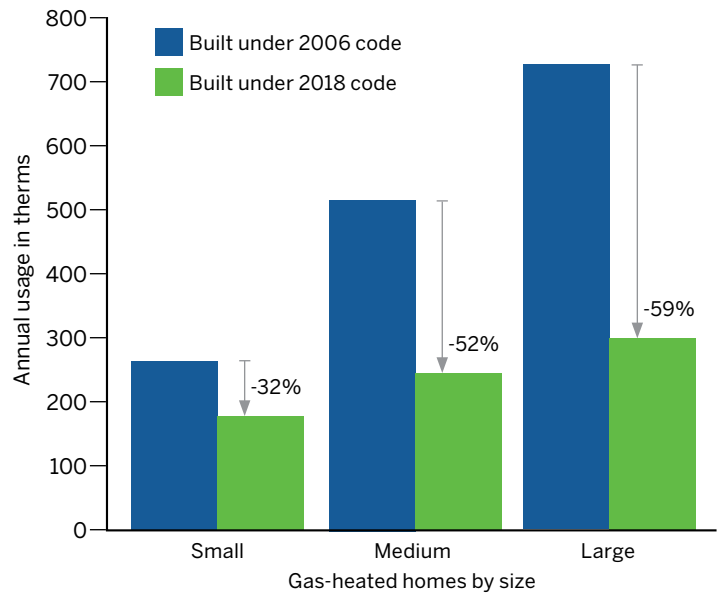
8 U.S. Energy Information Administration. (2020, November 30). *Natural gas explained: Use of natural gas*. <https://www.eia.gov/energyexplained/natural-gas/use-of-natural-gas.php>

Per-customer gas usage continues to decline.

Gas equipment, in part to compete with alternatives and in part because of public policy programs, has become increasingly efficient over time. In addition, building shells have become more efficient, particularly for new construction. As a result, while the number of residential and commercial customers went up nearly 47% from 1987 to 2019,⁹ gas consumption for these sectors increased only 26%.¹⁰ For example, a recent study of the impact of energy code changes in the state of Washington shows that new gas-heated homes use 32% to 59% less gas than those built to earlier codes (see Figure 3).¹¹

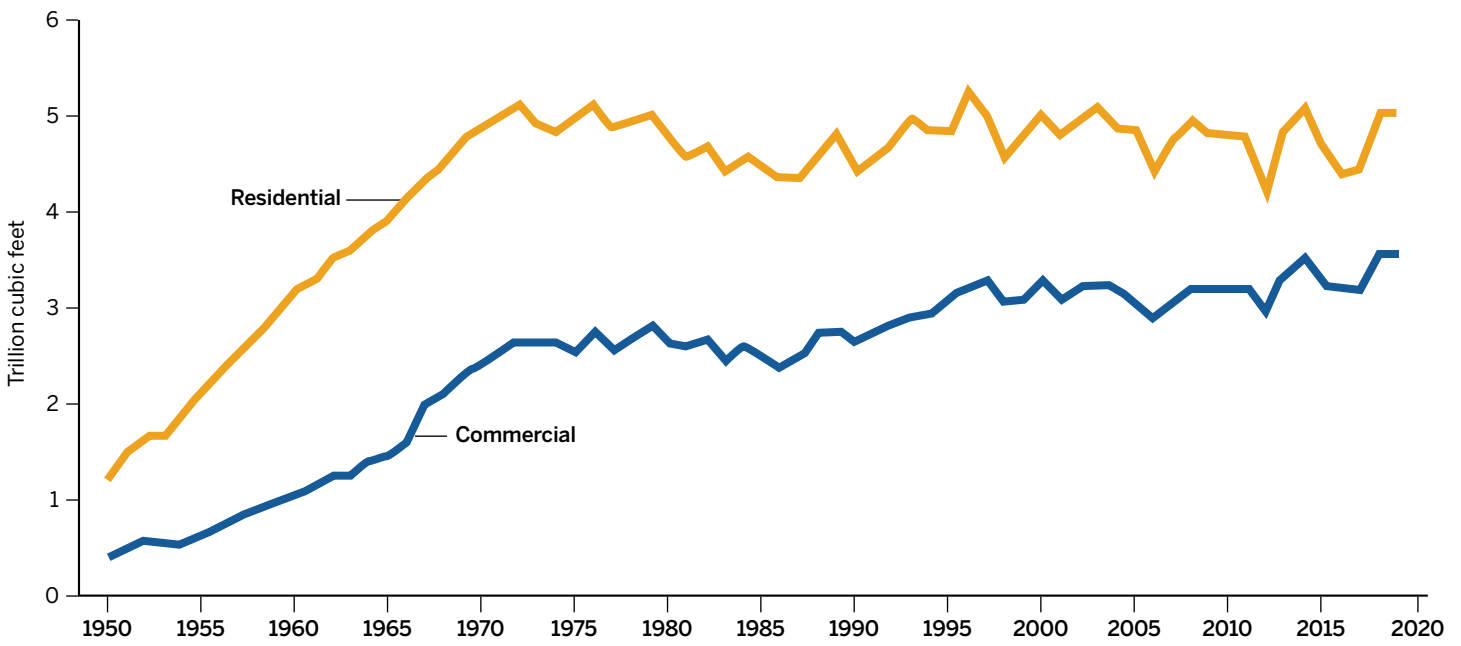
Figure 4 shows residential and commercial gas consumption.¹² Residential gas consumption was roughly flat from 1970 to 2019, while commercial gas consumption went up 46%.

Figure 3. Decline in home gas consumption under revised Washington state energy codes



Source: Based on Odum, H., Spielman, S., Banks, A., Kintner, P., Frankel, M., Reddy, D., & Peng, J. (2020, September). *Modeling the Washington State Energy Code: 2006 & 2018 Baseline Energy Consumption*

Figure 4. U.S. residential and commercial gas consumption



Source: U.S. Energy Information Administration. (2021, February 26). *Natural Gas: Natural Gas Consumption by End Use*

9 U.S. Energy Information Administration, 2021a.

10 U.S. Energy Information Administration. (2021c, February 26). *Natural gas: Natural gas consumption by end use*. https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm

11 Odum, H., Spielman, S., Banks, A., Kintner, P., Frankel, M., Reddy, D., &

Peng, J. (2020, September). *Modeling the Washington State Energy Code: 2006 & 2018 baseline energy consumption*, Appendix B. Washington State Department of Enterprise Services. https://sbcc.wa.gov/sites/default/files/2020-11/SBCC%20BaselineStudy%20Revised_inclusive%20Final_2020_Nov6.pdf

12 U.S. Energy Information Administration, 2021c.

Electric end-use equipment provides competitive alternatives to gas.

Electric end-use equipment that competes with gas equipment, such as heat pumps and induction cooktops, is declining in price, improving in quality and outpacing its gas-fueled counterparts in terms of efficiency and can provide important flexibility benefits to the electric grid.¹³ Heat pumps for space and water heating are capable of providing 1.5 to three times more heat energy than the heat value of the electrical energy they consume. Electric water heaters are flexible in that they can be charged and used at times other than when they are immediately needed, thus working like batteries to provide storage opportunities valuable for grid management. Induction stoves offer a more efficient and attractive alternative to gas for cooking than earlier, unpopular electric cooktop options.¹⁴

In certain segments, the technologies will require continued improvements to fully meet customer needs. Standard air-source heat pumps do not work as well in colder climates, but cold climate air-source heat pumps have been improving. Some customers in these regions may be able to install ground-source, or geothermal, heat pumps instead.¹⁵ Many industrial processes are not as amenable to electrification with current technology at current costs for the foreseeable future. Innovation will continue in all of these areas.

Greenhouse gas reduction targets are incompatible with status quo gas usage.

Many U.S. states have adopted targets and requirements for reductions in GHG emissions over time, aiming for

reductions over the next 25 to 30 years of at least 80% from individual baselines. Some more ambitious states have gone further, beginning to adopt net-zero GHG policies, and at the federal level, President Biden began his term by setting a national target of net-zero GHG emissions economywide by no later than 2050.¹⁶

The use of fossil gas causes GHG emissions during production, delivery and combustion, and the GHG emissions from fossil gas combustion are a substantial percentage of overall emissions. Combustion in the residential and commercial sectors constituted just over 9% of carbon dioxide emissions from energy in 2019.¹⁷ To meet longer-term GHG policies, these emissions must be reduced substantially or eliminated, and states with the greatest emissions from gas usage in buildings are among those that have committed to 80% decarbonization by 2050.¹⁸

Fossil gas has health, safety and environmental challenges.

In addition to GHG emissions, fossil gas causes other health, safety and environmental problems. Although hydraulic fracturing has allowed new gas deposits to be accessed, the downsides include significant water usage and wastewater management difficulties and increased seismic activity in areas where wastewater is reinjected into the ground.¹⁹ Methane leakage from production to delivery causes significant GHG emissions (see Figure 5 on the next page).²⁰ In the delivery system, these leaks pose a variety of potential problems, ranging from nuisances like killing trees²¹ to more serious

13 Shipley, J., Lazar, J., Farnsworth, D., & Kadoch, C. (2018). *Beneficial electrification of space heating*. Regulatory Assistance Project. <https://www.raponline.org/knowledge-center/beneficial-electrification-of-space-heating/>; and Farnsworth, D., Lazar, J., & Shipley, J. (2019). *Beneficial electrification of water heating*. Regulatory Assistance Project. <https://www.raponline.org/knowledge-center/beneficial-electrification-of-water-heating/>

14 See, for example, Northeast Energy Efficiency Partnerships. (n.d.). *Induction stoves: An option for new construction*. <https://neep.org/blog/induction-stoves-option-new-construction>

15 Shipley et al., 2018.

16 The White House. (2021, February 1). Tackling the climate crisis at home and abroad (Executive Order 14008). *Federal Register*, 86(19), 7619-7633. <https://www.govinfo.gov/content/pkg/FR-2021-02-01/pdf/2021-02177.pdf>

17 U.S. Energy Information Administration. (2021d, January 26). *Monthly energy review* (DOE/EIA 0035[2021/1]), tables 11.1 and 11.2. <https://www.eia.gov/totalenergy/data/monthly/previous.php>

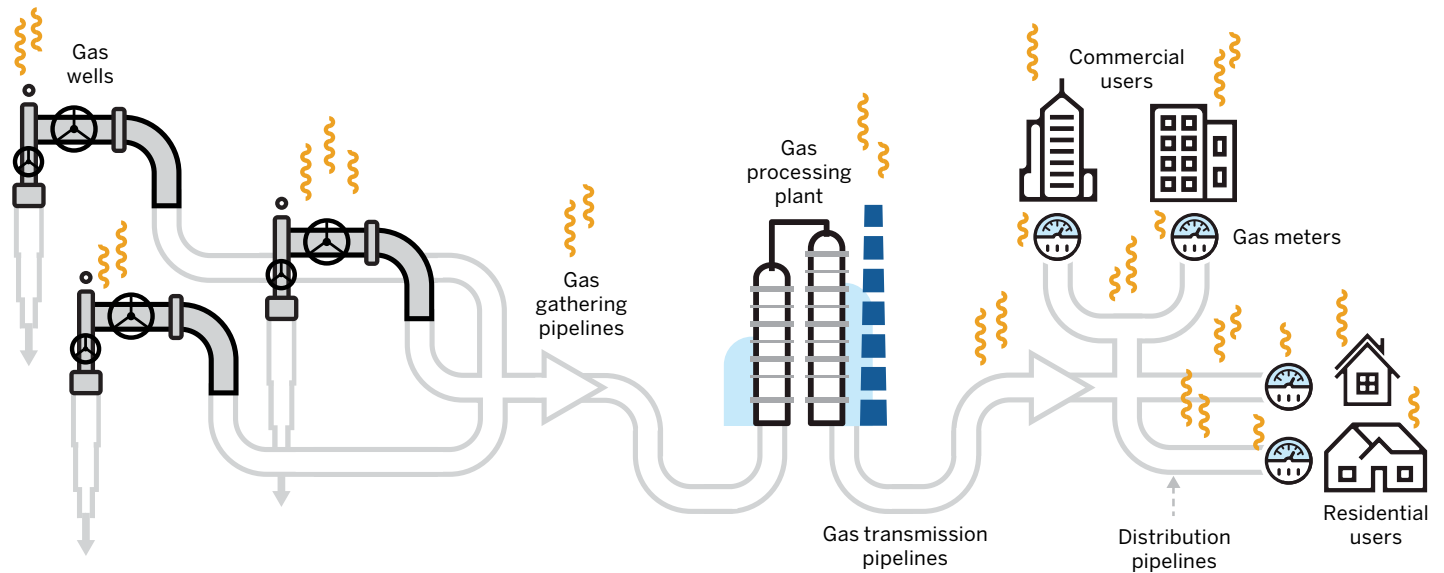
18 Ten states are responsible for 56% of building emissions nationally, and the top 10 states were responsible for 58% of direct building gas use in 2017. Rocky Mountain Institute, 2019.

19 Denchak, M. (2019, April 19). *Fracking 101*. Natural Resources Defense Council. <https://www.nrdc.org/stories/fracking-101>; U.S. Geological Survey. (n.d.). *What environmental issues are associated with hydraulic fracturing?* https://www.usgs.gov/faqs/what-environmental-issues-are-associated-hydraulic-fracturing?qt-news_science_products=0#qt-news_science_products

20 The Gas Index. (2020). *The United States' natural gas system has a serious problem: It leaks*. <https://thegasindex.org/>

21 Schollaert, C., Ackley, R. C., De Santis, A., Polka, E., & Scammell, M. K. (2020, August). Natural gas leaks and tree death: A first-look case-control study of urban trees in Chelsea, MA USA. *Environmental Pollution*, 263(Part A). <https://www.sciencedirect.com/science/article/pii/S0269749119376717?via%3Dihub>

Figure 5. Stages of the gas supply chain responsible for methane leakage



Note: Methane is colorless, but for purposes of illustration, leakage is represented in yellow.

Source: The Gas Index. (2020). *The United States' Natural Gas System Has a Serious Problem: It Leaks*

hazards to human health and safety.²² Finally, even the proper operation of gas equipment within homes, such as gas stoves, can degrade indoor air quality and impact health.²³

Alternative gases have major cost and availability challenges.

Alternative gases, such as green hydrogen and biogases (see the next page), may become a key part of a decarbonized economy for hard-to-electrify sectors such as aviation, shipping and heavy industry.²⁴ These alternatives are not, however, likely to replace the use of fossil gas, in particular in residential and commercial settings, for several reasons:²⁵

- It would take five times more wind or solar energy to create the hydrogen needed to heat a home than it would to heat the same home with a heat pump.
- Hydrogen's different chemical properties mean that it cannot be transported in the same pipelines as fossil gas except as a blend of gas containing a small percentage of hydrogen. Hydrogen alone can corrode older pipes and can leak more in newer pipes. It is highly flammable but currently undetectable when leaking. Moreover, meters, appliances or at least burner tips would need to be replaced to support hydrogen usage.
- Although green hydrogen is falling in price due to increased investment, it is currently relatively expensive. Demand for green hydrogen for residential and commercial uses could lead to decreased supply for hard-to-electrify uses where it is needed most.
- Investing heavily in hydrogen infrastructure and using blue hydrogen (which is extracted from fossil gas) until

22 Branham, D. (2018, February 27). What causes gas explosions? What can homeowners do to avoid them? *The Dallas Morning News*. <https://www.dallasnews.com/news/2018/02/27/what-causes-gas-explosions-what-can-homeowners-do-to-avoid-them/>

23 Seals, B., & Krasner, A. (2020). *Health effects from gas stove pollution*. Rocky Mountain Institute, Physicians for Social Responsibility, Mothers Out Front, & Sierra Club. <https://rmi.org/insight/gas-stoves-pollution-health>; and Seals, B. (2020, May 5). *Indoor air pollution: The link between climate and health*. Rocky Mountain Institute. <https://rmi.org/indoor-air-pollution-the-link-between-climate-and-health>

24 Fakhry, R., & Harding, R. (2020, August 6). "Green" hydrogen: Critical to powering a carbon-free future. Natural Resources Defense Council. <https://www.nrdc.org/experts/rachel-fakhry/green-hydrogen-critical-powering-carbon-free-future>

25 Rosenow, J. (2020, September 30). *Heating homes with hydrogen: Are we being sold a pup?* Regulatory Assistance Project. <https://www.raponline.org/blog/heating-homes-with-hydrogen-are-we-being-sold-a-pup/>

Types of alternative gases

Hydrogen is one alternative for limited end uses. Whether hydrogen provides a substantial decrease in GHG emissions and other pollution depends on how it is produced.²⁶

- **Brown and black hydrogen:** produced by transforming coal into gas at very high temperatures. Brown hydrogen comes from brown coal, or lignite; black coal comes from bituminous or hard coal. Black and brown hydrogen production creates carbon monoxide and carbon dioxide pollution.
- **Gray hydrogen:** extracted from fossil gas using thermal processes, such as steam methane reformation, which uses water to separate the hydrogen from the fossil gas carbon molecules. Most hydrogen produced today is gray hydrogen. Because steam methane reformation generates and releases excess carbon dioxide — about 9.3 kilograms per kilogram of hydrogen — gray hydrogen does not offer climate benefits.
- **Blue hydrogen:** extracted from fossil gas using thermal processes but with the carbon dioxide emissions captured and stored in industrial carbon capture and storage processes. Blue hydrogen has fewer carbon emissions than gray hydrogen, but 10% to 20% of the carbon emissions cannot be captured. Production of the fossil

gas from which the hydrogen is extracted also causes carbon emissions.

- **Green hydrogen:** produced through electrolysis, which splits water molecules into oxygen and hydrogen, using electricity generated by zero-emissions sources.

Biogases are also possible alternatives to the use of fossil gas, but constraints, including limited feedstocks for production, make widespread use infeasible.²⁷

- **Biogas:** produced from the anaerobic digestion of organic matter, which results in a mixture of methane, carbon dioxide and small amounts of oxygen. The precise composition of biogas depends on the feedstock and method of production, which include biodigesters, landfill gas recovery systems and wastewater treatment plants.²⁸
- **Biomethane:** a near-pure methane, sometimes known as renewable natural gas, created either by removing the carbon dioxide and other contaminants in biogas or through the gasification of solid biomass, which results in a mixture of gases (sometimes called syngas), followed by methanation, which causes a reaction between the component gases to produce methane.²⁹

green hydrogen decreases in price would only exacerbate the problems already facing the gas industry. Hydrogen infrastructure may very well also become a stranded asset if electric options are adopted based on current affordability and efficiency.

- Biogas and biomethane as alternatives face challenges because neither can be efficiently produced at the scale needed to replace current fossil gas usage.

Pairing growing investments with significant declines in gas throughput could drive up rates.

Gas systems require continuing maintenance and repair and sometimes pipe replacements, as well as investment in expansion if new customers are added to the system. Over the past decade, a number of jurisdictions have adopted special investment programs to address safety issues, reliability concerns and methane leakage.³⁰ Many of these programs

26 Giovannini, S. (2020, November 13). *50 shades of (grey and blue and green) hydrogen*. Energy Cities. <https://energy-cities.eu/50-shades-of-grey-and-blue-and-green-hydrogen/>

27 Nevzorova, T., & Kutcherov, V. (2019, November). Barriers to the wider implementation of biogas as a source of energy: A state-of-the-art review. *Energy Strategy Reviews*, 26. <https://www.sciencedirect.com/science/article/pii/S2211467X19301075>

28 International Energy Agency. (2020). *Outlook for biogas and biomethane:*

Prospects for organic growth. <https://www.iea.org/reports/outlook-for-biogas-and-biomethane-prospects-for-organic-growth/an-introduction-to-biogas-and-biomethane>

29 International Energy Agency, 2020.

30 Thanos, A., & Zitelman, K. (2020, January). *Natural gas distribution infrastructure replacement and modernization: A review of state programs*. National Association of Regulatory Utility Commissioners. <https://pubs.naruc.org/pub/45E90C1E-155D-0A36-31FE-A68E6BF430EE>

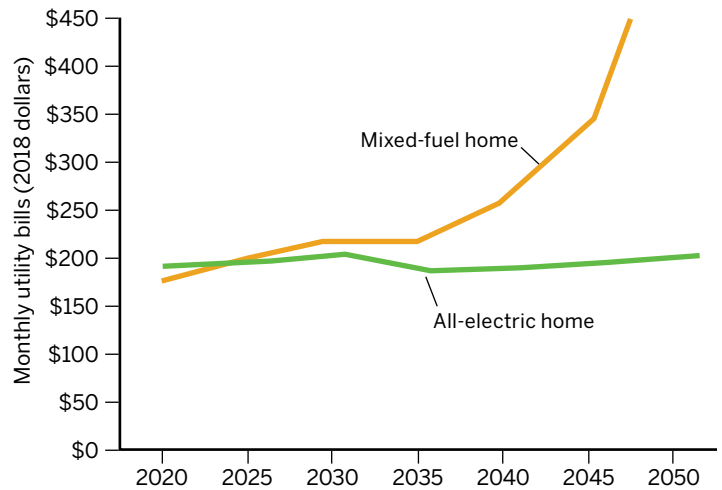
come with streamlined investment approvals and dedicated cost recovery mechanisms. This continuing investment in the system, while both the overall customer base and gas throughput are either flat or decreasing, will almost certainly drive up rates and bills.

While reliability for existing customers and safety should not be compromised, regulators need to scrutinize justifications for significant new long-lived investments. In some cases, repairs will solve the issue in a reasonable manner at a lower overall cost, which would either be expensed or involve lower levels of investment that could be paid off quickly. In other cases, some portions of the existing gas system could be retired responsibly, with support for remaining gas customers on that segment to affordably convert to modern and clean energy options.

The consulting firm Energy and Environmental Economics analyzed the effects on gas rates as demand for gas declines in several different scenarios for California, assuming shareholders are not asked to bear any additional burden of stranded assets and no alternative source of funding is found. In short, rates for residential gas customers are projected to increase dramatically with increased electrification and attendant decreases in gas demand, as shown in Figure 6.³¹

These potential impacts on rates would affect all gas customers, but the relative impacts to LMI customers would likely be much greater. Energy bills are a higher percentage of

Figure 6. Projected increase in gas consumers' bills under high electrification



Source: Aas, D., Mahone, A., Subin, Z., MacKinnon, M., Lane, B., & Price, S. (2020). *The Challenge of Retail Gas in California's Low-Carbon Future: Technology Options, Customer Costs, and Public Health Benefits of Reducing Natural Gas Use*

income for LMI customers, and under current policies, fewer LMI customers are likely to be early adopters of modern and clean alternatives to gas. At the same time, this magnitude of rate increases would likely trigger customers who can to switch away from gas equipment or exit the gas system entirely.

