IMPACT OF ELECTRIFICATION AND DECARBONIZATION ON GAS DISTRIBUTION COSTS

Steven Nadel

June 2023
ACEEE Report

Smart Energy. Clean Planet. Better Lives.

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About ACEEE

The **American Council for an Energy-Efficient Economy** (ACEEE), a nonprofit research organization, develops policies to reduce energy waste and combat climate change. Its independent analysis advances investments, programs, and behaviors that use energy more effectively and help build an equitable clean energy future.

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Acknowledgments

This report was made possible through the generous support of A.O. Smith, the Tilia Fund ad the U.S. Department of Energy. The authors gratefully acknowledge external reviewers, internal reviewers, colleagues, and sponsors who supported this report. Internal reviewers included Michael Waite, Amy Bell-Pasht, Mark Kresowik, Edward Yim, and Mariel Wolfson. The authors also gratefully acknowledge helpful comments on a review draft of this report from Holly Braun at NW Natural, Brandy Chambers and Nikki Bruno at Eversource, Josh Greene at AO Smith, Mark LeBel from the Regulatory Assistance Project, Dorie Seavey (an independent consultant on gas distribution issues), Ragu Sudhakara from Con Ed, and Michael Walsh and Michael Bloomberg from Groundwork Data. External review and support do not imply affiliation or endorsement. Last, we would like to thank Ethan Taylor for managing the editing process, Jacob Barron for copy editing, Roxana Usher for proofreading, Kate Doughty for graphics design, and Mark Rodeffer for their help in launching this report.

Suggested Citation

Nadel, S. 2023. *Impact of Electrification and Decarbonization on Gas Distribution Costs*. Washington, DC: ACEEE.

Key Findings

- Electrification has been found by other studies to be the lowest-cost route to decarbonization for most U.S. homes. As more homes are electrified and leave the gas system, under current policies fixed gas system costs will be reallocated to remaining customers. We looked at illustrative scenarios with 25%, 50%, and 75% electrification, finding that average gas utility costs per customer can increase 21%, 43%, and 129%, respectively.
- Replacement of aging gas pipes can also be expensive. We looked at several scenarios with increased capital budgets for pipe replacement. Utility costs per customer ranged from an increase of 15% under a scenario assuming minimal pipeline replacement up to 106% if many older gas pipes are replaced.
- In scenarios we examined that combine electrification, gas pipe replacement, and use of biofuels, utility costs per customer increased 172–544%, with higher increases associated with greater electrification, pipeline replacement, and reliance on biogas.
- If an individual customer chooses to electrify 75% or 90% of their load and retain gas service for backup heating or cooking, in our illustrative scenarios, their gas bill would decline about 35% or 40%, respectively, with the vast majority of their remaining bill attributable to the costs of capital, administration, and taxes. Innovative rates have been suggested to address combined costs for hybrid heat customers.
- Alternative fuels such as biogas are another path to decarbonization but these will be expensive. In our biogas scenario, average utility costs per customer increase by about a factor of four (300%).
- Across these different scenarios, it is clear that residential and commercial gas service will become significantly more expensive as states, cities, and utilities move to decarbonize their systems and also address safety problems that will affect some aging pipes (the range of scenario costs is illustrated in figure ES-1 on the next page). Pipe replacement costs could be reduced or deferred by repairing pipes rather than replacing where possible.
- Costs will generally be higher in urban areas with old gas pipes that need replacement as well as in rural areas (fewer customers per mile of pipe). For these areas, strategically targeting certain neighborhoods for electrification that would allow decommissioning specific gas lines could mitigate cost increases for remaining customers. We found reduced utility costs per customer in an illustrative scenario using this approach.
- Comprehensive weatherization packages can help reduce energy use and bills. They will be particularly important in high-cost scenarios involving expensive alternative fuels extensive electrification and/or extensive gas pipe replacement.
- Costs for remaining gas customers are small in the early stages of electrification but grow rapidly with high electrification percentages. Strategic long-term planning should begin before the impacts of cost growth manifest and may include innovative financial structures, community or neighborhood targeting, and region-specific decarbonization solutions.