Gas system operations and regulation have developed and adapted over time. In the next sections of this paper, we outline recommendations that might facilitate the next changes in gas system evolution.

31 Aas et al., 2020.

Alternative ways to share cost burden beyond current and future gas customers

Policymakers may look to other sources of funding to ameliorate rate impacts on future gas customers. There is no silver bullet, as many sources come with significant complications. The following options for consideration could provide valuable longer-term certainty for regulated companies, their employees and other stakeholders.

- **General funds and taxes** could provide funding to assist with the gas transition. Direct funding from the state or federal government, as well as various forms of tax assistance, could be significant, although budgets are often constrained. Other possibilities could include incentives for electric companies to absorb gas utilities in their service areas or incentives for combination holding companies to merge electric and gas operations.
- **Securitization**, or refinancing remaining capital payments for certain assets with low-cost debt, can lower overall costs of capital and provide consumer savings. Refinancing does not eliminate these costs but can lower the interest rate below even the typical utility cost of debt by providing additional guarantees from ratepayers or even an ultimate backstop from the government. The utility and regulators may pass these savings directly to ratepayers or could apply the savings from refinancing to meet transition goals. This debt can still impact the books of the utility in question or, in limited circumstances, the government providing the final backstop, potentially impacting bond ratings.
- Utilities could impose **exit fees** for customers leaving the system, thus creating a source of revenue to assist remaining customers with increased costs. Exit fees are typically considered to be anti-competitive and may be contrary to the expectations of many customers. Such a policy would have the side effect of discouraging full electrification or adoption of other low- or zero-GHG technologies.
- Regulators could allocate certain program costs, as well as an increased share of administrative and general expenses for joint gas and electric utilities, to **electric customers**. This option raises questions about how core gas system costs are treated and whether such an allocation of such costs to electric customers is equitable.
- Regulators could authorize gas utilities to **change the scope of their services** by investing in other low- or zero-GHG technologies, such as district energy systems. By expanding their reach, gas utilities could gain additional customers at a time when the utility is otherwise shrinking, though such an expansion would not come without complexities. While this option may lower the burdens of existing gas customers, it is not clear that putting those costs on customers adopting new, clean technologies is justified, although there could be synergies with administrative and general costs.
- Often **gas utility shareholders** bear at least some of the costs for stranded assets that are no longer used and useful or otherwise do not provide meaningful value to the system. This type of risk has been reflected in the return on equity and market valuations over time, which can make it reasonable for shareholders to share in any burden.



III. Revitalize Gas Utility Planning

As noted earlier in this paper, climate policy, clean energy goals and an improving economic case for electrification are causing a transition away from fossil gas regardless of whether regulators, decision-makers and stakeholders are ready for this shift. Whether the transition is a graceful one depends on how regulators and others plan for and anticipate the coming challenges and opportunities. First among the tools available to regulators is the ability to require gas utilities to develop plans that anticipate these changes. This section outlines steps that regulators can take to revitalize and refresh gas planning requirements, with an eye toward creating a gas transition planning process that will allow regulators to plan for a future with fewer end uses served by fossil gas. A robust and data-driven planning process, informed by stakeholder input, will provide a guide for regulators and utilities alike as they navigate a changing landscape for gas utilities.

Following the trend in the 1970s and 1980s for electric utilities, the Energy Policy Act of 1992 instructed states to consider the adoption of integrated resource planning (IRP) for gas utilities, along with other measures to enhance energy efficiency programs and incentives.³² IRP for any type of utility is intended to rationalize and systematize many pieces of the planning process, including fair consideration of least-cost demand-side resources. Many states did not adopt these discretionary standards, but others do require some sort of IRP for gas utilities.³³ In some places, the requirements are similar to what may be included in the electric utility IRP process,

including stakeholder processes, information regarding the current system and customers, alternative scenario development and short- and long-term action plans.³⁴ In other states, less comprehensive analysis is required, or the outlines of the planning process have been developed through regulatory commission order or some combination of requirements.³⁵

Changing circumstances justify a fresh look at gas planning requirements to ensure that utilities are providing enough information for regulators, utilities and stakeholders to determine whether utility decision-making is prudent for customers and in line with state policy goals. Some states may need legislation or amendment to existing rules to allow regulators to obtain information for sufficient planning efforts.

The issues and trends discussed in Section II will have several consequences that will make information gathering and planning requirements more important moving forward: (1) the overall demand for fossil gas is likely to decrease; (2) the number of connected gas utility customers will decrease as a result of increasing electrification; and (3) as a result, the throughput on the gas distribution system will diminish. By requiring utilities to develop gas transition plans, regulators can ensure that regulators, utilities and stakeholders have the information they need to develop pathways that take into account policy goals, changing demand and potential impacts to customers.

Regulators can first revisit their gas planning requirements to determine whether the utility is providing sufficient

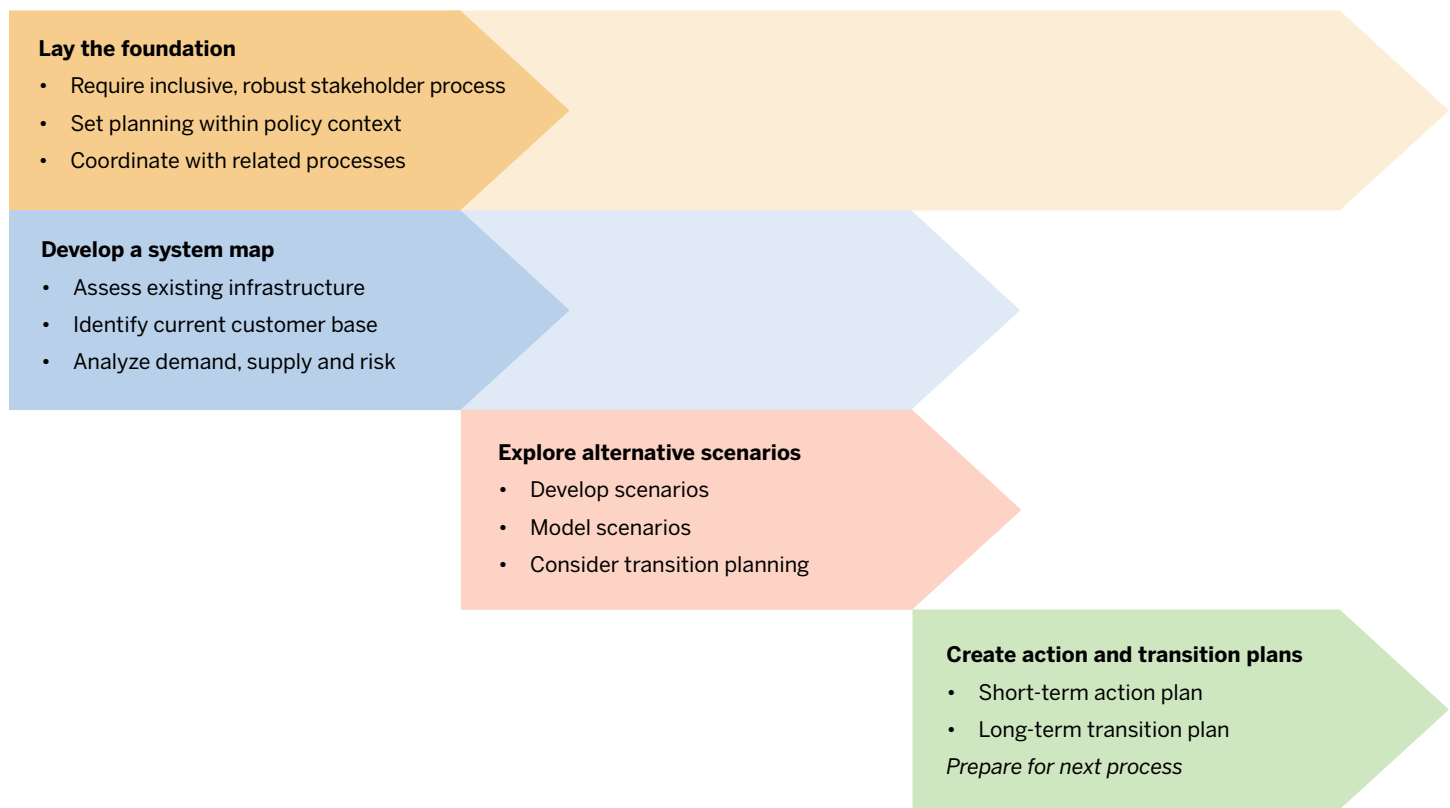
32 See 15 U.S.C. § 3203. Shortly afterward came the publication of two reports on the subject: Goldman, C. A., Comnes, G. A., Busch, J. F., & Wiel, S. (1993). *Primer on gas integrated resource planning* (Report No. LBNL-34144). Lawrence Berkeley National Laboratory. <https://emp.lbl.gov/publications/primer-gas-integrated-resource>; and Harunuzzaman, M., & Islam, M. (1994). *Integrated resource planning for local gas distribution companies: A critical review of regulatory policy issues* (Report No. NRRI 94-12). National Regulatory Research Institute. <https://pubs.naruc.org/pub/74F6F9EE-155D-0A36-31B0-9D798D1DD8CF>

33 Harunuzzaman & Islam, 1994. See, for example, NM Administrative Code 17.7.4; OR Administrative Rules 860-027-0400, Integrated Resource Plan Filing, Review, and Update; and RI General Laws § 39-24-2.

34 NM Administrative Code 17.7.4; RI General Laws § 39-24-2.

35 For example, in Idaho, IRP requirements are set in commission orders No. 25342, 27024, 27098, 32855, 33314 and 33997. In Oregon, administrative rule and commission orders set the IRP requirements: OR Administrative Rules 860-027-0400, commission orders No. 07-002, 07-047 and 08-339.

Figure 7. Gas planning process



information about its gas system and add requirements if more data is needed to fully assess the gas utility's role in meeting end uses. Regulators may then want to require a gas utility to develop a gas transition plan, in which the utility outlines how its system and operations will change as gas ceases to be the predominant fuel for many end uses.

Figure 7 provides an overview of the entire gas planning process. The elements in this figure will be discussed in more detail below.

A. Lay the Foundation With Engagement, Context and Coordination

We recommend first that regulators ensure that their planning processes are grounded in a solid foundation of stakeholder input, relevant policies and goals and, to the extent possible, coordination with related planning processes. By establishing this shared context, regulators, utilities and stakeholders can move to planning for future needs with a common

understanding of potential challenges and opportunities. This information equips regulators with the information they need to address changes in the gas system, driven by the trends noted above.

Require an Open, Inclusive and Robust Stakeholder Process

Regulators can first ensure that planning requirements include an open, inclusive and robust stakeholder process. Stakeholder input is critical at the beginning of a gas planning process to ensure that regulators and the utility are not only hearing the perspective and ideas of the utility itself but are also hearing new input and points of view that add to the planning process, especially as technology and customers are evolving. In areas where gas planning has been limited, or where it has not been open to the public, greater emphasis and attention to developing the stakeholder process may be warranted.

Stakeholder processes are generally familiar to utilities, regulators or other traditional stakeholders. Regulators can

pull from electric IRP or other proceedings to design effective public advisory processes. Regulators may want to seek input from utilities and stakeholders about best practices to guide these processes. We recommend the following as critical elements for an effective stakeholder proceeding:

- The stakeholder process should begin at least one year prior to the filing date of the gas transition plan to ensure input into the development of the plan. Utilities should provide information about the process; time, date and location of the first meeting; an opportunity for stakeholders to notify the utility of their interest in the proceeding; and utility contact information.
- Because utility gas planning may be new to many states, the utility should be required to reach out to parties that normally intervene in other utility proceedings, including IRP processes on the electricity side.
- Meetings held as part of the process should be open to the public, noticed and scheduled on a regular basis, and set at times that allow for the maximum participation possible, with particular attention paid to the needs of stakeholders representing low- to moderate-income customers and underserved communities, who are often left out of or marginalized in such processes.
- Meetings should be facilitated by a neutral third party or by commission staff. Meeting notes should be kept and be made available online, along with attendance logs and any relevant meeting materials. Meetings should offer virtual participation for those stakeholders unable to attend in person.
- The utility should provide relevant and timely background information about its current system, including system maps, needs and upcoming demands or constraints, in advance of the first meeting. This information should track the information to be provided in the utility's gas plan; for subsequent planning processes, a copy of the previous gas plan, along with a nontechnical summary of the plan, may be sufficient.
- The utility should provide advance information about what will be discussed in each meeting, including background information and contact information for utility employees or consultants to whom stakeholders may direct questions or seek clarification before or after each meeting.
- The purpose of the stakeholder process will be to inform the gas plan before both its development and its filing. All feedback from stakeholders should be documented and reflected clearly throughout the process — noting areas of consensus and nonconsensus and noting which changes have been adopted or not. This documentation will help inform regulators of the process and the outstanding items they will need to consider as part of their decision-making about the filed plan.
- The utility will provide an explanation when it requests to keep information confidential or requires participants to sign nondisclosure agreements before viewing potentially confidential information. Regulators can provide a means by which stakeholders can contest the utility's confidentiality assertions to the regulators.
- The utility will design meetings around the topics and subject areas required in the gas plan, such as demand forecasts; existing and future supply; demand-side resources; modeling and risk assumptions; the cost and general attributes of potential new resources; assumptions, data and methods used to develop scenarios; scenario analyses; and rate design options, including how the plan may impact different classes of customers, particularly LMI customers.
- Consider having the utility provide funding³⁶ for participation of independent technical experts, vetted and approved by regulators, who can assist stakeholders to understand utility proposals and develop responses and input.
- Consider having the utility provide financial assistance for participation of stakeholders who can demonstrate need.

36 Regulators may determine that utility shareholders bear these costs, or they may allow some of this funding to flow from rates. Alternatively, where legislators have allocated funding for stakeholder participation in public

utility commission proceedings, funding may come from the commission itself or contributions that the commission and the utility make to a stakeholder fund.

Set Planning Within the Context of Relevant Policies and Goals

In addition to the opportunity for the stakeholder process to inform the context in which gas planning is occurring, regulators should further define the boundaries of the process by requiring an analysis of any policy goals that may constrain utility action or that may provide incentives for a utility to move toward an end goal in the short or long term. One prevalent example will be any carbon reduction targets that limit the amount of fossil fuels used in the state and that may set specific limitations on gas utilities. Other policies — such as requirements for minimization of system costs or for new construction to be all electric, or indoor air quality standards that limit gas appliances³⁷ — will affect gas demand projections and gas network expansion.³⁸ The gas plan should spell out these policies, including any expected changes, to ensure that they are woven into the planning process.

Coordinate Gas Planning With Related Planning Processes

As the trends affecting the gas industry are not limited to gas utility proceedings, regulators may want to consider coordinating or at least cross-referencing other planning processes that may affect gas utility decision-making. Consideration of electric utility plans, for example, may be important to determine whether gas and electric utilities are making similar assumptions about electrification and anticipating that as electrification proceeds, demand for gas will decrease and demand for electricity will increase. Both outcomes will need to be addressed and information about challenges and opportunities of those transitions shared.³⁹ Furthermore, as gas is phased out, plans to transition to electric alternatives are needed. The transition must be smooth

enough that customers are not caught in between systems. Regulators may want to consider other state agency planning processes that will affect demand for gas. Air quality agencies, for example, may be developing appliance standards that will affect gas demand. By having direct communication or coordination with other agencies with jurisdiction over gas utilization, utility regulators will improve their own planning processes.

There are numerous ways and degrees to which regulators could arrive at a more holistic view of the energy system through coordinated planning:

- Regulators could require combined gas and electric utilities to merge data from both the gas and electric systems to develop one integrated plan, an energy plan.
- Regulators could mandate that separate gas and electric utilities coordinate planning to arrive at one planning document. This outcome could be achieved through the use of an umbrella council that would develop the energy plan, informed by the gas and electric utilities.
- Regulators could instruct separate gas and electric utilities to coordinate a joint filing or to file plans on a parallel timeline that cross-referenced information from the coupled plan.
- Regulators could include a requirement in the planning process for utilities to reach out to agencies with related planning processes during the stakeholder process, to present during planning meetings to stakeholders and the commission, or to submit comments to the gas utility planning process that address overlap or concerns.

Coordinated planning may be done among regulatory bodies, agencies, utilities and stakeholders. Legislation could require such coordination, or regulatory or energy agencies could take the lead to develop a coordinated body with

37 See, for example, California Air Resources Board. (2020, November 19). *California Indoor Air Quality Program update* (Resolution 20-32). <https://ww3.arb.ca.gov/board/res/2020/res20-32.pdf>

38 Other states may be proposing more rigorous changes. Legislators in Washington, for example, have introduced a bill that would implement a new clean heat standard that would limit “the expansion of the natural gas system for residential and commercial space and water heating, and advancing the use of high-efficiency electric equipment, production and distribution of clean fuels, and the safe and equitable transition of the natural gas system.” It also addresses a gas company’s obligations regarding

service and shifts line extension costs to a new customer requesting service. Washington Legislature, HB 1084, 67th Legislature, 2021 Regular Session. <http://lawfilesexternal.wa.gov/biennium/2021-22/Pdf/Bills/House%20Bills/1084.pdf?q=20210126020523>

39 For example, an electric utility may have information about the relative cost to serve different customer load segments where the gas utility may be considering decreases in service. Having information about the ultimate costs of this transition, not just costs on the gas or electric side of the equation, may reveal opportunities for cost savings for customers or uncover challenges in meeting increased electric demand.

oversight over planning. An integrated planning body could come together to align goals⁴⁰ that may be set by regulators, municipalities and the state, ensuring that planning is occurring in a manner that moves toward action to meet those goals. An integrated planning body could provide a platform to facilitate data sharing and to ensure that planning efforts are transparent.

In any of these scenarios, regulators should watch out for efforts or plans that appear to be coordinated but that are ultimately parallel planning processes with some mention of the other.⁴¹ Awareness of other stakeholders' work does not automatically equal a coordinated effort.

B. Develop a System Map

With the context underlying the utility's planning firmly set, regulators can next examine the elements of the gas planning process itself to ensure that the process is leading to robust and data-driven outcomes. We recommend that regulators start by requiring utilities to build a system map made up of layers of information about the system, including infrastructure, customer base, demand and supply and the assumptions upon which the utility is operating.⁴² The system map would provide a map of on-the-ground information about the physical system, as well as layers of more dynamic information about the system that may be on the map itself or explained in supplementary information.

This information can inform several basic steps of system planning: first, the development of alternative plans to meet current and projected demand; second, analysis of

these scenarios to test them against considerations of cost, risk, equity and consistency with future planning; and third, future or transition planning that anticipates how immediate planning decisions sit within the context of a changing system. Regulators may want to think of these steps as more iterative than strictly sequential, as different alternatives are tested and stakeholders and others provide continuing input.

Utilities maintain a wealth of information about their operations that they can compile into layers in a system map. We recommend that regulators require utilities to perform the following evaluations. The outputs will serve as a foundation for a system map that provides regulators and stakeholders with a touchpoint for planning discussions.

Assess Existing Infrastructure

The basis of the system map will be the utility's service territory and existing infrastructure, including:

- Transmission, distribution and gas service infrastructure, including the length and diameter of pipelines, pipeline material and pipeline pressure. This description should include the condition of existing pipelines, including the age and condition of the pipes, the presence of Aldyl-A pipe,⁴³ leakage rates (number of leaks per mile) and depreciation status.
- Interconnects, gate stations, compressor stations and any storage facilities.
- Areas of constraint on or congestion in the system.
- Areas where maintenance or replacement of existing infrastructure may be needed and an explanation for why

40 See, for example, Valova, R., Hart, C., Bourgeois, R., & O'Brien-Applegate, J. (2020, July). *Zero net gas: A framework for managing gas demand reduction as a pathway to decarbonizing the buildings sector*. Pace Energy and Climate Center. <https://peccpubs.pace.edu/viewresource/fba9aef7758065f/Zero+Net+Gas%3A+A+Framework+for+Managing+Gas+Demand+Reduction+as+a+Pathway+to+Decarbonizing+the+Buildings+Sector;Gridworks>. (2021). *Gas resource and infrastructure planning for California: A proposed approach to long-term gas planning*. https://gridworks.org/wp-content/uploads/2021/01/CA_Gas_Resource_Infrastructure_Plan_Report_FINAL.pdf; and New York Public Service Commission, Case No. 20-G-0131, Proceeding on motion of the commission in regard to gas planning procedures, Order instituting proceeding, March 19, 2020. <http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=20-G-0131&CaseSearch=Search>

41 Puget Sound Energy provides an example, with its integrated resource plan, of a utility that serves electric and gas customers combining its planning processes into one document. The plan does not take the next step of coordinating these processes, however, to consider, for example, how

electrification might decrease gas demand at the same time it increases electric demand. Puget Sound Energy. (2017). *2017 PSE integrated resource plan*. <https://pse-irp.participate.online/past-IRPs/2017>

42 See, for example, NM Administrative Code 17.7.4.10(e), Contents of the Gas IRP (requiring "a summary description of natural gas supply sources and delivery systems"); and Gridworks, 2021, Appendix 1.

43 Numerous federal safety advisories dating to 1998 have been issued for Aldyl-A plastic pipe, which was manufactured by DuPont before 1973, because of its history of cracking, resulting in explosions that have caused numerous fatalities. See Van Derbeken, J. (2011, September 26). Plastic natural gas pipe failure data kept secret. *San Francisco Chronicle*. <https://www.sfgate.com/news/article/Plastic-natural-gas-pipe-failure-data-kept-secret-2308629.php>. See also U.S. Pipeline and Hazardous Material Safety Administration. (2007, September 6). Pipeline safety: Updated notification of the susceptibility to premature brittle-like cracking of older plastic pipe. Docket No. PHMSA-2004019856. *Federal Register*, 72(172), 51301-51303. <https://www.govinfo.gov/content/pkg/FR-2007-09-06/pdf/07-4309.pdf>

these areas need attention, such as safety considerations or aging or damaged pipes.

Identify Current Customer Base

The next layer will describe the utility's existing gas system customer base. This information can be illustrated on the system map so that the map reveals the relationship between existing infrastructure and customer classes. The narrative section can include more detail about the makeup of the different classes. Minimum components include:

- The size of all customer classes, including residential, commercial, industrial and transportation customers.
- Firm versus interruptible customers.
- Density of service areas (number of customers and demand).
- Areas that the utility has considered for system expansion or contraction.
- Areas that the utility has identified as difficult to serve.
- Any additional detail about its customer base that might affect planning.

Analyze Demand

The next layer is an assessment of the utility's current and anticipated demand and its assumptions to reach those projections. This data is most useful when broken down by customer class, by season and by volumetric and peak requirements, based on current and historical delivery. Regulators might want the utility to include factors that it considers when assessing demand. These could include weather forecasting assumptions, current efficiency or demand-side management requirements or programs, and an analysis of the potential for electrification of gas end uses that may occur naturally, because of cost-effectiveness over the planning horizon, or with the assistance of programs that address inherent market barriers.⁴⁴

Once the utility has outlined current demand assessment practices and data, it can then outline factors it uses currently to forecast changes to demand. This analysis may include considerations of any areas where the utility is seeing changes in gas usage due to electrification, potential programs that might incentivize electrification or remove market barriers, or areas of increased gas usage. Requiring data on changes in customer base and differences in gas throughput will provide regulators a fuller picture of how gas demand may be changing.

Analyze Supply and Risk

The next layer consists of an assessment of the sources of supply that the utility uses to meet current and anticipated demand and how the utility hedges against changes in load and contingencies in the stability of its supply.

The utility can first outline current supply. This description may include sources of supply, supply contracts, including amounts and duration of the contracts, and any storage or contingency supply resources. Regulators can require the assessment to include any known or anticipated concerns about current sources of supply, such as anticipated price increases, previous delivery problems including any constraints due to weather or transmission limitations, potential changes in sources of supply and attendant considerations about possible needs for gas connection moratoria.⁴⁵ To the extent sources of supply can be represented on the system map itself, regulators might require the utility to do so.

Once the utility has laid out its sources of supply, it can conduct a risk analysis of these sources. The utility can outline both the risk of not maintaining supply reserves and redundancies and the cost of maintaining those reserves. The analysis can include a discussion of risks to the system from supply and delivery constraints, noting in particular how critical facilities may be affected. This analysis will be useful to later considerations of alternatives.

44 Consolidated Edison Company (ConEd) of New York, for example, is developing a Smart Solutions Program to reduce demand as a result of uncertainties around supply. With this program, ConEd is focusing on demand-side management, including non-pipeline alternatives, an enhanced energy efficiency program, a gas demand response program and a gas innovation program. Consolidated Edison Company of New York. (2019). *Gas long-range plan: 2019-2038*, pp. 23-24. <https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/gas-long-range-plan.pdf>

45 New York's Consolidated Edison, for example, bases its planning "on the assumption that temporary moratoriums will be necessary in our service territory and will remain until more pipeline capacity becomes available or reduced demand is realized through non-traditional supply, demand side solutions and the use of alternative new technologies to meet customer needs." Consolidated Edison Company of New York, 2019, p. 6.

Regulators might require the utility to outline its current practices to address known or anticipated changes in supply. This discussion may include how the utility forecasts costs to meet continued or new demand and whether meeting demand will require investment in additional infrastructure to access new sources of supply. The plan can describe the utility's procurement practices for acquiring new or additional supply, including any limitations in competitive procurement.

By requiring a baseline system mapping exercise, regulators ensure that they have the information they need about the state of the utility's system, the customer base, current demand and supply, and demand and supply trends. This information will provide regulators, stakeholders and the utility itself with the baseline needed to then consider future planning.

C. Explore Alternative Scenarios

Once the gas utility has mapped its system and customer base, we recommend that regulators require the utility to develop alternative scenarios about what may be needed for the system in future years, to analyze those scenarios against defined metrics, and to consider scenarios that anticipate planning for a transitioning gas system.

Develop Scenarios

The alternatives section often constitutes the heart of a planning process because it provides the opportunity to compare the pros and cons of various options, including the status quo. In addition, the process of developing alternatives allows the utility, stakeholders and regulators to contribute to thinking about different ways that the utility might meet demand in a cost-effective and efficient manner. As a result, this section of the plan ensures that the status quo does not win the day merely because it has the tide of inertia behind it.

Regulators can require that utilities consider a wide range of alternatives that take into account changing circumstances and assumptions. We present some minimum considerations for alternative development here, but the development of scenarios need not be limited to strict guidelines. Rather, it is

an opportunity for regulators, utilities and stakeholders to put ideas on the table for discussion.

Elements that regulators may want to require in different scenarios include:

Varying demand levels: At a minimum, the utility may be required to forecast low, mid and high demand. The utility can outline the factors that would drive those scenarios and use that information to develop the levels of demand to model. Several factors may inform these scenarios: state decarbonization goals and whether those can be met with gas usage at current or even decreased levels; the likelihood of customers leaving the gas system or reducing demand as a result of increases in electrification; increased building efficiencies leading to decreases in demand for gas; and the utility's own energy efficiency programs. An analysis of increased electrification of current sources of gas demand may be informed by reference to electric utility forecasts of fuel switching and consequent increased electricity demand. Certain state or local regulations, such as appliance efficiency standards, indoor air quality rules or all-electric building codes, may further inform demand forecasts.

Varying supply levels: Regulators may want utilities to consider scenarios in which uncertain sources of gas supply are no longer available or contract terms cannot be renegotiated. Regulators can then ask the utility to build on these elements by considering how varying demand and supply levels affect how the gas system is used in the future. Here, we recommend that regulators require utilities to use the system map described above to investigate and illustrate data relevant to developing alternative scenarios.

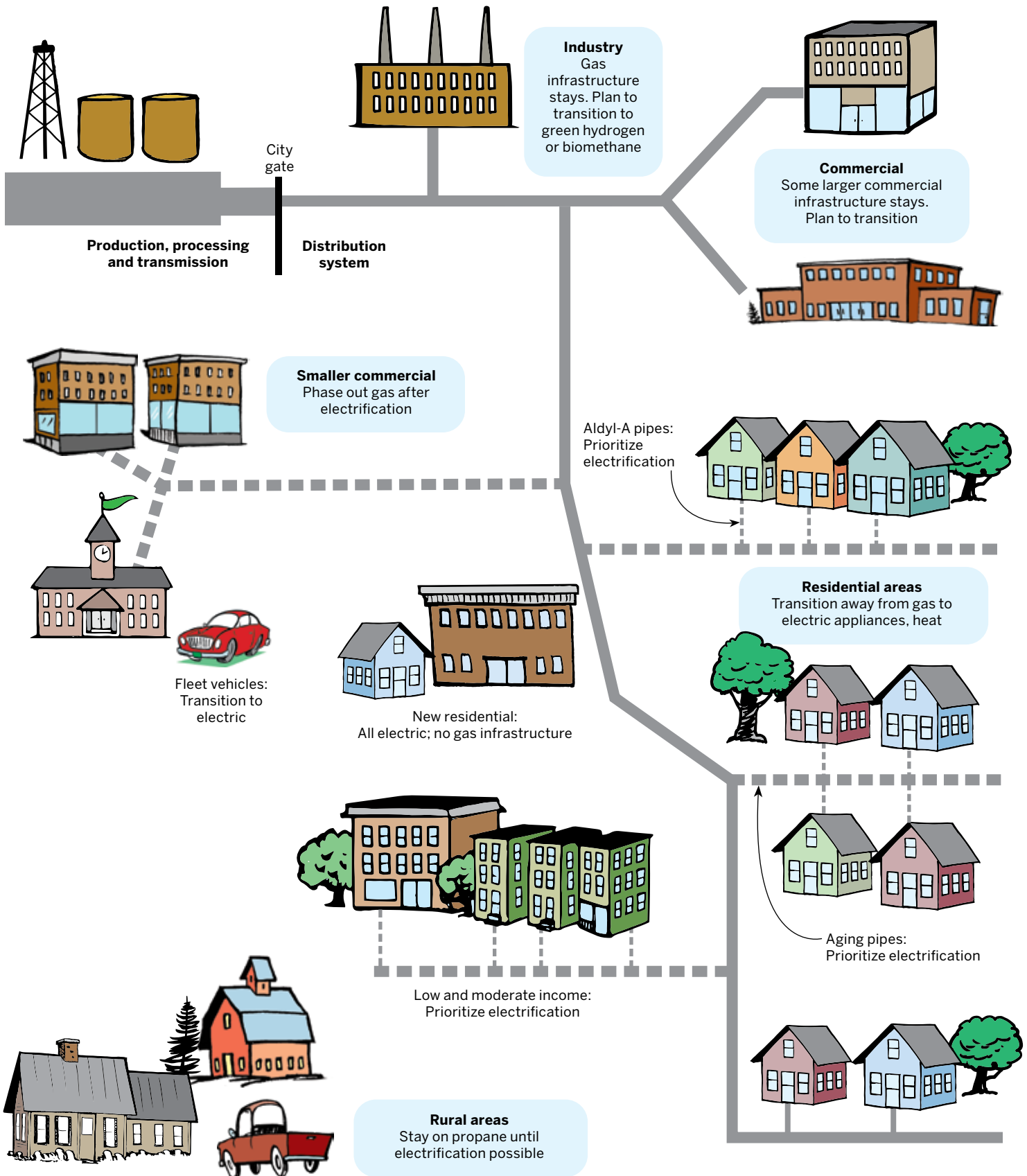
An example of how different scenarios might be layered onto a system map is illustrated in a very simplified system map in Figure 8. Regulators may ask utilities to consider:

Alternative solutions for areas where maintenance or infrastructure investment is needed to maintain reliable or safe service: In some areas, this maintenance may involve only small parts of the system, but in others, larger-scale replacements may be needed, exacerbating operation and maintenance (O&M) costs.⁴⁶

⁴⁶ Small maintenance issues can also lead to much larger projects. ConEd notes, for example, that because much of its "distribution system is low-pressure cast iron, and installation of these mains in the late 1800s and early 1900s

did not include isolation valves, much of [the] low-pressure system cannot be isolated without excavating to the main to cut and physically blocking the flow of gas." Consolidated Edison Company of New York, 2019, p. 37.

Figure 8. Illustrative alternative scenarios



Options to serve specific areas depending on demand trajectories: For example, in areas where demand is increasing due to augmented industrial development, the utility may want to consider maintaining infrastructure or adding infrastructure needed to support fossil gas alternatives. In other areas where demand is decreasing due to efficiency and electrification, the utility may consider retiring infrastructure instead of costly upgrades.

Analysis of customer base and how best to serve specific customer groups: Low- and moderate-income customers, in particular, may be burdened by rising gas costs or stranded assets and might benefit from more rapid electrification to decrease their energy burden.

Identification of areas where district energy systems might be employed: District energy, which involves providing heating or cooling to multiple sites from a large-scale source, could more efficiently serve customers and decrease utility expense.

Options for customers in less densely populated areas: Existing or new infrastructure in these areas likely has a lower use and may therefore be more costly to maintain.

Delineation of areas with all-electric building requirements: These areas may not need gas service in the first place or may become areas with more dispersed service that is less cost-efficient to maintain.

By asking utilities to illustrate and consider these various elements, regulators ensure that the utility builds scenarios that address current and changing circumstances. Providing information about the system in this manner can also facilitate discussion with stakeholders about building alternative scenarios to meet needs. For example, scenario analysis may help the utility identify areas where significant investment would be needed to continue safe and reliable service. In these cases, the utility may want to consider working to electrify whole neighborhoods and then retiring the gas distribution network,

rather than putting large amounts of capital into maintenance or upgrades that may become underutilized in the future.

Utilities with large areas of decreasing residential demand may see opportunities to focus on industrial service while phasing out increasingly expensive residential service. This type of scenario analysis will assist utilities and regulators to identify potential stranded costs before they are incurred, in particular as their impact may be felt by an even smaller customer base.⁴⁷

Exogenous factors may influence the utility's scenario building. For example, some jurisdictions are now requiring all new buildings to be all electric. Regulators can ask the utility to consider where it is expecting new builds and how it can limit expanding or upgrading infrastructure, which would almost certainly result in stranded costs in those areas. Regulators may want the utility to consider whether providing existing customers in those areas incentives to electrify would be more cost-effective than maintaining infrastructure for a decreasing customer base. The utility may also consider anticipated changes that may affect the economics or viability of its scenarios, including carbon pricing, increased GHG reduction requirements or more stringent appliance standards.

Model Scenarios

Once the utility has developed a wide range of scenarios, regulators can require the utility to model these scenarios for reliability, safety, cost, carbon impact, risk (including risk of stranded assets) and resiliency.⁴⁸ The scenario development, modeling and modeling results can be open and transparent to regulators and stakeholders. We recommend that regulators require gas utilities to accept input on the scenarios they have developed and to either model stakeholder-proposed scenarios or make modeling programs available to stakeholders to do so. The results of the scenario analysis will form the basis for the utility's action plan and long-term plan.

47 Existing incentives may run counter to utility proposals to reduce infrastructure and service to some areas. For example, the EPA's Natural Gas STAR Methane Challenge has the laudable goal of reducing emissions but does so by incentivizing the replacement of a certain percentage of pipeline in need of upgrade. U.S. Environmental Protection Agency. (2020, July 14). *Natural Gas STAR Methane Challenge Program: BMP commitment option technical document*. https://www.epa.gov/sites/production/files/2020-07/documents/mc_bmp_technicaldocument_2020-07.pdf. Regulators need

to ensure that utilities consider the big picture in decisions about pipeline replacement or maintenance.

48 Regulators will want to ensure that utilities are using models that can adequately address changing circumstances and assumptions. Regulators should ask utilities to explain their rationale for choosing a particular model and should seek input from outside experts and stakeholders about whether the model is adequate or the utility should consider other options instead.

Some broad trends can inform this analysis. Decreased demand will mean fewer customers on the utility's system with attendant challenges for sharing continued costs. Relatedly, increased electrification or electrification mandates may require a harder look at the utility's continued infrastructure investment in certain areas to reduce the possibility for stranded costs. Regulators might want to include specific requirements for utilities to consider in this analysis. For example, regulators might mandate that utilities consider investment in additional infrastructure on a level playing field with other alternatives, such as non-pipeline alternatives (NPAs) discussed in Section IV. Regulators can ensure that utilities consider whether scenarios meet both immediate (three to five years) and long-term (15 to 20 years) needs. In other words, utilities' analyses of alternative scenarios can address whether immediate steps are consistent with longer-term goals and conditions. The utility's scenario analyses can also include an assessment of system resiliency. As noted above, regulators may require the utility to outline any historical issues it has had with its system, such as delivery problems due to weather events or problems with either physical or cybersecurity. The utility can consider these historical problems and include anticipated risks. Extreme temperatures, humidity, storms, rising sea levels and combinations of these factors may affect gas systems in the future.⁴⁹ Supply itself may be limited due to insufficient water for gas production, weather events that affect delivery, or other changes that affect production. In addition to historical data regarding security issues, regulators can request the utilities to identify potential issues or vulnerabilities and the risk they pose to system resiliency.

Consider Transition Planning

Consideration and modeling of scenarios based on different conditions is important even if the utility does not anticipate making immediate changes based on these trends.⁵⁰ Even without significant exogenous factors, demand for gas is likely to be lower due to energy efficiency alone; one study notes that even in a scenario with no building electrification, energy efficiency will result in residential gas use decline of 25% by 2050.⁵¹ If widespread electrification occurs, residential gas use could decrease more than 90% by 2050.⁵² Other factors may have similar impacts or compound decreases in gas demand. Regulators need to have an understanding of what different circumstances will mean for the gas utility and its customers and available options to address those changes. To address this need, regulators can build on the gas utility's planning efforts by asking the utility to add layers of transition considerations to planning efforts. The analysis of alternative scenarios to meet changing demand may already include some of this work. In addition, regulators can ask utilities to consider other means by which the gas system may evolve, including meeting end uses in new ways, infrastructure contraction, and financial and funding tools to facilitate a transition.

Consideration of New Options for Meeting End Uses

In the face of climate science and attendant state and local government greenhouse gas reduction goals and policies, as well as customers' ability to choose from various options to meet needs, regulators might want to consider requiring utilities to use an end-use-oriented planning process. Utilities utilizing this approach would be able to more easily consider various options available to meet end uses, including

49 ConEd, for example, is "formally studying the risk that climate change poses to [its] energy-delivery systems, and is looking to identify ways to further enhance system resiliency." The company's study of climate change impacts will include considerations of "temperature, humidity, precipitation, sea level, major events and multi-hazards." Consolidated Edison Company of New York, 2019, p. 28.

50 Some gas companies are still forecasting at least modest increases in demand. See Intermountain Gas Co. (2019). *Integrated resource plan: 2019-2023*. https://www.intgas.com/wp-content/uploads/PDFs/commission_filings/IRP-Write-Up-Book-2019.pdf; and Cascade Natural Gas Corp. (2020). *2020 integrated resource plan*. <https://www.cngc.com/>

[wp-content/uploads/PDFs/IRP/2020/oregon/2020-Integrated-Resource-Plan.pdf](https://www.vermontgas.com/wp-content/uploads/PDFs/IRP/2020/oregon/2020-Integrated-Resource-Plan.pdf). By contrast, Vermont Gas Systems is "planning for loss of load and attrition while balancing the needs of current customers." Vermont Gas Systems. (2021). *Integrated resource plan*. <https://www.vermontgas.com/wp-content/uploads/2021/01/2021-01-15-VGS-Integrated-Resource-Plan-including-Attachments-00306267-2xE4196.pdf>

51 Gridworks. (2019). *California's gas system in transition: Equitable, affordable, decarbonized, and smaller*, p. 1. https://gridworks.org/wp-content/uploads/2019/09/GW_Calif-Gas-System-report-1.pdf

52 Gridworks, 2019, p. 1.

both gas and electricity, and contributions of demand-side management.⁵³

Although fossil gas service has never been universal⁵⁴ — fossil gas has faced competition from other fuels, such as electricity, propane, heating oil and wood⁵⁵ — where a utility has been given a utility franchise to serve a defined service area, it may have obligations to connect customers and to serve their energy needs.⁵⁶ By engaging in end-use-oriented planning, utilities could address areas where gas service is no longer competitive with alternative means to meet end uses or where customers desire other options. Changed circumstances, including climate change mandates, and decreased demand due purely to increased efficiencies, performance and health benefits of electrification require regulators and gas companies to reconsider the obligation to maintain a gas system that serves all customers. Instead, regulators and gas companies can develop transition pathways to ensure that the move away from widespread natural gas use is done in a manner that eases the transition for customers and utilities.

Transition pathways could guide the utility to serve customers with alternative fuels that do not require additional investment in infrastructure. The utility could design rates to disincentivize new customers, including declining to socialize the costs of service line extensions. Customers could be given assistance or other incentives to electrify in areas where it is no longer economical to conduct maintenance or upgrades on aging systems. Legislatures could also be called upon to clarify the gas company's role in light of other policy requirements.

Options for Infrastructure Contraction

Regulators can require utilities to consider options for contracting gas infrastructure. Utilities can begin to rethink their systems to align with changing demand in several ways.

First, utilities can use the information outlined in their scenario analyses to identify areas where gas distribution service can be reduced or eliminated. As noted above, areas that are seeing significant electrification or decreased gas demand due to efficiency measures may be candidates for complete electrification of end uses that currently use gas⁵⁷ and attendant retirement of gas service. Regulators may ask gas utilities to look for areas with increased electrification and areas where significant pipeline maintenance or replacement is needed, to determine where there are opportunities to decrease the size and cost of underutilized parts of the system by planning for a managed phase-out of gas service to those areas.

Second, utilities can delay the need for investment in infrastructure, and potential stranded costs, by taking measures to use the system more efficiently and by considering NPAs, discussed in Section IV. Transmission pipelines can be downrated to distribution pressures in areas where consumption has fallen, reducing future maintenance costs.⁵⁸ Aldyl-A, unprotected steel, cast iron and other leak-prone pipes slated for replacement are generally clustered in certain areas. Considering these areas as candidates for electrification will avoid the need for costly and disruptive pipeline replacement.⁵⁹ Regulators can call upon gas companies to include a section in gas plans that includes information about these needs and considers other methods to reduce investment in infrastructure. This section may include possibilities for immediate implementation or ideas for pilot projects to test new approaches.

Third, utilities and regulators can reconsider line extension policies, discussed in more detail in Section V on rate-making. Each extension requires the utility to expend capital to connect a new customer. That connection may be only a service line stemming from a main, along with the regulator and meter. Or, in the case of larger new

53 For a discussion of procurement best practices, see Shwisberg, L., Dyson, M., Glazer, G., Linvill, C., & Anderson, M. (2020). *How to build clean energy portfolios: A practical guide to next-generation procurement practices*. RMI. <https://rmi.org/how-to-build-ceps>

54 National Association of Regulatory Utility Commissioners. (2017). *Report of the NARUC task force on natural gas access and expansion*. <https://pubs.naruc.org/pub.cfm?id=8F38EF6F-D44F-80A0-578C-CF1610C47520>

55 National Association of Regulatory Utility Commissioners, 2017.

56 Bilich, A., Colvin, M., & O'Connor, T. (2019). *Managing the transition: Proactive solutions for stranded gas asset risk in California*. Environmental Defense Fund. https://www.edf.org/sites/default/files/documents/Managing_the_Transition_new.pdf

57 Where total electrification is not immediately possible, utilities might also consider providing propane service for limited uses.

58 Gridworks, 2019, pp. 3, 12.

59 Gridworks, 2019, pp. 3, 12.

developments or customers, the utility may need to extend the system significantly to include a network of mains and service lines.⁶⁰ Carbon reduction goals may render many of these investments stranded.

Analysis of Financial Tools and Funding to Ease the Transition

A utility plan considering these options must be accompanied by analysis of the financial impact on customers of different transition pathways, including tools to ease impacts to customers. Possibilities to address these impacts are discussed in more detail in Section V, which considers opportunities to use rate-making to facilitate the transition. This section addresses how bills are expected to change and how a utility's gas plan can respond to those changes.

A customer's bill includes charges for supply and delivery, along with taxes and fees. These costs vary depending on numerous factors, including customer base and service area. That said, fluctuations in the cost of supply affect only part of the bill,⁶¹ whereas cost of delivery makes up a significant part of a customer's bill. This charge includes O&M costs, capital expenditures to provide service and expenses required to run the gas company itself. Regulators can consider this impact when considering utility plans to upgrade or expand infrastructure. Taxes and fees, including gross receipts tax, sales tax, franchise fees and the company's income and property taxes, add to those expenses.⁶² In short, even if gas itself remains inexpensive, customer bills may be high when utilities are required to maintain or upgrade existing infrastructure. This impact will be exacerbated as customers electrify some end uses or exit the system altogether, as those infrastructure costs will need to be divided among fewer customers.

Regulators may therefore require that gas utilities include a discussion of mechanisms to alleviate the impacts to LMI customers in their planning processes. One step, as discussed above, is to consider areas where electrification or other zero- or low-carbon alternatives may benefit LMI customers and to provide incentives for those customers to leave the gas system first. In addition, regulators might ask utilities to consider programs to help LMI households that would otherwise face barriers to electrification, including the upfront expense of purchasing new appliances or transitioning to electric heat, related expenses of any electric system upgrades or lack of space in smaller homes or apartments for heat pumps or other alternatives.⁶³ Customers who do not own their homes or apartments also may not be able to make such upgrades without landlord approval, and landlords who are not paying the bills may not be incentivized to make such changes. To alleviate this burden, regulators could require utilities to employ energy transition coordinators who work specifically with LMI customers or seek funding for public utility commissions to provide similar assistance. The stakeholder process can provide valuable input for those considerations. That discussion will in turn be enriched where regulators ensure that the utility discloses potential impacts and provides data about system changes to stakeholders.

D. Create Short-Term Action and Long-Term Transition Plans

We recommend that regulators require two outputs of a gas transition plan: a short-term action plan (covering the next three to five years) that includes immediate next steps, and a long-term view (15 to 20 years) of the utility's system.

60 This expansion may involve costs beyond the pipelines themselves, including right-of-way costs. "NMGC's pipelines and facilities across the state must traverse public, private, and Native American jurisdictions. Based on historical experience, right-of-way (ROW) costs are one of the fastest growing costs of new gas facility construction. Access to facilities on public lands is also becoming increasingly difficult and conditioned with limitations that restrict necessary evaluation and maintenance activities and contribute to increased costs." New Mexico Gas Co. (2020), *2020 integrated resource plan*, p. 21. <https://www.nmgco.com/userfiles/files/2020%20IRP%20Report.pdf>

approximately divided into thirds: Delivery costs represented 37%; supply, 30%; and taxes and fees, 33%. Consolidated Edison Company of New York, 2019, p. 44.

62 Consolidated Edison Company of New York, 2019, p. 44

63 Sunderland, L., Jahn, A., Hogan, M., Rosenow, J., & Cowart, R. (2020, May). *Equity in the energy transition: Who pays and who benefits?*, pp. 46-49. Regulatory Assistance Project. <https://www.raponline.org/knowledge-center/equity-in-energy-transition-who-pays-who-benefits/>

61 For example, in New York, these three segments of the bill can be

Both these plans can be informed by the results of the utility's scenario analysis; the utility can use that analysis to determine which course of action best meets its objectives at the least cost and risk for the utility and its customers. The action plan will then spell out steps the utility must take in the near term to begin to implement that course of action. The long-term plan can provide a longer vision of where the utility is headed to ensure that it does not take actions in the near term that are incongruent with long-term objectives. The utility can iterate and update both of these plans in its next planning cycle.

As regulators consider a changing energy system, planning is a "no regrets" tool that can ensure they have the information

they need to make decisions about utility gas filings. While no plan can predict the future, a sound plan will account for a reasonable array of prospective events and outcomes and assess tactics to best prepare for them. In addition, a gas planning process can provide regulators an opportunity to incorporate stakeholder perspective and input. Finally, regulators can design the planning process to require utilities to consider a range of transition pathways and attendant scenarios in an open and transparent process to ensure that the utility is moving forward with well-vetted and robust plans. Regulators can complement planning efforts through energy efficiency and electrification programs, which we discuss next.



IV. Enhance Energy Efficiency and Electrification Programs

Utility energy efficiency and electrification programs will be important elements of any gas transition strategy, and programs’ design and details can help or hamper gas transition plans.⁶⁴ This section discusses several key aspects of these programs and recommends changes to ensure that these programs are operating in concert with and facilitating gas transition.

In many states, utilities or other administrators run energy efficiency programs, funded by ratepayers. Improving energy efficiency is often the least-cost option and brings substantial net benefits, which include not only cost savings from reduced energy use but also cost savings for the utility, as well as lower costs of compliance with environmental regulations and reduced social costs of pollution. Energy efficiency programs address market barriers and market failures that keep consumers from making cost-effective energy efficiency investments. These programs are required to be cost-effective, and utilities evaluate the programs based on screens for cost-effectiveness administered by regulators and often required by state law. These programs can bring substantial savings for customers and benefits to society, including health benefits associated with emissions reductions. In addition, they are critical complements to a transition away from gas. Energy efficiency programs can include measures for switching from gas equipment to more efficient electric equipment. They can also complement electrification efforts by improving the economics of electrification measures.

Because of the significant benefits of efficiency programs,

it makes sense to strengthen these programs, even in states that are not yet ready to consider developing a comprehensive gas transition plan. Strengthening energy efficiency programs can be thought of as part of a “no regrets” initial effort in states that are having trouble building consensus — or even starting a discussion — about gas transition. Later, these programs can be integrated into a gas transition plan. It should also be noted, however, that in many cases these programs are not only regulatory in origin but come from more specific statutory authorizations and mandates. In such cases, regulators may not have the authority to make certain revisions to the programs because doing so would require a change in statute.

In this section, we offer recommendations for strengthening energy efficiency and electrification programs in order to unlock the cost savings and other benefits such as reduced emissions. Figure 9 on the next page depicts one estimate of emissions reductions achievable with electrified heating in residential and commercial buildings, particularly when coupled with city and state clean energy commitments.⁶⁵

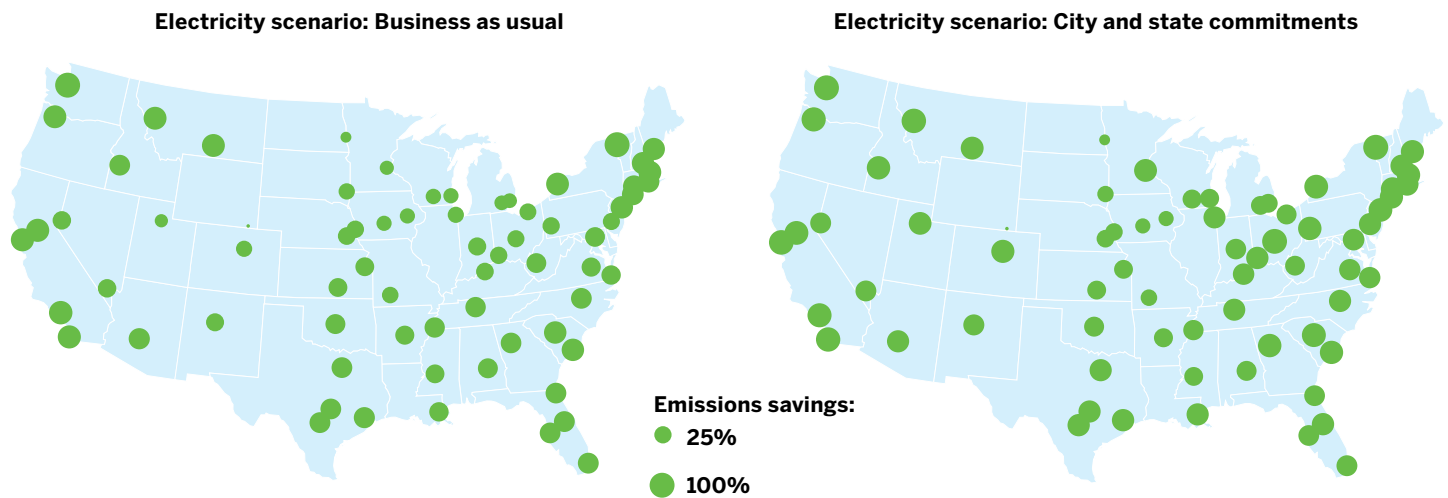
A. Reform Rules That Discourage Electrification

In many states, energy efficiency programs are governed by rules called energy efficiency resource standard (EERS) policies. As of mid-2019, 27 states had implemented an EERS policy for electricity, and a subset of 18 also had EERS policies for natural gas.⁶⁶ The policies require utilities (or, in some states,

64 This section draws on several previous RAP publications. For more detail and discussion, see Farnsworth et al., 2019; Shipley et al., 2018; and Shipley, J., Hopkins, A., Takahashi, K., & Farnsworth, D. (2021). *Renovating regulation to electrify buildings: A guide for the handy regulator*. Regulatory Assistance Project. <https://www.raponline.org/knowledge-center/renovating-regulation-electrify-buildings-guide-handy-regulator/>

65 The Gas Index, 2020. For an interactive version of the maps in Figure 9, see The Gas Index. (n.d.). *Electrification: Building electrification scenarios*. <https://thegasindex.org/electrification/>

66 American Council for an Energy-Efficient Economy. (2019). *State energy efficiency resource standards (EERS)*. <https://www.aceee.org/sites/default/files/state-eers-0519.pdf>

Figure 9. Emissions savings of switching from gas heating to traditional electric heat pumps, amplified by clean electricity

Note: Percentages represent reductions in space heating-related greenhouse gas emissions in the cities studied, comparing a business-as-usual projection for the electricity system with a scenario that includes emissions savings from city and state clean electricity targets.

Source: The Gas Index. (2020). *The United States' Natural Gas System Has a Serious Problem: It Leaks*

designated program administrators) to implement programs that improve the energy efficiency of utility customers and include mandatory targets for these programs.

Energy efficiency programs have been very effective at mobilizing efficiency and associated cost savings and benefits. Some states, however, have problematic rules that prohibit or discourage these programs from supporting switching from gas equipment to electrified substitutes, even when beneficial to do so.^{67, 68} These prohibitive rules result in gas utility energy efficiency programs that focus on replacing old and inefficient gas equipment with new more efficient gas appliances, ignoring opportunities to unlock greater benefits from switching to electrified appliances. Such an approach made sense in earlier decades when gas space and water heating was more efficient and environmentally friendly than the electric alternative — which at that time usually meant electric

resistance heating drawing power from a coal-dominated electric grid.⁶⁹ But in recent years, electric heating technology has improved. Space and water heating can increasingly be done cost-effectively with highly efficient electric heat pumps that are powered by a decarbonizing grid.⁷⁰ In short, programs with fuel-switching prohibitions lose opportunities to support beneficial electrification.

We recommend that a first step is to remove any prohibitions on fuel switching. After that, ideally, program rules should set out principles for identifying and exploiting beneficial opportunities to switch away from gas to electrification.

More specifically, we recommend the following:

- Remove any EERS rules that explicitly prohibit or discourage fuel-switching measures.
- Implement a fuel-neutral EERS or energy savings goal,

67 For example, the policy of Energy Trust of Oregon effectively bars the program from promoting fuel switching. The program administrator states that it “does not intend its incentives to affect fuel choice.” Energy Trust of Oregon Inc. (n.d.). *4.03.000-P Fuel-switching policy*. <https://www.energytrust.org/wp-content/uploads/2016/11/4.03.000.pdf>

68 Here, the adjective “beneficial” refers to electrification that leads to positive net benefits for society. In a series of publications, RAP has proposed a working definition of beneficial electrification. Under this definition, electrification must satisfy at least one of the following conditions, without adversely affecting the other two: (1) saves consumers money over the long run; (2) enables better grid management; and (3) reduces negative environmental impacts. For more discussion, see Farnsworth, D., Shipley, J.,

Lazar, J., & Seidman, N. (2018, June). *Beneficial electrification: Ensuring electrification in the public interest*. Regulatory Assistance Project. <https://www.raponline.org/knowledge-center/beneficial-electrification-ensuring-electrification-public-interest>

69 Farnsworth, D. (2018, June 11). *Fuel-switching: We just did this in 1990, so why are we doing it again?* Regulatory Assistance Project. <https://www.raponline.org/blog/fuel-switching-we-just-did-this-in-1990-so-why-are-we-doing-it-again/>

70 Although improving, the economics of heat pumps for space heating is still an issue for cold climates, particularly when a building is not well insulated.

denominated in primary energy (Btu) or greenhouse gas emissions, rather than in units of specific fuel savings.⁷¹ A goal defined in this way will allow utilities and program administrators to look for the most cost-effective ways to save total energy used (gas plus electricity), even if that may mean increasing the amount of electricity consumed.

- Allow gas utilities to count a portion of fuel-switching measures toward efficiency targets based on the primary energy savings. Implement requirements and guidelines regarding the types of electrification measures that can be considered beneficial and that can be counted toward efficiency targets. For example, the program could require a minimum level of efficiency for heat pumps.
- Consider setting requirements within the EERS policy specifying that only specific types of measures are beneficial and thus qualify toward the target. For example, the program could require heat pumps installed through the program to be highly efficient, as determined by an expert organization like Northeast Energy Efficiency Partnerships.⁷²
- Encourage accurate and comprehensive measurement of benefits of efficiency measures. Strengthen requirements and guidelines for utilities to measure the full “layer cake” of benefits associated with measures that involve electrification, including public health benefits, such as improved air quality.⁷³ This analysis should also include an estimate of the benefits associated with operating electrified end uses flexibly; that is, the benefits of supporting grid integration of variable energy supplies such as wind and solar.⁷⁴ In addition, many efficiency programs only evaluate (or heavily weight) electricity savings accomplished in the first year of a measure. However, cost-effectiveness of some relevant measures for electrification of gas end uses, such as heat pumps for space and water heating, may be apparent only if life-cycle savings are considered, including the avoided gas infrastructure renewal costs. Therefore, it is important that benefits should be calculated in a way that reflects the full life-cycle savings of electrification.
- Review prohibitions against electric utility programs that increase load. In earlier decades, these rules were useful as a tool (albeit somewhat blunt) to restrain electric utilities from pursuing increases in inefficient end uses. Now some of these rules may stand in the way of electrification objectives, and it is time they are replaced by more finely tuned policies to promote overall efficiency and emissions reductions.⁷⁵
- Consider prohibiting any new deployment of fossil gas equipment under these programs. Given the trends outlined in Section II and the diminishing case for gas relative to electrified end uses, there is a case for focusing all programs on measures that do one of the following: (1) switch from non-electric to electrified equipment; (2) improve the efficiency of already electrified end uses; and (3) complement electrification (e.g., improvements in building insulation to improve the economics of heat pumps). This decision to prohibit deployment of gas equipment under efficiency programs will depend on the characteristics of the jurisdiction and the evolving costs of heat pumps and other electric alternatives, among other factors. The case for prohibiting new gas equipment

71 New York, Wisconsin and Massachusetts have fuel-neutral targets in their EERS policies. For example, see Public Service Commission of Wisconsin, Docket No. 5-FE-101 (PSC Ref.#: 343909), Quadrennial Planning Process III, Final Decision, June 6, 2018. apps.psc.wi.gov/vs2015/ERF_view/viewdoc.aspx?docid=343909. New York state in 2018 adopted a statewide cumulative annual site energy savings target that is defined in Btu. See New York State Research and Development Authority & New York Department of Public Service. (2018). *New efficiency: New York*. www.nyserda.ny.gov/About/Publications/New-Efficiency; and Dennis, K., Colburn, K., & Lazar, J. (2016). *Environmentally beneficial electrification: The dawn of ‘emissions efficiency.’* Regulatory Assistance Project. <https://www.raponline.org/knowledge-center/environmentally-beneficial-electrification-dawn-emissions-efficiency/>

72 See Northeast Energy Efficiency Partnerships. (n.d.). *CCASHP specification & product list*. <https://neep.org/ASHP-Specification>

73 See Lazar, J., & Seidman, N. (2019). *Value added: Measuring the health benefits of the “layer cake.”* Regulatory Assistance Project. <https://www.raponline.org/blog/value-added-measuring-the-health-benefits-of-the-layer-cake/>; and Lazar, J., & Colburn, K. (2013). *A layer cake of benefits: Recognizing the full value of energy efficiency.* Regulatory Assistance Project. <https://www.raponline.org/knowledge-center/a-layer-cake-of-benefits-recognizing-the-full-value-of-energy-efficiency/>

74 New York and California now include time- and location-specific avoided costs in cost-effectiveness analyses for energy efficiency programs. Shipley et al., 2021.

75 Farnsworth et al., 2019.

deployment is clear in places where electrification clearly meets the criteria for being beneficial.⁷⁶ In some cases, electrification is not yet beneficial. For example, cost-effective electrification of space heating is still difficult in cold climates, where there may still be justification for continued replacement of old gas furnaces with new more efficient ones that use the same fuel. We suggest that regulators should keep a keen eye on these trends as costs of electrification continue to fall rapidly and capabilities improve.

B. Expand and Coordinate Programs in Order to Reduce Costs and Improve Equity

Regulators can use finance and incentive policies to align the beneficial outcomes of energy efficiency programs, building shell improvements and equitable electrification with efforts to move away from reliance on gas resources. First, regulators can structure energy efficiency programs and incentives to encourage building shell improvements that support efficient electrification. Second, regulators can design energy efficiency programs to target retirement of inefficient gas appliances.

Promote Building Shell Improvements in Coordination With Heating System Replacement

Investing in building shell improvements and coordinating that investment with heating system replacement can improve the economics of electrification measures so that additional investments in building heating systems can be more effective at lower cost.⁷⁷

Well-insulated and well-sealed buildings are easier to heat and can be served by smaller, less expensive heat pumps. In addition, because such buildings also retain heat, they can be preheated at off-peak times when renewable energy is available or when electricity is less expensive and thereby

produce lower emissions on the grid.

We recommend that regulators expand programs for building shell improvements, including weatherization, insulation and better sealing.

We also recommend coordination of building shell improvement with heating system replacement. Building owners may face difficulties in financing building improvements and electrification simultaneously. This situation may exacerbate equity concerns if LMI customers are unable to pursue weatherization in conjunction with electrification. For example, take the case of installing a heat pump (large enough to heat a poorly insulated house) for \$14,000. Suppose installation of \$2,000 in building shell improvements reduces the heat pump size requirement and lowers the heat pump cost to \$8,000. In this example, the combined efficiency measure plus heat pump costs \$4,000 less than the heat pump alone.

Coordinating these efforts will be especially important for LMI and multifamily properties that often have poor insulation and building shells in need of maintenance. For example, the California Low-Income Weatherization Program is a comprehensive retrofit program that packages electrification measures with energy efficiency and solar to help owners and tenants save money and reduce GHG emissions. On average, projects in this program have seen energy costs reduced 24%. In cold climates, weatherization of the building envelope may be essential to making a heat pump effective at both saving energy and maximizing comfort.

Design Energy Efficiency Programs to Target Retirement of Inefficient Gas Appliances

A major barrier to increasing building efficiency is that upfront costs for heat pumps and other electric appliances can keep customers from unlocking long-term benefits of those options. Even where it is in the consumer's own interest to replace old and inefficient gas equipment with more efficient

76 For more information on the concept of beneficial electrification, see footnote 68.

77 This section draws on Shipley et al., 2021.

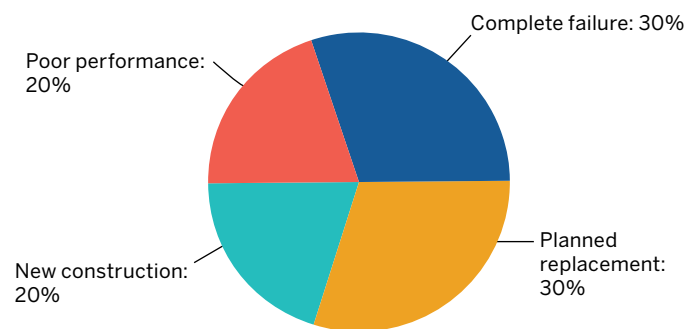
electric alternatives, often the costs are very front-loaded while the benefits accrue over many years.⁷⁸ LMI households often have older and less efficient appliances and lack financing options, financial flexibility and information. Renters generally do not have the time to recover investments or access to capital that owners might have.

Energy efficiency programs in different states offer various types of incentives, including financial incentives for customers to purchase certain types of products, appliances and equipment; building audits to identify cost-effective energy efficiency upgrades; help with installation costs for efficient equipment; training for third-party building engineers and contractors; and educational communication to customers to increase their knowledge of the benefits of energy efficiency. Incentives can come from utilities (in the form of rebates to consumers or upstream incentives to manufacturers or retailers), third-party energy efficiency providers or governmental agencies or programs (through rebates, loans or tax incentives). Policymakers and regulators should consider mobilizing additional resources to support targeted energy efficiency programs.⁷⁹

Several New England states have incentive programs to promote switching to heat pumps. Maine has incentives that target replacement of residential oil heating with electric heat pumps, providing residential and commercial customers with rebates to lower the upfront cost.⁸⁰ Massachusetts has had incentive programs for heat pumps since 2015.⁸¹

We recommend designing incentive programs to target retirement of gas equipment, with particular focus on

Figure 10. Reasons for purchasing a water heater



Source: U.S. Department of Energy. (2009). *New Technologies, New Savings: Water Heater Market Profile*

encouraging replacement before an existing gas furnace or water heater fails. In the case of water heaters, unplanned replacements due to poor performance or failure have been found to represent half of all purchases (see Figure 10).⁸² In an emergency situation, consumers often have little time or flexibility to investigate newer electrified options, including the electrical panel and circuit upgrades that may be required, and will simply install a new gas appliance as a replacement. Well-targeted early retirement programs for gas appliances would identify likely-to-retire opportunities based on age and level of efficiency and could be designed so that early retirements are done in shoulder seasons, when heating contractors, electricians and plumbers have time and capacity.⁸³ Such programs could help identify situations where electrical upgrades are also needed and ensure there is sufficient time for electric service upgrades.

78 Energy efficiency program designers have long grappled with similar problems. As a result, there is a significant amount of experience regarding possible solutions to mitigate upfront capital costs. Beyond utility and governmental incentives in the form of grants and rebates, there are other financing approaches, including on-bill financing, property tax financing (also known as property assessed clean energy financing, or PACE), performance contracting and energy efficiency mortgages. These types of programs can be particularly effective to unlock beneficial electrification measures for consumers who may balk at the upfront capital costs but otherwise have the ability to pay. See Hayes, S., Nadel, S., Granda, C., & Hottel, K. (2011). *What have we learned from energy efficiency financing programs?* (Report No. U115). American Council for an Energy-Efficient Economy. <https://www.aceee.org/research-report/u115>

79 These dedicated resources might come from a system benefits charge or revenue from a carbon emissions cap and trade program.

80 Rosenow, J., & Farnsworth, D. (2019). *Decarbonising heat in buildings: A comparison of policies in Germany and New England*. Regulatory Assistance Project. <https://www.raponline.org/knowledge-center/decarbonising-heat-in-buildings-comparing-policies-germany-new-england/>

81 The Mass Save program is run by the utilities and overseen by the Department of Public Utilities and the Energy Efficiency Advisory Council.

82 U.S. Department of Energy. (2009). *New technologies, new savings: Water heater market profile*. https://www.energystar.gov/ia/partners/prod_development/new_specs/downloads/water_heaters/Water_Heater_Market_Profile_Sept2009.pdf. Although this particular survey is more than a decade old, it is still relevant: Consumer habits tend to change slowly when it comes to long-lived equipment.

83 For more discussion see Farnsworth et al., 2019.

C. Unlock Non-Pipeline Alternatives

Energy efficiency and electrification programs can be deployed to avoid unnecessary expansions or upgrades of gas infrastructure, such as new or bigger mains. For example, an expected increase in customer demand can potentially be met through building envelope improvements and installation of electric heat pumps in the premises of new and existing customers, instead of investments in expanded pipeline capacity. Doing so may result in lower costs and lower emissions, depending on local conditions. These non-pipeline alternatives are analogous to the non-wires alternatives in the power sector, where lower-cost measures such as energy efficiency substitute for expansion of distribution and transmission assets. In fact, the use of NPAs in the gas sector is currently being developed in New York, the same state that pioneered non-wires alternatives for electric utilities.⁸⁴

In New York, the interest in developing a framework for NPAs was partly in reaction to utility claims that supply constraints would prevent the utilities from being able to provide gas service to new customers.⁸⁵ In response, the New York Public Service Commission issued an order that requires gas utilities to develop a new framework for identifying, choosing and implementing NPAs and to formalize this framework as part of utility planning and operations. In New York, the interest in NPAs stems, in part, from a recognition that the costs of peak period gas supply are very high and that demand-side measures are likely to be very attractive in comparison.

Non-pipeline alternatives are good solutions to decrease dependence on gas and allow for opportunities for electrification. NPAs promise cost savings for consumers and utilities and benefits for society. NPAs can be part of a gas transition plan,

but the potential benefits make them worthy of consideration even for states that have not yet committed to a plan.

An initial small step would be to look for ways in which existing energy efficiency and electrification programs can help manage gas system infrastructure needs, on a case-by-case basis. As New York is finding, however, a more comprehensive framework is needed to take advantage of the potential benefits of NPAs. First, as part of the planning process, the utility should consider a full range of NPAs to meet any new demand or expected need for upgrades. Second, the utility should develop consistent criteria to evaluate different options for each specific case, allowing for comparison of the full societal benefits and costs of various traditional and NPA options. In the New York case, the commission called for the utilities to establish criteria “including reliability, practicality, environmental impact, avoided need for infrastructure investments, cost allocations over the appropriate time frame, emissions, and local community impacts.”⁸⁶ That process in New York is still under development as of the time of this writing.

D. Target Electrification Geographically to Enable Gas Infrastructure Retirement

As discussed above, states that commit to decarbonization and a gas transition planning process will likely arrive at plans that call for a gradual reduction in gas usage — and thus gas distribution network utilization. For example, a California Energy Commission report forecasts that the lowest-cost pathway to meet the state’s climate objectives will include high levels of building electrification and dramatically reduced gas consumption.⁸⁷ This outcome raises questions about how the size of the gas distribution network changes in coming decades. The California report points out that, at least in principle,

84 New York Public Service Commission, March 19, 2020.

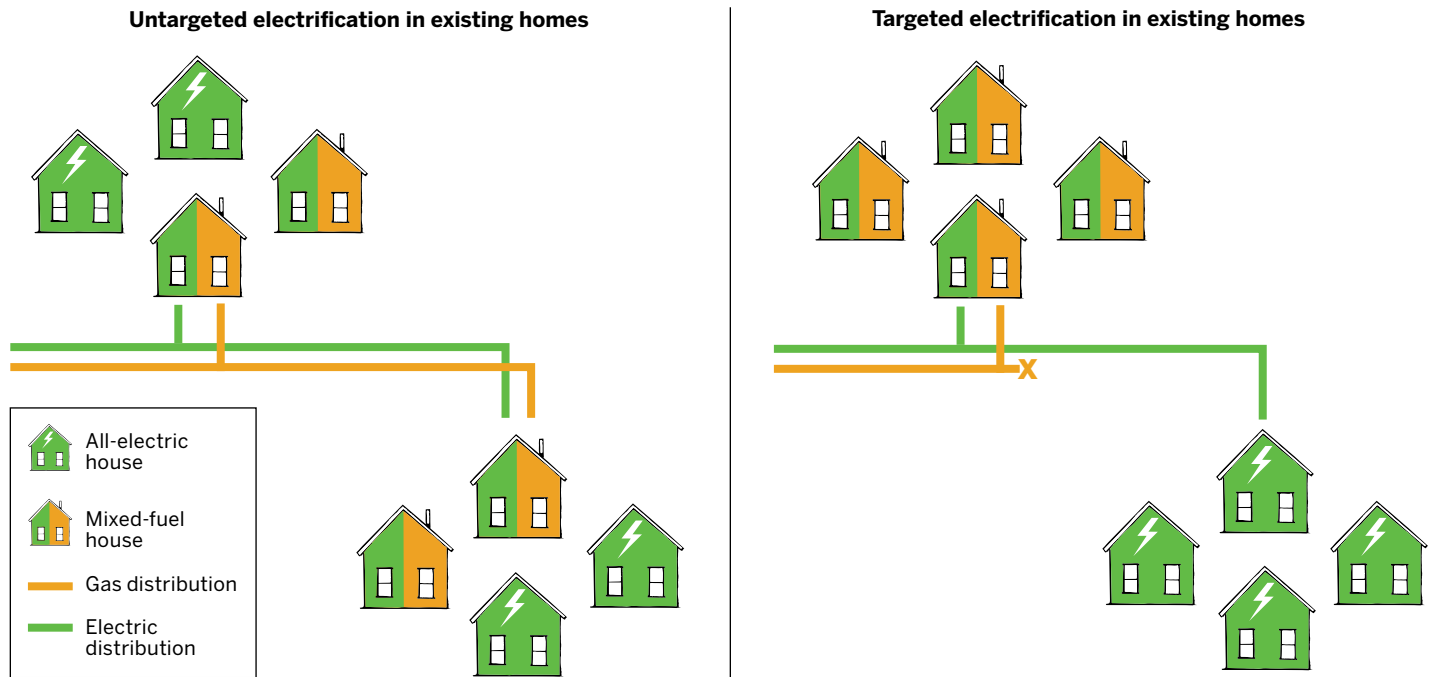
85 New York Public Service Commission, March 19, 2020.

86 New York Public Service Commission, March 19, 2020, p. 7. For discussion of how the utility can develop these types of criteria into a detailed screening

process for NPAs, see Hopkins, A., Napoleon, A., & Takahashi, K. (2020). *Gas regulation for a decarbonized New York: Recommendations for updating New York gas utility regulation*. Synapse Energy Economics, Inc. <https://www.synapse-energy.com/project/gas-regulation-decarbonized-new-york>

87 Aas et al., 2020.

Figure 11. Geographically targeted electrification to reduce gas infrastructure needs



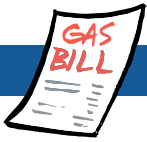
Source: Graphic concept inspired by Aas, D., Mahone, A., Subin, Z., Mac Kinnon, M., Lane, B., & Price, S. (2020). *The Challenge of Retail Gas in California's Low-Carbon Future: Technology Options, Customer Costs, and Public Health Benefits of Reducing Natural Gas Use*; graphic modified by RAP.

managing the transition carefully by targeting electrification efforts can lower the costs associated with the gas distribution system that remains in place during and after the transition. A smaller network should have lower O&M costs.

The main idea behind targeted electrification is to retire geographic areas of the distribution grid, area by area. First, an area of the distribution network is selected or targeted for retirement, and then an electrification program is implemented, with the goal of rapidly electrifying all gas usage in that particular area (see Figure 11⁸⁸), before moving on to the next area. Such an approach should allow a part of the distribution network to be retired, obviating the need for continued O&M spending in that area. In contrast, electrification efforts that proceed in a nontargeted, scattershot

fashion — with, say, neighboring buildings undergoing electrification in different years — will leave the distribution network in place at its current size for longer, with little reduction in O&M costs, despite the reduced gas throughput. This would leave fewer gas-using customers paying a greater share of system costs, creating upward pressure on rates. The California report suggests that a targeted approach could lead to substantial O&M savings and help manage the costs of a gas transition, although the authors caution that the cost savings will depend on careful study of suitable footprints for targeting. For that reason, states committed to gas transition should consider implementing targeted electrification and gas distribution retirement pilots early in the process.

88 Graphic concept inspired by Aas et al., 2020, Figure ES-2; graphic modified by RAP.



V. Reform Gas Rate-Making

Rate-making provides a distinct set of tools that regulators and utilities can use to manage the transition away from fossil gas. At the same time that gas planning provides an opportunity for regulators, utilities and stakeholders to take a broad and long view of a system in transition, and energy efficiency and electrification programs offer a way to facilitate that transition, rate-making can lower short-term barriers and enable an equitable and efficient long-term transition. This section provides background on gas utility rate-making, followed by recommendations for changes to current practices to (1) mitigate rate impacts in coming decades; (2) ensure costs are spread fairly and prices provide efficient customer incentives; and (3) reform the utility business model so that it relies less on continued capital expansion and more on customer objectives and public policy goals.

Rate-making for gas utilities follows the same high-level principles as rate-making for other utilities:

- Effective recovery of the revenue requirement, revenue stability and access to reasonably priced capital.
- Customer understanding and acceptance and bill stability.
- Equitable allocation of costs and avoidance of undue discrimination.
- Efficient forward-looking price signals to optimize usage.⁸⁹

These principles rarely all pull in the exact same direction and must be balanced appropriately and considered in the context of broader public policies. Furthermore, the overarching goal of economic regulation of natural monopolies is to mimic the pricing discipline imposed by competitive markets.

The application of these principles may be different for gas utilities because of issues that arise in the supply and delivery of gas. Technology and engineering constraints, as well as

resulting cost considerations, are naturally different than for other utilities, although there are frequent analogs. Both electric and gas utilities have peak capacities for every segment of the system: transformer limitations and line carrying capabilities for electricity; pipeline capacity for gas. Similarly, safe and effective operation requires that each system segment must stay within certain limits, measured by voltage and frequency for electricity and pressure for gas.

The steps of the rate-making process are the same for an investor-owned gas utility as for other investor-owned utilities:

1. Determine the revenue requirement.
2. Allocate costs to the different customer classes.
3. Design rates that customers ultimately pay.

Every jurisdiction has a long history behind the current rate-making practices for each of these steps for gas utilities. As with planning and program design, rate-making practices for gas utilities must be reexamined and reformed to deal with new realities.

A. Lower Rate Base and Decrease Risk of Rate Impacts

Lowering rate base, one of the key inputs to the capital payment portion of the revenue requirement, is a key way to prevent medium- and long-term rate impacts and reduce the risk of stranded costs. Doing so gradually in the next decade can prevent much bigger rate impacts in coming decades, while providing valuable regulatory flexibility and reducing the need to find outside funding sources.

Under traditional cost of service regulation, the revenue requirement for a gas utility is composed of many different

⁸⁹ A summary of the eight principles laid out in Bonbright, J. C. (1961). *Principles of public utility rates*, p. 291. Columbia University Press. <https://www.raponline.org/knowledge-center/principles-of-public-utility-rates/>

elements. At the highest level, this can be divided into three categories:

- Operation and maintenance expenses.
- The capital payment, composed primarily of depreciation expense and the return on investment.⁹⁰
- Taxes.

Of the components of the revenue requirement, the element of today's rates that has the biggest impact on medium- and long-term rates is the capital payment because of the way these payments are structured over long periods of time. Many utility capital investments are designed to last a long time, many decades, and cost recovery is typically spread over the asset's estimated useful life. In contrast, operating expenses are items that may change year to year, such as labor costs and fuel purchases.⁹¹ If a utility stopped its operations tomorrow, these are the costs that could be wound down relatively quickly, although certain expenses may be governed by contracts of various lengths. In contrast, utilities pay many different kinds of taxes, as well as franchise fees to local governments in many jurisdictions. Some of these taxes vary from year to year, such as sales and labor taxes associated with O&M expenses. Other taxes are linked to capital assets or land, such as property taxes, and income taxes are linked to annual net income, which is most strongly tied to the return on capital investments.

Several variables determine the total amount of the capital payment in an annual revenue requirement. Depreciation expense,⁹² sometimes called the return of a capital investment, is the estimated annual loss in value of the utility's capital investments. The return on a capital investment is determined by two major factors: the rate of return and the rate base. The rate of return is primarily defined by the interest rate on debt and the return on equity due to shareholders. The rate base is defined as the original cost of utility capital investments minus accumulated depreciation over the years that capital assets have been in service, often with other accounting adjustments.⁹³

In a typical gas utility rate case, many older capital assets will still be in rate base, although at a much lower net value than their original cost, since they have substantially depreciated. A utility may still be using assets that are fully depreciated for rate-making purposes, which add nothing to the capital payment but may have substantial maintenance costs or other issues because of their age. For new capital investments in the existing system (e.g., replacing an old main with a new state-of-the-art pipe), the entire cost of the investment, assuming it is approved by the regulators, goes into rate base.

For new extensions of the gas system, a portion of the new capital investment is frequently paid for by the newly connected customers, whether that is the service line for a specific customer or the distribution main that is most frequently shared among many customers. These terms are laid out in line extension tariffs. Any upfront payment from those customers is deducted from the original cost of the investment because the utility is not financing that portion of the investment. As a result, the size of those customer contributions directly influences the rate base. For these new extensions, the remaining portion of the capital investment does enter the rate base when the regulatory commission decides, implicitly or explicitly, that it meets the relevant criteria, such as "used and useful" or "prudent." This treatment of extensions allows the utility to put the depreciation expense and return on investment for that asset into rates, typically (but not always) in a rate case.

Investors then anticipate, based on an assessment of regulatory risk, that their investment will be paid off in full over the lifetime of the asset. Significant economic and policy shifts can change the expectations around these capital investments, and this risk is built into pricing returns on utility investments. When those circumstances result in an asset that is no longer of significant use to the system but is not yet

90 Although this terminology is complex, it can be analogized to a more typical loan or mortgage for everyday consumers. The depreciation expense is akin to the portion of a loan payment that goes to the principal, and the return on investment is the portion that goes into interest.

91 Maintenance expenses for capital assets can vary randomly and sometimes be deferred but never indefinitely unless a particular asset is no longer in service.

92 In part because of this terminology, depreciation expense is often categorized with other expenses, although that may be misleading for some purposes.

93 For more on this subject, see Lazar, J. (2016). *Electricity regulation in the US: A guide* (2nd ed.). Regulatory Assistance Project. <https://www.raponline.org/knowledge-center/electricity-regulation-in-the-us-a-guide-2/>

fully depreciated, the assets can become stranded. An early retirement of a portion of the current gas system would almost certainly result in stranded assets, as discussed in previous sections. The stranded costs of that portion of the gas system are typically defined as the remaining book value of those assets, which is in turn defined as the original cost minus the accumulated depreciation of the assets over the years that the assets were in rate base. An asset need not be fully stranded to have an impact on ratepayers. As long as the capital payment for an asset or set of assets remains a part of the revenue requirement, it influences rates. If gas throughput goes down substantially, then mathematically either volumetric rates must go up or the remaining capital payment for those assets must be put in a different rate (e.g., customer charges).

Many different steps can be taken to lower rate base, thus mitigating long-term rate increases on gas customers who remain on the system in the coming decades and lowering the risk of stranded costs. For new investments, updated planning frameworks and improved programs, as discussed in the previous sections, can lower the total new investments made by a gas utility. If the level of new investment declines sufficiently, total rate base should start to trend downward. In addition, for any new gas system expansions, a utility can require additional contributions from new customers to lower the risk of future rate increases and stranded costs. Existing investments cannot be changed, but the remaining portion of those investments that is still in rate base represents a risk of future ratepayer impacts and stranded costs. Accelerating the timeline for depreciation is another significant option to pay off the costs of either existing or new investments more quickly. Taken collectively, these methods of lowering rate base should improve flexibility for regulators in coming decades and minimize rate impacts on future customers, as well as any need to seek alternative sources of funding.⁹⁴

Increase Customer Contributions to Line Extensions

One method that regulators can use to lower rate base, and thus mitigate rate impacts in coming decades, is to increase required payments for customers requesting new connections. These required payments should be calculated based on updated projections of expected customer gas usage and the likelihood of customer conversion away from gas, either partial or full, in the future.

As briefly discussed in Section III, every jurisdiction has rules for gas utilities that dictate the circumstances under which gas mains can be extended to provide service to new streets, new neighborhoods or new towns and a new customer can be added to an existing gas main. These rules provide a variety of terms and conditions that new customers must obey and limits on the amount of money that a gas utility can justify investing in new infrastructure.

These limits may often be rules of thumb but are generally dictated by the amount of gas that a utility can expect to sell to a new customer or set of customers.⁹⁵ Based on the new sales, the gas utility expects these new customers to contribute sufficiently to pay off a certain amount of new capital investment. By ensuring that new customers contribute to capital expenditures, the utility avoids unreasonable cross-subsidies from existing customers to new customers.

Extending the relevant gas infrastructure is typically allowed if it costs more than the relevant limits, as long as the potential new customers are willing to cover the remainder of the costs upfront. The simplest version of such a policy, aptly known as a contribution in aid of construction (CIAC), requires a new customer to pay for a portion of the line extension. The customer contribution to the infrastructure investment is deducted from the gas utility's rate base. CIAC policies have two important impacts. First, CIAC payments are an important cost allocation tool as they determine the cost split between the new and existing customers. Second, the size of CIAC payments can dictate whether potential customers

94 Securitization (discussed in the text box on Page 16) can remove a portion of rate base and convert it into low-interest debt guaranteed by ratepayers or potentially the government.

95 For some utilities, initial service contracts include minimum annual or average annual consumption requirements, which are another way of guaranteeing that a new customer is paying for the incremental costs and satisfying at least part of the assumptions behind the line extension policy parameters — if such a provision can be enforced.

ultimately choose to become gas utility customers at all.

A more complex version can take place when gas service is being introduced in a new area, where there are many potential customers but only one (or a small number) is connected initially. In such a scenario, the first customer in a new area may pay for the full cost of a system expansion but would receive a refund if and when additional customers connect to the system in that geographic area. This approach is called a customer advance and is also treated as a rate base reduction. As new customers join the system, the first customer gets a portion of their system prepayment back.⁹⁶ When such a policy applies, the first customer may be taking on a significant risk, betting that a sufficient number of other customers will connect to the system.⁹⁷

Yet another approach is a new customer rate surcharge for a certain number of years to cover the excess investment cost. Such an approach enables any new customers to avoid an upfront payment but also assumes that these customers will use sufficient gas for a long enough time to pay back those costs. These policies may come with contract commitments to that effect for those customers, which could lock in more gas consumption than otherwise necessary.

Given changing circumstances, there are two related issues that regulators may want to require gas utilities to reflect in updated calculations: (1) lower assumed gas usage and (2) a shorter assumed lifetime. Efficient gas appliances, improved building shells and the chances of conversion away from gas for one or more end uses all lower expected gas usage, and the probability that each customer will leave the gas system entirely is increasing with possibilities for electrification. Regulators considering these new realities may want utilities to consider higher CIAC payments and customer advances, as

well as the increased risk for customers who do give advances. Overall, such changes would likely result in somewhat fewer customers added to the gas system in the short term and additional customer contributions from those who are added. Such an outcome would result in constrained growth of the gas network, a lower rate base and lower potential rate impacts and stranded costs in coming decades.

Accelerate Depreciation Timelines

A second method regulators can use to lower rate base is to accelerate depreciation timelines. Accelerated depreciation timelines, for both previous and new investments, in the short term can greatly decrease the amount of remaining rate base in coming decades. In so doing, regulators can effectively allow for a modest rate increase today, over a large base of customers and usage, in exchange for lower rates in the future, when both the customer base and usage will likely be shrinking.

Many gas system capital investments are assumed to have extremely long asset lives, often 60 to 80 years for gas mains.⁹⁸ In other words, mains installed in the year 2000 are expected to be operational until at least 2060 and mains installed in 2020 to be operational until 2080 or 2100. These dates can be easily juxtaposed with GHG reduction policies that will require major reductions in the combustion of fossil gas between 2030 and 2050. The formulas used to recover these costs assume that the depreciation expense and return on investment can be recovered over the entire assumed life of the asset. The revenue requirement for any given year thus facilitates the recovery of a fraction of the cost of the asset.

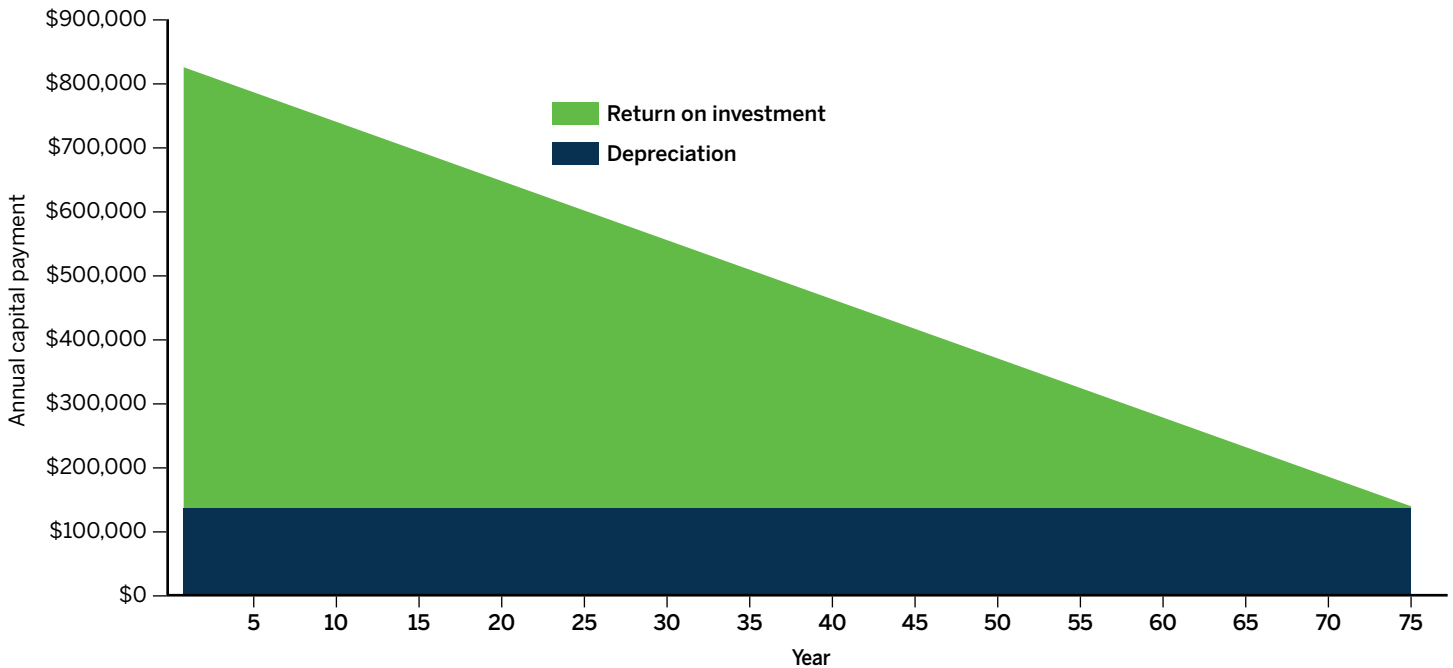
This treatment is considered fair because all customers that use the asset over its lifetime will be paying for it, although current methods do typically frontload this cost

96 Some or all of that refunded advance may be contributed upfront by the additional new customers, or else the incremental consumption from those customers is estimated to cover that portion of the capital costs over time. In those two situations, the rate base ends up being slightly different. If the refunded advance is paid on a one-to-one basis by the additional new customer, utility rate base stays the same. But otherwise, utility rate base would increase.

97 In another variation, a whole group of customers (or a developer) is required to pay a customer advance to justify initial utility investment and risks. When the investment is completed and services are connected, the advances would be immediately refunded to the customers or the developer.

98 Southern California Gas Co. assumes 64 years for transmission mains and 68 years for distribution mains. Southern California Gas Co. (2017). *Revised*

SoCalGas direct testimony of Flora Ngai (depreciation). Before the Public Utilities Commission of the State of California, A.17-10-008, SCG-36-R. <https://www.socalgas.com/regulatory/documents/a-17-10-008/SCG-36-R%20Ngai%20Revised%20Direct%20Testimony.pdf>. Xcel Energy's Colorado subsidiary assumes 72 years for transmission mains, 72 years for metallic distribution mains and 68 years for plastic distribution mains. Alliance Consulting Group. (2016, September 30). *Public Service Company of Colorado gas technical depreciation update*. <https://www.xcelenergy.com/staticfiles/xcel-responsive/Company/Rates%20%20Regulations/Rate%20Cases/Attachment-MLO-7.pdf>. ConEd uses 70 years for cast iron mains, 90 years for tunnel mains and 85 years for all other mains. New York State Department of Public Service Case Nos. 19-G-0065 and 19-G-0066. Joint proposal, October 16, 2019, Appendix 11, p. 3. <http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=19-G-0066&CaseSearch=Search>

Figure 12. Illustrative depreciation expense and return on \$10 million investment

recovery toward the beginning of the asset's life because the typical practice in utility rate-making is to use straight line depreciation. Using this method, if an asset is worth its original cost in its first year in service and zero at the end of its useful life, annual depreciation expense is equal to the original cost divided by the number of years in the amortization period. Given that assumption, the payments for return on investment are relatively high at the beginning and decline linearly over time as the rate base is being paid down through the annual depreciation expense. Figure 12 illustrates typical trajectories for the annual depreciation expense and return on investment for a \$10 million investment that is amortized over 75 years at a 7% weighted average cost of capital.

In the modern world, where the gas system may need to change or shrink significantly, the physical capabilities of an asset like a gas main are no longer the only limitation to be considered. Obsolescence, due to technology, policy changes or changes in demand, is another typical factor in determining

an asset's life for depreciation of a capital investment.⁹⁹ As a result, assumed lives for existing and new gas system assets may need to become significantly shorter for the purposes of depreciation. With straight line depreciation, there is a straightforward relationship between the amortization period and the depreciation expense. If the amortization period is cut in half, then the depreciation expense doubles.

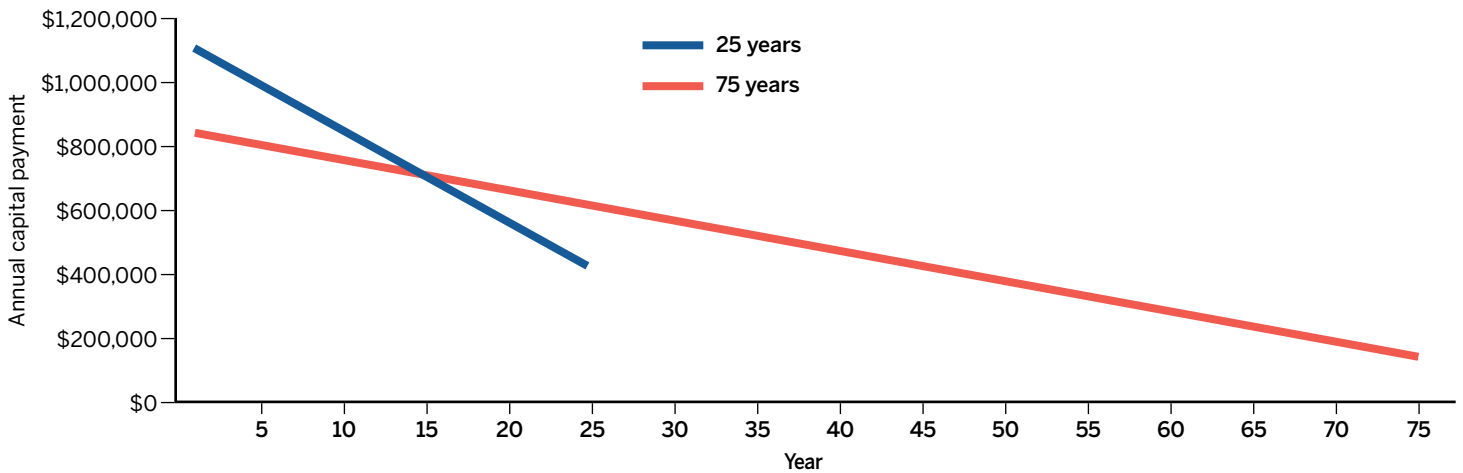
The change in depreciation expense is not the only change in the revenue requirement that takes place when the amortization period changes. The return on investment is based on net plant in service, which is defined as the gross original cost minus the accumulated depreciation.¹⁰⁰ As depreciation accumulates more quickly, the net plant in service goes down more quickly, reducing the amount of return on capital paid by ratepayers. This result is similar to a homeowner making an extra mortgage payment every year, which causes an additional upfront expense but can dramatically reduce the interest payments made over time and the debt duration.

99 The FERC Uniform System of Accounts for gas companies defines depreciation as "the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public

authorities, and, in the case of natural gas companies, the exhaustion of natural resources." Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act, 18 C.F.R. § 201, Definition 12.B.

100 This assumes zero net salvage costs, as do the quantitative examples in this section.

Figure 13. Illustrative trajectory of capital payments for two amortization periods



Considering the total capital payment (both depreciation expense and return on investment) collectively reveals a more complete picture. Figure 13 shows two different repayment trajectories, 75 years and 25 years, for a \$10 million capital investment at a 7% weighted average cost of capital. Shareholders should be equally well off with either of these payment trajectories.

Even though the depreciation expense is three times higher with a 25-year amortization period, the overall capital payment is only 32% higher in the first year. This gap between 25-year and 75-year capital payments shrinks steadily over time, and the overall capital payment is lower starting in

year 16 for the shorter amortization period.

Many capital investments in rate base, particularly long-lasting assets, are not new and have already been partially depreciated. Take, for example, a gas main put into service at the beginning of 1986 with an asset life of 75 years, meaning it would be fully depreciated and paid off in 2060. This asset has already been depreciating for 35 years and, at the end of 2020, has 40 years left on its expected life. This asset's expected remaining life could be shrunk to 25 years, meaning an expected retirement in 2045. Figure 14 shows this scenario, again for a \$10 million capital investment at a 7% weighted average cost of capital.

Figure 14. Illustrative capital payments with change in amortization period for partly depreciated asset

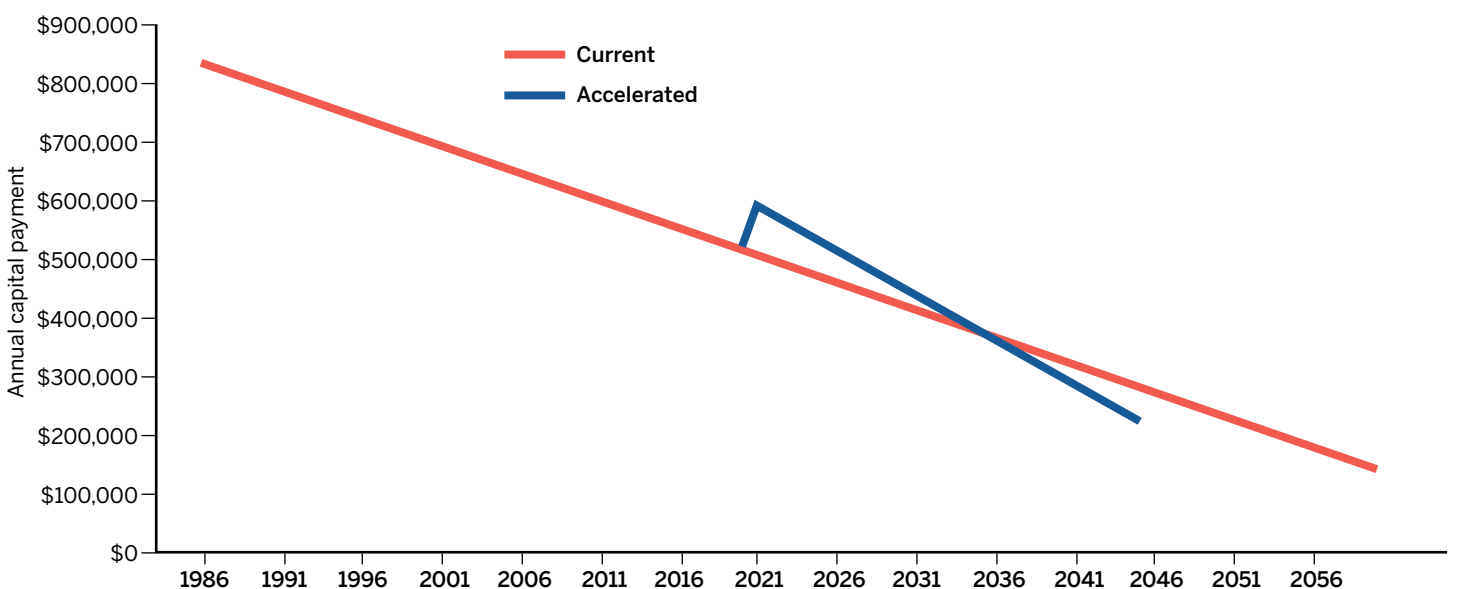
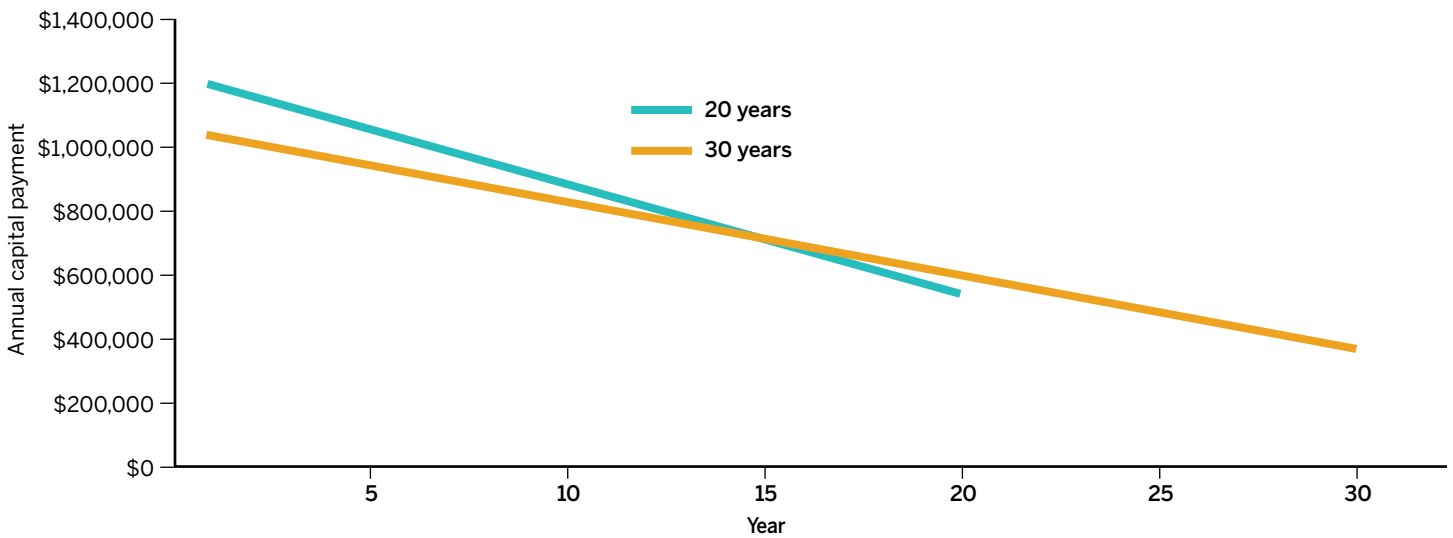


Figure 15. Illustrative capital payments for two amortization periods



This change results in a capital payment that is 17% higher in 2021 for this asset. Once again, however, the gap shrinks quickly, and ratepayer costs are lower starting in 2036 with the shorter amortization period.

Not all of the changes to capital amortization periods would need to be so substantial. Some shorter amortization periods may not need to change at all. Some assets with amortization periods of 20 to 40 years could be decreased to 15 to 30 years. Figure 15 shows different repayment trajectories, 30 years and 20 years, for a \$10 million capital investment at a 7% weighted average cost of capital.

Even though the depreciation expense is 50% higher with the 20-year amortization period, the overall capital payment is only 16% higher in the first year, and the gap shrinks over time in future rate cases.

When implemented in a rate case, changes to depreciation rates and amortization periods will reflect a mix of these different circumstances. A simplified illustrative scenario provides

some intuition about how this may work in the real world.

Table 1 shows four categories of illustrative capital investments.

Table 2 on the next page shows the difference in the capital payment for each category of capital investments, as well as the total. In this illustrative example, a significant acceleration of depreciation leads to a 19% increase in the capital payment in the first year (2021).

Such changes to the amortization period only affect a portion of the rate, meaning that the overall impact will be a significantly lower percentage. If the capital payment for the gas LDC represents only a third of overall annual gas bills, with the other two-thirds primarily represented by gas supply costs, delivery O&M costs and taxes, then the overall bill impact would be only an approximately 6% increase.

Other related changes would likely occur to the revenue requirement as a result of accelerated depreciation. The above illustrative analysis does not include any changes to the timing of net salvage costs. In some jurisdictions, gas pipe

Table 1. Illustrative capital investments undergoing accelerated depreciation

	In-service year	Original cost	2021 remaining book value	Amortization		
				Original end date	New end date	Change in length
Recently added long-term assets	2016	\$300,000,000	\$280,000,000	2090	2045	45 years
Older long-term assets	1986	\$500,000,000	\$266,666,667	2060	2045	15 years
Medium-term assets	2011	\$200,000,000	\$150,000,000	2050	2040	10 years
Short-term assets	2016	\$100,000,000	\$75,000,000	2035	2035	None

Table 2. Effect of accelerated depreciation on capital payment in first year

	Status quo capital payment	Accelerated depreciation capital payment	Percent change
Recently added long-term assets	\$23,600,000	\$30,800,000	31%
Older long-term assets	\$25,333,333	\$29,600,000	17%
Medium-term assets	\$15,500,000	\$18,000,000	16%
Short-term assets	\$10,250,000	\$10,250,000	0%
Total	\$74,683,333	\$88,650,000	19%

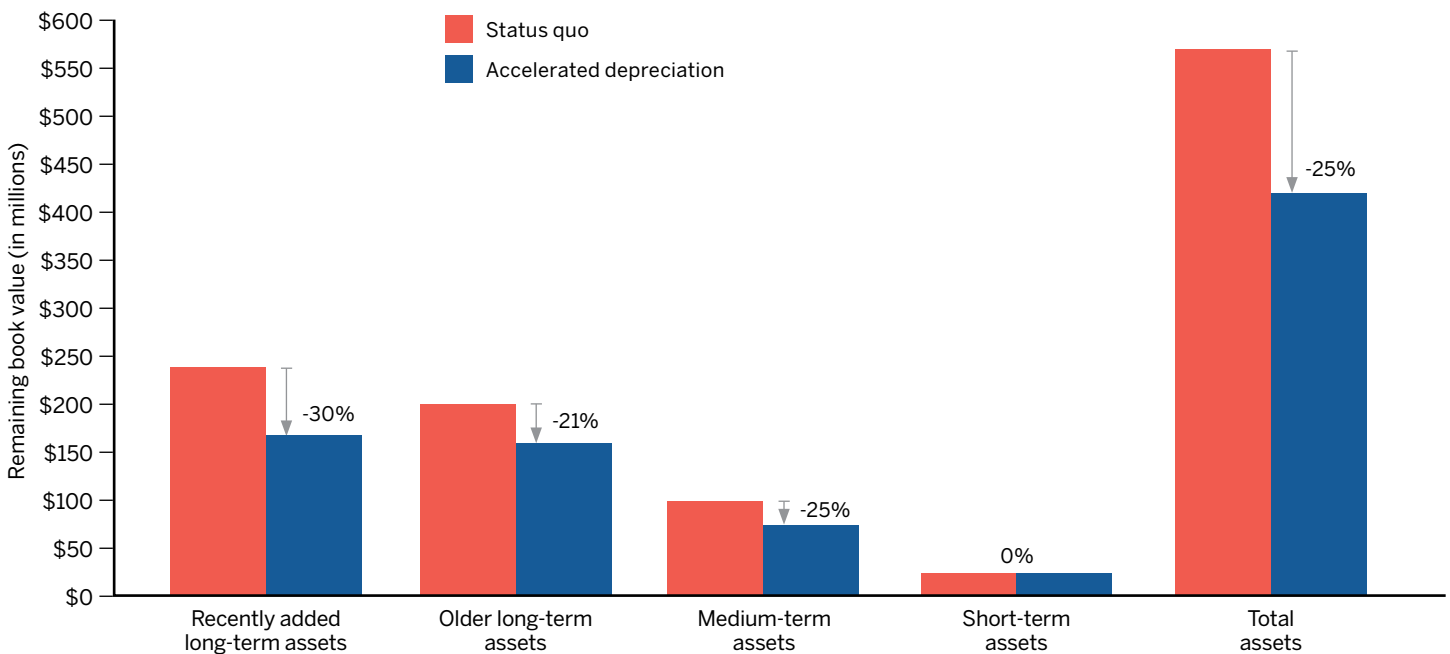
is abandoned in place, which means minimal salvage costs, although other governments may require removal for safety purposes. For any gas mains that are removed, the expense can be significant because of costs incurred digging up and removing the pipe and restoring the surface to its original condition. To the extent that removal is required sooner, those costs will have a higher net present value.

In the other direction, accelerated recovery of capital

assets should lower the uncertainty of capital recovery — thus lowering the risk that needs to be incorporated into the return on equity or allowing for a higher debt-to-equity ratio in the capital structure, either of which would lower the revenue requirement.¹⁰¹

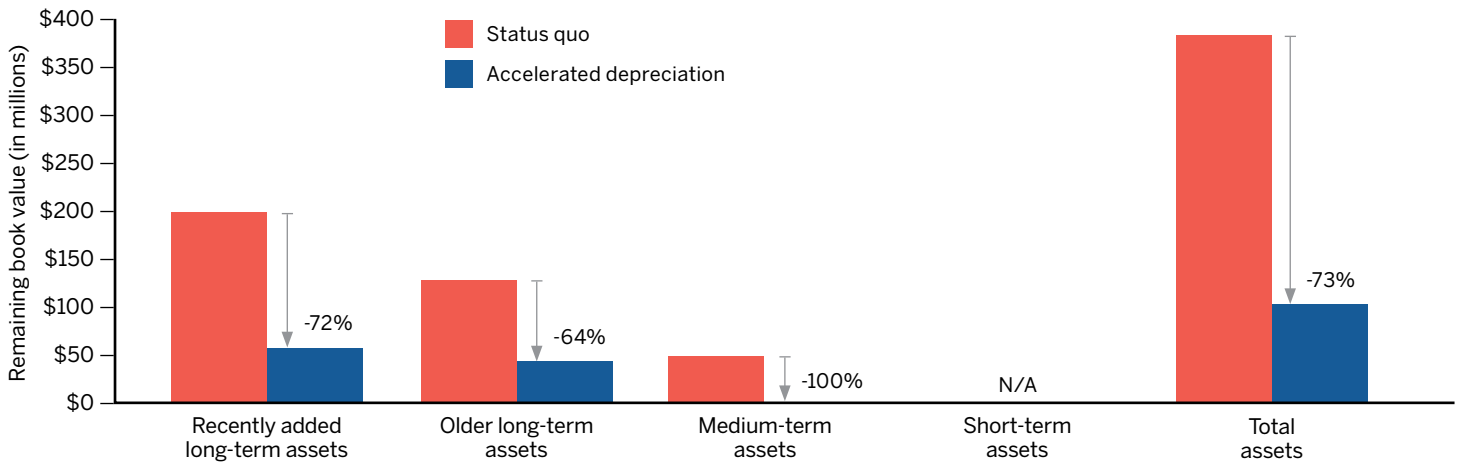
Using the illustrative scenario in Table 1, Figure 16 shows the remaining book value, one measure of potential stranded costs, in 2031 under accelerated depreciation. Although the

Figure 16. 2031 remaining book value for pre-2021 investments under two depreciation scenarios



101 Another complexity is a reduction in accumulated deferred income taxes over time for some utilities. In some jurisdictions, where the taxes included in rates are exactly those paid by the utilities, this consideration is not of concern. Many utilities take advantage of the tax code with accelerated tax depreciation, however, which allows deferral of income taxes — effectively a zero-interest loan from the government. These utilities then use longer depreciation timelines for defining the depreciation expense in the revenue requirement. This income tax deferral is accounted for in rates either as a reduction in the rate base or as zero cost capital for inclusion

in the weighted average cost of capital. Depending on the technique used, accelerated depreciation for rate-making purposes would be represented as either a partially countervailing increase in rate base or a reduction in zero cost capital. In either case, tax deferral, and its impact on rates, is a factor that should be analyzed for specific proposed changes for each utility. As an administrative matter, it would be quite simple if the accelerated tax depreciation rates for new investments were used as the book depreciation rates for rate-making.

Figure 17. 2041 remaining book value for pre-2021 investments under two depreciation scenarios

decrease in remaining book value varies by category, the overall reduction in remaining book value is 25%, approximately \$140 million.

Figure 17 shows the same scenario in 2041.

By 2041, 20 years of accelerated depreciation has a major impact on remaining book value, a reduction of 73%, or around \$280 million. By 2050, all these assets have been completely paid off in the accelerated depreciation scenario, but under status quo depreciation policies, there would still be \$240 million in potential stranded costs for these assets. If shareholders do not bear these costs, or another source of funding is not found, remaining ratepayers must bear them. If the number of remaining customers and sales have shrunk significantly, rates increase significantly because those costs are spread over lower billing determinants.

The major benefit of an accelerated depreciation approach would be to greatly lower the potential stranded costs for existing assets and risks of rate increases to remaining ratepayers from declining throughput and thus to increase regulatory flexibility over time. Existing assets can be paid off at a much faster rate, so the primary risk lies with new investments. Accelerated depreciation would also raise the bill impacts of new investments, although those investments can also be addressed through a reformed planning process and improved

programs as discussed earlier in this paper. Each jurisdiction, and potentially every utility, likely will need to analyze these issues in detail, since the existing regulatory requirements and the mix of capital assets involved will differ.

B. Adopt Efficient and Equitable Rate Structures

Rate structure encompasses two parts of the rate-making process: cost allocation and rate design. Collectively, these two steps determine how costs are shared across all gas utility customers and provide the prices that shape customer behavior over time. At a high level, improved cost allocation can ensure equitable contributions across customer classes, while rate design can help lower the need for new system capacity investments, equitably split costs within customer classes, and be a part of efficient customer incentives to switch from gas to cleaner alternatives. RAP has written extensively about cost allocation and rate design, primarily in the context of electric utilities.¹⁰² The principles for gas utilities are largely the same, but there are important differences in the engineering features of the gas system as well as the underlying structure of customer demand.

Reforms to cost allocation and rate design can help enable

102 See Lazar, J., Chernick, P., Marcus, B., & LeBel, M. (Ed.). (2020). *Electric cost allocation for a new era: A manual*. Regulatory Assistance Project. <https://www.raonline.org/knowledge-center/electric-cost-allocation-new-era/>; and Lazar, J., & Gonzalez, W. (2015). *Smart rate design for a smart future*. Regulatory Assistance Project. <https://www.raonline.org/knowledge-center/smart-rate-design-for-a-smart-future/>. In addition, cost

allocation is discussed at some length in NARUC Staff Subcommittee on Gas. (1989). *Gas distribution rate design manual*. National Association of Regulatory Utility Commissioners. <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B04381803-1D3A-4CD7-BBE3-64EDB16835C0%7D>

a gas transition in several ways. Existing cost allocation and rate design practices may already be leading to inequitable contributions to system costs and inefficient customer incentives. Reforming these techniques can remedy inequities in our current system. In addition, modern analytical techniques provide a range of more flexible and accurate tools that can affirmatively reduce system costs going forward and be accurately updated over time as the gas system and customer usage patterns change.

One important principle is that a substantial portion of system costs are driven by peak customer demand. For the gas system, peak is largely defined by the highest demand days, unlike the electric system, where it is typically defined by the highest demand hours. This difference is in part because more gas can be stored near customers on the gas distribution system, such as through linepack, wherein gas molecules are stored in the pipeline under high pressure, enabling it to contain a high volume of gas. With storage, the gas system does not need to react as quickly to changes in consumption as the electric system does. Conversely, in some ways the gas system cannot react as quickly as the electric system. In contrast to voltage and frequency changes, which are more or less instantaneous, the gas system's response to changes in consumption requires having the necessary supplies in the right locations. Taking full advantage of the gas system's attributes thus requires planning and efficient advance storage of gas in locations where it may be needed.

Many gas end uses are year-round, such as water heating, cooking and drying clothes; collectively these end uses have a high annual load factor. These uses are cheaper to serve per unit of consumption. In the winter season, significant additional heating demand is added on top of base usage. This winter heating usage has a lower annual load factor and is more expensive per unit of consumption.

The peak day or days for a gas utility typically come amid longer stretches of cold weather. Improved building shells can help retain heat and lower the need for lengthy peak consumption periods for individual customers, but these improvements do not necessarily change the basic pattern. In conjunction with the storage features of the gas system, load patterns dictate the much longer peak windows for the gas system.

Extremely cold days require provision of adequate gas supply, often from storage or liquified natural gas, and adequate distribution capacity, even though this capacity is needed only a few days of the year. This extreme weather usage is the most expensive to serve per unit of consumption.

In the broadest sense, the economic efficiency of a rate structure is reflected in customer responses to prices. As a result, regulators might want a system where customers' response to reduce their own bills is the same response that would minimize system costs. In this context, usage-based pricing provides an incentive to lower consumption, and time-varying pricing (to the extent that it is feasible) is an incentive to lower usage in particular time periods. In contrast, customer charges, fixed monthly fees that cannot be avoided without disconnecting from the system, provide a different incentive. To the extent that customers can adopt end uses that do not rely on delivered gas, higher customer charges encourage existing customers to disconnect or prospective new customers not to connect at all, especially if their usage levels are or would be low.

While equity in the allocation of costs is a core principle for both cost allocation (among rate classes) and rate design (within rate classes), bill impacts on LMI gas customers are a key dimension of equity as well. Regulators may want to avoid substantially adverse impacts on any LMI customers who cannot affordably convert to a zero-carbon alternative or even propane as a transition measure.

Cost Allocation Between Rate Classes

Many of the general principles for cost allocation are shared by both gas and electric utilities, so high-level recommendations are relatively similar. Good data collection forms the basis of good cost allocation practices, including customer usage data (either for all customers or sampled) and detailed cost data. Customers are sorted into classes ideally meant to distinguish them based on separate cost characteristics, which can be fairly translated into different rate structures and levels. In practice, customer classes often primarily reflect distinctions that are easily administered, such as residential versus commercial. Some customer class distinctions may be made based on the gas uses on-site,

such as a residential heating customer class.

In addition, some customer classes may reflect special customer characteristics, agreements or rate structures. For example, a customer class could be defined by interruptible service, where customers agree that their gas service can be shut off to provide for broader system needs. Customers on interruptible service typically have alternative fuel sources for the relevant end uses or are able to curtail their activities, so they are less reliant on gas delivered by pipe at any moment in time. In exchange for the agreement to be interrupted, these customers get lower rates because they are allocated fewer capacity costs, which reflects the fact that they get cut off at system peak times and thus do not drive peak costs. They do, however, use system capacity and are generally required to make a significant contribution to system costs over the course of a year.

In the traditional cost allocation process, the costs in the revenue requirement are functionalized and classified in separate analytic steps before final allocations are made to each customer class. The recommendations that follow lead to a fairer split of costs among classes than older methods and can also be used to underpin more efficient rate designs that properly reflect cost causation, thus leading to more efficient customer incentives.

We recommend the following:

- Customer-related costs should be determined using the basic customer method, where only the individual cost of connection (e.g., the service line and final regulator), billing and certain customer service expenses should be allocated on a per-customer basis. Furthermore, many of these costs will be more expensive for larger customers, so special cost studies can be warranted to determine the proper differentials.
- Shared capacity costs (transmission, distribution and storage) should be split between energy-related costs and peak-related costs, using the average-and-peak method — where the system load factor defines the percentage of shared capacity costs that is allocated on the basis of energy throughput, and the remainder is allocated based on a metric of peak demand — or more sophisticated time-based methods.

- Fuel commodity costs should be allocated based on time-based energy throughput methods. As a practical matter, the relevant cost causation basis for customers receiving gas supply from the local distribution company is the procurement process, which is often seasonal and reflects differences in costs across the procurement periods.
- Administrative and general costs should be apportioned across usage metrics based on revenue, or across all allocation metrics based on revenue.
- Program costs, such as efficiency and beneficial electrification programs, can be allocated based on the benefits provided by the investments. For example, the program costs that result in reduced needs for capacity investments can be allocated in proportion to the system benefits that accrue to each class. Program costs can also be allocated based on program participation. The costs of beneficial electrification programs can be fairly divided between gas and electric utility customers within a jurisdiction, since both sets of customers typically benefit. Such allocation is most easily administered if gas and electric service territories are strongly overlapping or if these programs are run by statewide third-party entities.

Many utilities and some analysts prefer to use either the minimum system or zero intercept methods, which include a substantial part of shared distribution capacity costs, to estimate customer-related costs. These methods overstate customer-related costs, however, because they do not properly reflect the costs of adding an additional customer. Adding one more customer on an existing main only incurs minimal costs for the connection to the customer and billing, which is calculated properly using the basic customer method. The decision to build the distribution system, guided by the line extension policy, is largely driven by expected sales, not by the number of customers or customers' willingness to shoulder additional costs themselves.

Once it is understood that each industrial customer drives significantly more shared system capacity costs than an individual residential customer, it is easy to see that the number of customers is not the key driver of system costs. Instead, the key drivers of shared delivery system costs are the overall patterns of usage across all customers and the geographic dispersion

of those customers. Cost differentials due to differing usage patterns of individual customers can be reflected in both cost allocation and pricing, to the extent metering and billing systems allow. Locational distinctions often cannot be reflected in rates because of the convention of postage stamp pricing, where the utility offers one rate to all customers in a class without any geographic distinctions.¹⁰³

In some jurisdictions, many costs, particularly shared capacity costs, are apportioned nearly entirely on the basis of the peak day demand. As a result, costs are heavily allocated toward customer classes with large winter heating usage, such as residential customers. Instead, as a substantial portion of capacity costs are incurred to provide year-round service, only the additional cost of upsizing capacity and certain storage facilities for peak demand should be allocated specifically to peak times. This reality dictates that time-based allocation methods are superior to methods that rely entirely on either peak demand or annual consumption. One simple time-based method is the aforementioned average-and-peak.¹⁰⁴ When applying this method, a strongly seasonal demand shape, with a lower overall system load factor, results in more costs allocated based on the peak. Sophisticated versions of time-based allocation methods are feasible with more complete load data enabled by improved metering where it is available, better system cost data and improved analytical tools. These methods better reflect cost causation, lead to fairer results and enable more efficient time-varying rate designs.

Bill impacts for different categories of customer can be considered in either the definitions of customer classes or various methods for allocating costs among classes. In some service territories, industrial customers are able to choose between gas service from the LDC or directly from the federally regulated transmission system. As a result, methods that increase cost allocations to industrial customers may not yield

their intended results because those customers could bypass the LDC instead.

In addition, bill impacts to LMI residential customers, particularly those who use gas heating and cannot affordably switch to another fuel, should be examined closely. Customers can be shielded from undue burdens in several ways, such as dedicated rate classes for either residential heating customers or LMI customers. Rate design, which we will discuss next, is another tool that can be used.¹⁰⁵

Rate Design

Each customer class has its own rate design and sometimes one or more subclasses with different rate designs. Within a customer class, sometimes one or more rates can be optional as well. The key is to move customers toward more efficient overall pricing structures while satisfying the related principles of customer understanding and fair bill impacts. There is an intertwined relationship among those three principles: Customers can respond to efficient prices only if they understand them, and a lack of understanding of new pricing structures can lead to unfair and unexpected bill impacts. Meeting these pricing principles should lead to more efficient customer behavior, thus helping to lower system costs and preventing unfair and inequitable bill impacts over the course of the transition.

As a result, regulators can take into account different levels of sophistication among customer types and offer bill protections of various kinds to less sophisticated customers. Gradualism in this respect can be crucial, with new kinds of rates introduced in a deliberate manner over a period of several years or over multiple rate cases, and customer education and outreach programs are also key. Larger commercial and industrial customers often have dedicated energy managers or can afford energy management technology to control the

103 Line extension policy often does dictate cost differentials based on location, of course, and there are other exceptions to this general rule.

104 See NARUC Staff Subcommittee on Gas, 1989, pp. 27-28. Many different jurisdictions use average-and-peak for allocation of distribution capacity costs. For example, regulators affirmed its use in a natural gas rate case for Consumers Energy Co. See Michigan Public Service Commission, Case No. U-18124, Order on July 31, 2017, pp. 113-14. <https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000001UUAgAAO>.

As of 2016, 20 states used either basic customer or the average-and-peak method, according to Minnesota regulators. See Minnesota Public Utilities Commission, Docket No. G-008/GR-15-424, Order on June 3, 2016, pp. 53-54. <https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPop&documentId={92AB0946-4F77-4A70-BF38-7D36F88AC979}&documentTitle=20166-121975-01>

105 Rate or bill discounts for LMI customers may not be allowed in all jurisdictions without statutory amendments.

usage of different end uses over time. Small customers cannot afford to pay dedicated staff, and many energy management technologies are cost-prohibitive as well, although this will likely change over time.

A key objective should be improved seasonal and monthly pricing variation for all customers, while keeping in mind that high-cost periods driven by system peaks are often the times of greatest usage for residential heating customers. This is simple enough for every jurisdiction and practically all types of customers.

Regulators should require increasingly granular pricing for sophisticated customers as allowed by utility metering and billing systems. Currently, larger businesses are most likely to fall into this category, but more granular pricing could be extended to smaller businesses and larger residential customers over time. Regulators can consider a number of options for more granular pricing for the highest demand days:

- Demand response programs.
- Critical peak pricing.
- Direct load control.
- Interruptible rates.

These options are interrelated. Direct load control, such as via smart thermostats, gives the gas utility the option to turn off or turn down individual end uses, whereas an interruptible rate gives the utility that option for all of the customer's usage. Similarly, a demand response program may only apply to one end use for a customer, whereas critical peak pricing applies to all customer usage when the system is under severe stress.

As above with cost allocation, a regulator should pay attention to the possibility that large customers will bypass the LDC to get service at the interstate transmission pipeline level. Relatedly, it could be an issue in some jurisdictions that the customer response to high peak gas pricing would be additional reliance on electricity from the grid. For example, a combined heat and power gas customer could reduce or stop its electricity generation in favor of taking electricity from the grid. In some jurisdictions, electricity rate designs (e.g., traditional demand charges) may discourage this type of short-term reliance on the electric system, and there may be tensions

between electric system needs and gas system needs.

Fair and efficient pricing for less sophisticated customers, particularly those who rely on gas for heating service, should almost certainly have a simpler structure. The major tension is that charging higher rates at times of system stress almost invariably would fall at times that heating demand is the highest — meaning long stretches of winter cold weather. Doing so would likely cause higher bills for customers who cannot afford to weatherize their homes or could tempt people on fixed incomes to keep the heat so low that it risks their health. Of course, improved energy efficiency and electrification programs can significantly ameliorate this impact, particularly if those programs are well designed for low-income and vulnerable populations. Rates for these customers should still have seasonal and monthly variations and could potentially have simpler time-based structures to shape residential gas demand, as well as peak-time rebates or direct thermostat controls. More sophisticated rates could be offered to these customers as an option, with, potentially, additional customer protections, such as a one-year hold-harmless provision after adoption.

Another measure to address related efficiency and equity concerns could be an inclining block structure, where the initial block of low-cost gas in the winter could be sized to cover the space heating needs for a moderately sized residence of average efficiency. A higher-priced tail block would still retain good efficiency incentives for larger and less efficient homes, as well as homes with gas usage beyond space heating. Regulators could build off this concept in different directions. A particular rate could be made available to a limited subset of residential customers, such as LMI customers or LMI gas space heating customers.

The rates charged by the Palo Alto municipal gas utility in California are an example of this type of design (see Table 3 on the next page).¹⁰⁶ For volumetric distribution pricing, there is a summer seven-month seasonal period with a modest initial block of 20 therms at a relatively low distribution price and a more expensive tail block rate. In the winter months, the initial block at a low price is much larger

106 City of Palo Alto. (n.d.). *Residential gas service: Utility rate schedule G-1*. <https://www.cityofpaloalto.org/Departments/Utilities/Customer-Service/Utilities-Rates/Residential-Rates>

Table 3. Residential distribution rates for municipal gas utility in Palo Alto, California

	Summer (April 1 to Oct. 31)	Winter (Nov. 1 to March 31)
First 20 therms	\$0.5038 per therm	N/A
First 60 therms	N/A	\$0.5038 per therm
Additional usage	\$1.288 per therm	\$1.288 per therm

Source: City of Palo Alto. (n.d.). *Residential Gas Service: Utility Rate Schedule G-1*

at 60 therms, with the same higher tail block price. Supply charges vary monthly based on market prices, with no tiering.

Last, discounts for LMI customers can be applied to the otherwise applicable rate designs, although such an approach may not be allowed in certain states. In other states, however, discounted or eliminated customer charges or percentage reductions based on the bill total are methods to ensure that LMI customers are not unduly affected by changed rate designs.

C. Change Utility Incentives

Another consistent feature of traditional cost of service regulation is the incentives provided to a utility and particularly the ways that management is able to increase shareholder value. In advance of a rate case, utility management can maximize shareholder value by adding more prudent capital investments, the explicit source of profit in the revenue requirement calculation. This is known as the Averch-Johnson effect.¹⁰⁷ Separately, there are two primary ways that utilities can earn additional net revenue between rate cases: increasing sales and cutting costs. In a situation where expansion of utility service is unambiguously socially desirable and there is little concern over external costs of production or consumption, this set of utility incentives can be workable, as with the expansion of electricity service in the 20th century.

These assumptions no longer describe the circumstances

of modern gas or electric utilities. This drive for continued capital expansion is fundamentally at odds with the coming trends that will impact gas distribution companies, as well as needed reforms to planning and programs. The incentive for increased gas sales or to add new customers is similarly problematic. Regulators should take steps to rein these incentives in. Over the past 40 years, numerous jurisdictions have changed significant elements of the traditional utility business model, particularly through (1) revenue regulation, also known as decoupling, and (2) broader reforms collectively referred to as performance-based regulation.

Adopt Decoupling Using Overall Revenue Target, Not Revenue Per Customer

In traditional rate-making, utility regulators are establishing rates for the utility, and the calculated revenue requirement is only an intermediate product that has little relevance going forward. The actual revenue the utility earns after the rate case is the rates multiplied by actual billing determinants. For gas utilities, the relevant billing determinants are primarily the number of customers and the amount of gas sold. Gas utility revenue could be higher or lower than the revenue requirement, depending on the evolution of actual sales between rate cases.¹⁰⁸ This provides a substantial incentive for utilities to increase profits by increasing sales. Revenue regulation, also known as decoupling, diminishes this incentive by turning the revenue requirement into a revenue target, which can be subject to many different types of adjustments over time. The intention of all types of decoupling is to dampen the link between a utility's earnings and profits and its overall sales levels, thus lowering a barrier to energy efficiency improvements. This reform can be a boon to efforts to slow gas sales growth or begin to shrink overall usage.

There are many varieties of decoupling, and they can create subtly different incentives for utility behavior. One common method for gas utility decoupling is known as the

107 Averch, H., & Johnson, L. T. (1962). Behavior of the firm under regulatory constraint. *American Economic Review*, 52(5), 1052-1069.

108 See Lazar, J., Weston, F., Shirley, W., Migden-Ostrander, J., Lamont, D., & Watson, E. (2016). *Revenue regulation and decoupling: A guide to theory and application (incl. case studies)*. Regulatory Assistance Project. <https://www.raponline.org/knowledge-center/revenue-regulation-and-decoupling-a-guide-to-theory-and-application-incl-case-studies/>

revenue per customer (RPC) method.¹⁰⁹ As the name of this method indicates, the annual revenue target in between rate cases is adjusted to reflect changes to the number of customers. This particular method acts as a short-term barrier to electrification efforts as well as any measures necessary to slow the addition of new gas customers. In this method:

$$\text{Revenue per customer TEST PERIOD} = \frac{\text{Revenue requirement TEST PERIOD}}{\text{Number of customers TEST PERIOD}}$$

$$\text{Revenues ALLOWED} = \text{Revenue per customer TEST PERIOD} \times \text{Number of customers ACTUAL}$$

$$\text{Price ACTUAL} = \frac{\text{Revenues ALLOWED}}{\text{Units sold ACTUAL}}$$

As a result, an increase in the actual number of customers causes the revenue target to go up, and a decrease in customers causes the revenue target to go down. Such a method can be rational, particularly for steadily growing utilities, because new customers typically do mean new investments and expenses for a utility. RPC decoupling is one method of accounting for such growth between rate cases, which is one reason why gas utilities have been receptive to the concept.¹¹⁰

As long as the calculated revenue per customer is higher than marginal costs, there is a strong incentive built into RPC decoupling for utilities to increase profits by adding customers and to strongly resist policies that could mean losing customers. In the context of a future where many customers will likely switch from gas service to other low- and zero-GHG alternatives, RPC represents a barrier to needed planning reforms, as well as to any policies that promote fuel switching.

Numerous other methods to set the revenue target for decoupling do not strongly incentivize a gas utility to add customers or resist losing customers. Switching to a method that does not include a per-customer annual adjustment should still remove a short-term barrier to energy efficiency and beneficial electrification for gas customers between rate cases. The decoupling method can include either a flat revenue target over time (sometimes called true decoupling) or a method that adjusts yearly revenue for inflation, productivity improvements and other factors (also known as attrition decoupling).

Consider Performance-Based Regulation for Gas Utilities

While decoupling addresses a utility's incentive to sell more gas, that incentive is not the only bias built into traditional utility rate-making. In addition, there is a well-known phenomenon where utilities are likely to overinvest in capital because such investments are the main source of profit in a traditional revenue requirement. This incentive to overinvest in capital can undermine reforms to gas planning and programs that envision reduced gas utility investment. While increased regulatory scrutiny during rate cases (and the ability of a regulator to rule that certain capital investments were imprudent) can help address this issue, performance-based rate-making is another prominent method. Although there is no universally accepted definition of performance-based rate-making, key elements include multiyear rate plans and performance incentive mechanisms for the achievement of specified objectives.¹¹¹

109 Examples of revenue-per-customer decoupling for gas utilities include Massachusetts, Rhode Island and previously New York. See NSTAR Gas Co. (2019, November 8). *Direct testimony of William J. Akley and Douglas P. Horton*, pp. 79-81. Massachusetts Department of Public Utilities Docket No. 19-120. <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/11419982>. See also Rhode Island Public Utilities Commission Docket Nos. 4770 and 4780, Amended settlement agreement, August 16, 2018, pp. 81-82. <http://www.ripuc.ri.gov/eventsactions/docket/4770-4780-NGrid-Compliance%20Filing%20Book%201%20-%20August%2016.%202018.pdf>. In its most recent rate case, the gas decoupling mechanism for ConEd in New York was changed from an RPC model to an aggregate "revenue per class" model. As the Public Service Commission explained: "The gas [decoupling] modification is consistent with the Commission's recognition that incentives that reward utilities for expanding their gas customer base should be eliminated while we consider policy changes that may need to occur to address important environmental issues, including the promotion of cost-effective energy conservation, the increased use of renewable resources, and the decreased use of fossil fuels." New York Public Service Commission, Case No. 19-G-0066,

Order adopting the terms of joint proposal and establishing electric and gas rate plan, January 16, 2020, p. 23. <http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=19-G-0066&CaseSearch=Search>

110 For many utilities, revenue-per-customer decoupling can be additionally attractive if the mix of new customers is denser and more efficient — and thus less costly — than old customers. Thus, using the historic average cost per customer overcompensates the utility for adding new customers. This can be adjusted for by using a lower average cost for newly added customers.

111 In the context of electric utilities, RAP has written extensively on these issues. See, for example, Littell, D., Kadoch, C., Baker, P., Bharvirkar, R., Dupuy, M., Hausauer, B., Linvill, C., Migden-Ostrander, J., Rosenow, J., Wang, X., Zinaman, O., & Logan, J. (2017). *Next-generation performance-based regulation: Emphasizing utility performance to unleash power sector innovation*. Regulatory Assistance Project: <https://www.raponline.org/knowledge-center/next-generation-performance-based-regulation-emphasizing-utility-performance-unleash-power-sector-innovation/>

Multiyear rate plans with a stay-out period, where the utility and commission have committed to avoid a new rate case for a specified number of years, can be a key element of performance-based regulation schemes. Multiyear rate plans, often packaged with decoupling, are now relatively common for both gas and electric utilities.¹¹² During a multiyear rate plan, the precommitment of the stay-out period provides a greater incentive for a utility to improve profits by constraining costs and operating efficiently. Ideally, these efficiencies are passed along to ratepayers in the next rate case because they show up as lower costs in the test year for the new rate case.

This incentive within a multiyear rate plan can, however, be undermined by the use of adjustment factors (often colloquially known as trackers) to update certain cost categories between rate cases. At a minimum, careful thought must be put into how tracker costs and costs in base rates are coordinated. There is a general risk in approving trackers that utilities only seek them for categories of costs that are increasing over time, while ignoring cost categories that may be decreasing. This is one of the reasons for the general presumption against single-issue rate-making because changes in costs may counteract one another. As a result, a general best practice is to limit the use of trackers to categories of costs that are not in the utility's control and are not correlated with other changes in utility costs.¹¹³ In addition, automatic cost recovery in a tracker presents an incentive for a utility to pursue qualifying expenses and investments. In particular, infrastructure replacement cost trackers, which are becoming more common for programs to replace gas distribution mains, are easy procedurally for utilities to recover costs and provide a substantial investor return on expensive additions to rate base. Reforming the planning framework and investment criteria is important in this context, but this utility business model issue should be addressed as well.

A potential downside to multiyear rate plans is that they can overincentivize cost cutting, at the expense of customer

service or other elements of utility performance. A best practice is to use service quality metrics, which often take the form of financial incentives that penalize a utility for poor reliability and customer service.

More generally, metrics and performance incentives — especially financial incentives — can help pivot a utility's business model away from continued capital expansion and toward more important public policy goals, including decarbonization, system efficiency and customer service.

Several different ways to set up a performance incentive scheme are being explored across the United States for electric utilities. Among the purposes for adopting a performance system of regulation are to better align the management of the utility and its outputs with public interest priorities and outcomes laid out by government and to promote innovation. One alternative is to set up a system of penalties and rewards while keeping most other rate-making features the same. Another alternative is to reduce the baseline return on equity built into the revenue requirement but to allow the utility to achieve a typical profit level with good performance — or even to exceed a typical profit level with excellent performance. Furthermore, reducing the baseline return on equity for capital investments has the related virtue of dulling the capital investment bias directly and should pass legal muster as long as the baseline return on equity is higher than the utility's actual cost of capital in the market.

The actual details of performance incentive schemes for gas utilities can be quite flexible. Some options include:

- Service quality incentives.
- Reliability and safety incentives.
- Methane leakage reduction incentives.
- Peak demand reduction or system load factor improvement incentives.
- Incentives for fair treatment of low-income ratepayers, such as enrollment in discount rates, prevention of disconnections or management of repayment plans.

112 Lowry, M. N., Makos, M., & Deason, J. (2017, July). *State performance-based regulation using multiyear rate plans for U.S. electric utilities*. Lawrence Berkeley National Laboratory. <https://emp.lbl.gov/publications/state-performance-based-regulation>

113 One example of cost correlation is infrastructure modernization trackers. If an older technology would normally be financed out of base rates, then investment in a newer technology through a tracker can be looked at as double counting until the next rate case. The utility avoids the traditional financing cost as well as receiving the new tracker revenue.

- Broad decarbonization incentives, either economywide or for the heating sector; specifically, such an incentive would induce a gas utility to take steps to lower the GHG emissions from its own system but also to be part of broader efforts within the state.

Across the country, we would expect significant variations based on different public policy priorities. Changing incentives for a gas utility can help lower opposition to key reforms and enlist the utility as a partner in important public policy efforts.

Alternative futures for the current gas utility

In this section, we have addressed the incentives that gas local distribution companies currently face. There is a broader range of potential structural reforms that utilities and the larger corporations that own most gas utilities may want to consider.

Potential futures for the corporation that is currently a gas LDC include the following.

Zero-carbon gas delivery: With appropriate handling of costs over time, the gas utility could perform the same gas delivery function but with a smaller footprint serving a limited number of customers with green hydrogen or renewable methane.

Fusion with an electric utility: Although many utilities currently operate both gas and electric utilities, these are currently managed and financed as two separate entities. As the gas side of this arrangement shrinks, there may be a natural pathway to deliberately and equitably merge these two entities. Such a solution may be simpler where the relevant gas and electric service territories largely overlap.

Expanded natural monopoly provision: In many service territories, a gas utility could add zero-carbon district energy systems with appropriate statutory permission and regulatory approvals. District energy systems are also a natural monopoly and include a related set of competencies of underground infrastructure development and maintenance. This new “energy delivery through pipes” company would have more viable expansion options and may have improved financial integrity and ability to attract capital. Regulators

would still need to answer key questions about rates and cross-subsidies across services provided by such an entity.¹¹⁴

Conversion to a public entity or cooperative: A new ownership model may be better suited to manage the transition with the broader public interest in mind. Such a conversion may also more fairly enable the usage of general taxpayer funding without the appearance of subsidizing shareholders.

Energy or heating services provider: A gas utility could be allowed to expand into areas that are not natural monopolies but rather related to general utility expertise in energy or heating services. This concept raises even harder questions about how customers pay for those services and fair treatment of existing businesses that compete in this space with unregulated capital. Such a transformation may be best accomplished by converting the regulated entity into an unregulated one, where cost recovery is no longer guaranteed but its considerable resources and expertise can be leveraged in new ways.

In addition, the conglomerates that typically own gas utilities are often diversified across different energy assets, including electric utilities. Although such a conglomerate would rarely welcome any business unit to consistently be a drain on its broader finances, losses in one area can be made up for in other areas. Management and shareholders in these broader conglomerates will have a more diverse array of interests and incentives.

114 This concept is being explored with pilots for district energy systems in Massachusetts. Gerdes, J. (2020, August 6). *Massachusetts pilot project offers gas utilities a possible path to survival*. Greentech Media.

<https://www.greentechmedia.com/articles/read/can-gas-companies-evolve-to-protect-the-climate-and-save-their-workers>

VI. Conclusion

Regulators are at the forefront of ensuring that utilities meet consumers' needs efficiently, equitably and fairly. This mission is made more complex by large shifts in the energy system driven by state and local greenhouse gas reduction targets and increasingly competitive technology innovations. Regulators can use familiar building blocks of solid utility regulation in new ways to prepare for and respond to changing circumstances and public expectations. In this report, we provided options and recommendations to create this consumer-oriented foundation, including outlining

a revitalized gas utility planning process, enhancements for energy efficiency and electrification programs, and means to reform rate-making to enable and promote equitable and efficient outcomes. By using these tools, regulators can augment regulation of gas utilities in general and specifically create an environment in which transition can occur. We offer this report as the initial framework for this new challenge. We will dive into more specific means of addressing this changing area in future reports on this topic.

VII. Appendix: Basics of Gas System Operation and Regulation

The history of methane combustion in the United States and its delivery through pipes underground dates back to the 19th century. Until the middle of the 20th century, most of this methane was manufactured gas, made from feedstocks such as coal (a process that led to substantial ground and water pollution). As the extraction of methane from underground became a bigger part of the industry, along with the necessary infrastructure to transport that gas, the term “natural gas” was used to distinguish extracted gas from manufactured gas. Extracted methane, even with the cost of long-distance delivery, was generally more economically competitive with electricity and oil than manufactured gas and was adopted widely in the middle of the 20th century.¹¹⁵ Where it was too hard to extend the interstate gas transmission network to a community served by manufactured gas, the gas distribution system was retired, and customers found other ways to meet their energy needs.¹¹⁶

Since that time, fossil methane has turned into a major national market with its own specialized federal and state regulatory frameworks. While much of the gas system has operated in the same manner for decades, the changing economic and public policy context is putting pressure on the existing regulatory framework. This appendix explains the basics of how the gas system operates and current regulations governing the system.

A. Basics of Gas System Operation

Methane, like all gases, travels based on pressure differentials: Molecules move from higher pressure toward lower pressure. Methane trapped underground at high pressure is looking for a way out. Conventional underground gas deposits often lie underneath a layer of rock and frequently can be found as associated gas alongside oil deposits. Since the beginning of the 21st century, advanced drilling techniques (e.g., horizontal drilling and hydraulic fracturing, or fracking) have allowed “unconventional” gas deposits to be accessed more easily.

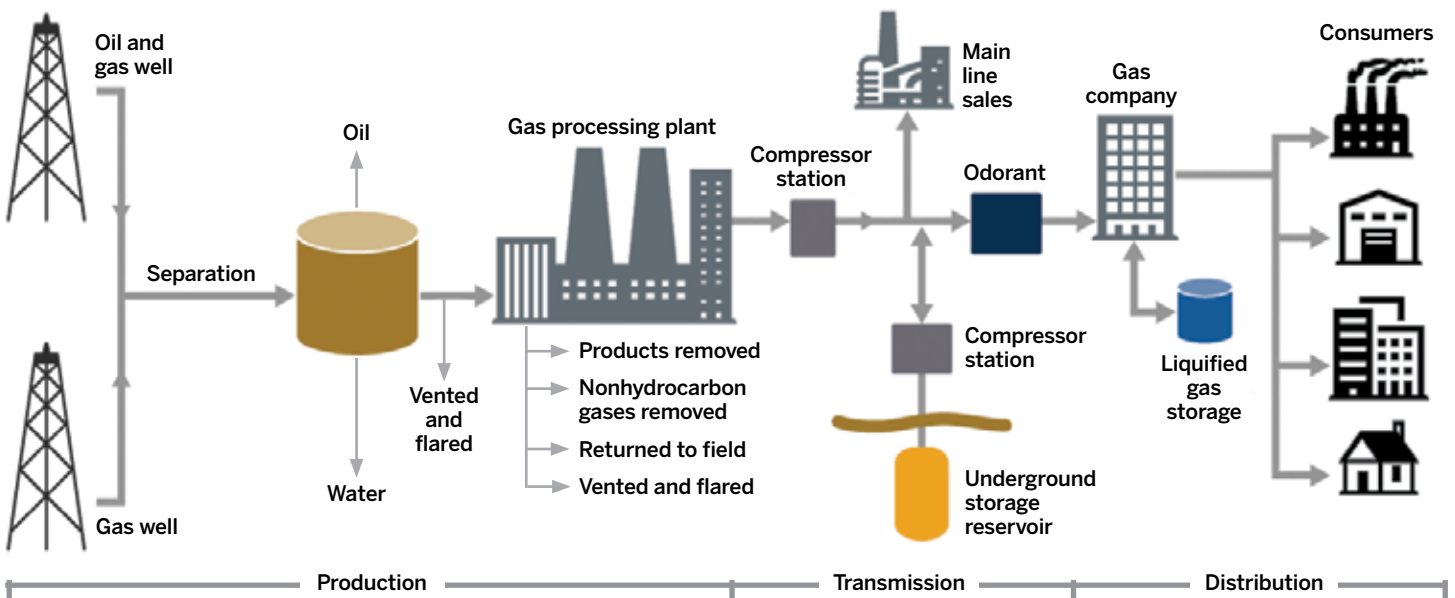
From the wellhead, extracted gas must be sent to processing plants to have impurities removed, and then it is ready for transportation. Gas is typically transported via large transmission pipelines, but it can also be liquified (in this form it is known as liquified natural gas) and transported by ship or truck. Many electric power facilities and large industrial customers are served directly by transmission pipelines; the remainder of the gas that flows through transmission pipelines is delivered to local gas utilities. The point of connection between the transmission system and the local distribution network is typically known as a gate station or city gate. At the city gate, the gas is odorized so that leaks can be detected, and then it is delivered to homes and businesses through smaller pipes. The shared distribution pipes that are often under streets are referred to as mains, and the final pipe that connects to an individual metered location is known as a service line or just a service. Figure 18 on the next page depicts the steps in gas production and delivery.¹¹⁷

115 Garfield, P., & Lovejoy, W. (1964). *Public utility economics*, pp. 167-169. Prentice Hall. Although both compounds were predominantly methane, there were some important chemical differences between manufactured gas and the extracted product. For the preexisting gas utilities, predominantly in major cities, this transition required some substantial improvements to their distribution infrastructure. In addition, customer appliances that had previously used manufactured gas had to be adapted to utilize methane extracted from the ground.

116 Hatheway, A. W. (2018, March 26). *Locations of gas plants and other coal-tar sites in the U.S.: The state of Vermont*. Former Manufactured Gas Plants. http://www.hatheway.net/state_site_pages/vt__main.htm

117 U.S. Energy Information Administration. (2020, November 30). *Natural gas explained: Delivery and storage of natural gas*. <https://www.eia.gov/energyexplained/natural-gas/delivery-and-storage.php>

Figure 18. Fossil gas production and delivery



Source: U.S. Energy Information Administration. (2020, November 30). *Natural Gas Explained: Delivery and Storage of Natural Gas*

The speed of gas flow can be observed and measured during this journey, often between 10 mph and 30 mph. Unlike fluctuations in the electricity system, changes to gas pressure take time to propagate through the system, and pressure must be maintained within certain bounds to ensure safe and reliable operation. Each segment of the gas transportation system is designed to handle different levels of pressure. Large transmission pipelines operate at much higher pressures than local distribution mains and services. If gas pressure becomes too high for a given segment, safety systems are designed to reduce the pressure; if those fail, disaster can result.¹¹⁸ Conversely, if the pressure goes too low in a section of the pipe that serves customers, the system typically needs to be shut down, and lengthy safety checks may be necessary to resume the flow of gas.¹¹⁹

Compressor stations, which typically use gas to power

their operation, pressurize the system to move gas over long distances. For efficient operation, such compressor stations are needed every 40 to 100 miles along a major transmission pipeline.¹²⁰ In addition, gas control stations of varying levels of sophistication are placed along a transmission line to monitor and control the flow of gas. Valve shutoffs are included every few miles along a pipeline.

At the distribution level, pressure also needs to be maintained within a certain range. Smaller compressor stations are sometimes used to ensure proper flow, and pressure regulators and relief valves are used along the system to ensure that pressure stays within the right bounds. In a modern gas system, many of these components are automated or operated remotely, but an older gas system may not have those capabilities. Shutoff valves are often installed every so often along a distribution main.

118 Commonwealth of Massachusetts. (2020, January). *Merrimack Valley natural gas explosions after action report: September 13-December 16, 2018*. <https://www.mass.gov/doc/merrimack-valley-natural-gas-explosions-after-action-report/download>

119 See State of Rhode Island Division of Public Utilities & Carriers. (2019, October 30). *Summary investigation into the Aquidneck Island gas service interruption of January 21, 2019: Investigation report*. http://www.ripuc.ri.gov/eventsactions/AI_Report.pdf. If pilot lights go out

because of a lack of gas, then resuming the flow can lead to a dangerous methane release, among other problems.

120 Messersmith, D. (with Brockett, D.). (2015, March 26). *Understanding natural gas compressor stations*. Penn State Extension. <https://extension.psu.edu/understanding-natural-gas-compressor-stations/>

There are risks of gas leakage from the point of extraction to the end use.¹²¹ During production, gas may accidentally leak or be deliberately vented or flared. Venting is when gas is simply released to the atmosphere. With flaring, a company will burn the gas on-site to eliminate excess, which converts the methane to carbon dioxide and water. Venting and flaring are used to control pressure, to eliminate excess gas when there is not sufficient infrastructure to capture or transport all of the gas extracted, or when the gas is a byproduct of oil extraction and gas prices do not warrant bringing it to market. Pipes transporting gas to processing plants and later to the distribution system may have additional leaks. A study published in *Science* demonstrated that methane emissions from the U.S. supply chain in 2015 constituted 2.3% of gross U.S. gas production, equivalent to the amount of gas supplied to fuel 10 million homes.¹²² A 2020 American Chemical Society study found that gas leakage in distribution lines is almost five times as much as the EPA estimates.¹²³

Distribution system leaks can present health and safety risks. The rate of leakage on the distribution system can be hard to quantify because few gas system locations have monitoring equipment to measure exact quantities, and the expense of such equipment makes it unlikely that it will be widely deployed without an affirmative requirement.¹²⁴ Finally, gas leaks, inefficiencies and combustion byproducts may occur at the point of end use, degrading indoor air quality and harming health.¹²⁵

Unlike in the electricity system, storage has long been a common feature of the efficient operation of the gas system. Underground rock formations or depleted oil or gas reservoirs are used for bulk storage. More local storage, which is often used as fuel to serve peaks in demand, can be in large metal tanks, either as pressurized gas or in liquid form. The network of gas pipelines also operates as a storage system, unlike the electric grid, which cannot retain reserves. Gas molecules can be stored in the pipes within the relevant pressure ranges. At a higher pressure, more gas molecules are being stored, so the different segments of the system can be controlled to provide in advance for higher (or lower) expected demands. This is generally known as linepack. As customers consume gas, the pressure in the system becomes lower unless additional supplies are moved into the relevant pipe segments. In other words, unexpectedly high gas consumption is one of the causes of low pressure in the distribution system and could require additional utility action to correct. Last, there are alternative ways to introduce gas into the distribution system, other than transmission pipelines or centralized LDC storage. Either liquified natural gas, compressed natural gas or propane can be shipped or trucked to certain points on the distribution system, appropriately converted and then stored or injected directly to ameliorate low pressure conditions or as a peak-shaving technique.

121 Methane, the primary component of piped gas, has a 20-year global warming potential at least 84 times that of carbon dioxide. Global warming potential is a measure used to compare the contribution of different greenhouse gases to global warming. Carbon dioxide, with a global warming potential of 1, is used as the baseline; the higher the global warming potential of other gases, the greater the impact over a set period of time. Methane has a shorter atmospheric lifetime than carbon dioxide, but its impact during that time is much greater than that of carbon dioxide. Intergovernmental Panel on Climate Change. (2013). *Climate change 2013: The physical science basis*, pp. 664-665, 714. (T. F. Stocker, D. Qin, G.-K. Plattner, M. Tignor, S. K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P. M. Midgley, Eds.). Cambridge University Press. <https://www.ipcc.ch/report/ar5/wg1/>

122 Alvarez, R. A., Zavala-Araiza, D., Lyon, D. R., Allen, D. T., Barkley, Z. R., Brandt, A. R., Davis, K. J., Herndon, S. C., Jacob, D. J., Karion, A., Kort, E. A., Lamb, B. K., Lauvaux, T., Maasakkers, J. D., Marchese, A. J., Omara, M., Pacala, S. W., Peischl, J., Robinson, A. L., ... Hamburg, S. P. (2018, July 13). Assessment of methane emissions from the U.S. oil and gas supply chain.

Science, 361(6398), 186-188. <https://science.sciencemag.org/content/361/6398/186>. See also Schwartz, J., & Plumer, B. (2018, June 21). The natural gas industry has a leak problem. *The New York Times*. <https://www.nytimes.com/2018/06/21/climate/methane-leaks.html>

123 Weller, Z. D., Hamburg, S. P., & von Fischer, J. C. (2020, June 10). A national estimate of methane leakage from pipeline mains in natural gas local distribution systems. *Environmental Science & Technology*, 54(14), 8958-8967. <https://doi.org/10.1021/acs.est.0c00437>. See also The Gas Index, 2020.

124 Gas leaks can also be monitored and estimated through a variety of techniques outside of the gas system. See, for example, Plant, G., Kort, E. A., Floerchinger, C., Gvakharia, A., Vimont, I., & Sweeney, C. (2019, July 19). Large fugitive methane emissions from urban centers along the U.S. East Coast. *Geophysical Research Letters*, 46(14), 8500-8507. <https://doi.org/10.1029/2019gl082635>

125 Seals & Krasner, 2020; Seals, 2020.

B. Creation of Current Regulatory Framework

State regulation of gas utilities began in the early 20th century, when most deliveries were of manufactured gas.¹²⁶ As with electric utilities, this regulation included the power to set just and reasonable rates for gas utilities, along with the regulation of other characteristics of gas service and tariffs. These rates have largely been based on cost of service principles, as they are for many other types of utilities.

The federal regulatory role in this area started with the Natural Gas Act of 1938, which gave jurisdiction over interstate gas pipelines to the Federal Power Commission (which later became the Federal Energy Regulatory Commission, or FERC).¹²⁷ Substantively, this jurisdiction originally included permitting interstate pipelines and the rates for those pipelines but later expanded to price regulation for commodity gas sold over those pipelines. The Natural Gas Policy Act of 1978, part of a broader package of legislation that included the Public Utility Regulatory Policies Act, made a number of changes to the federal regulatory scheme, including the addition of intrastate gas production to FERC's jurisdiction and a timeline to deregulate commodity prices for new wells. FERC took additional steps to allow industrial customers to purchase gas as a commodity and receive delivery over interstate pipelines, without the intermediary of a state-regulated gas utility. This change, which was voluntary, allowed pipeline operators to offer nondiscriminatory access to pipelines, marking the beginning of open access to gas transmission pipelines, as well as the creation of gas marketers. In 1989, another federal

law was passed to fully deregulate the first sale of commodity gas from all wells. In 1992, FERC issued Order 636, which completed the restructuring of the interstate gas pipeline industry, requiring pipelines to offer transportation service on a nondiscriminatory basis. It also separated pipeline entities, production entities and marketing entities into arm's-length affiliates.

Within this federal context, the state-jurisdictional gas utilities still offer bundled service, where they buy commodity gas and pay for it to be transported on behalf of their customers. Commodity gas can be purchased by utilities on a contract or spot basis, and costs can be managed over time. Nearly all LDCs have purchased gas adjustment clauses, through which supply costs, including transmission, storage and gas commodity costs, are flowed through to retail rates. Some jurisdictions allow retail choice, where the customer contracts with a gas marketer for gas supply. These customers still pay the relevant distribution rates for the gas utility as approved by the regulatory commission, which are frequently called transportation rates. It is important to clearly distinguish retail choice, where a customer is still served by a local gas utility and pays a distribution rate, from transmission-level open access policies, where the customer bypasses the local gas utility entirely.

Regulators will continue to make decisions to ensure that the regulation of gas utilities is aligned with the public interest and changing circumstances. As the usage of fossil gas wanes, the regulation of gas utilities will necessarily evolve. Regulators can use the tools and recommendations outlined in this report to write the next chapter of our gas systems.

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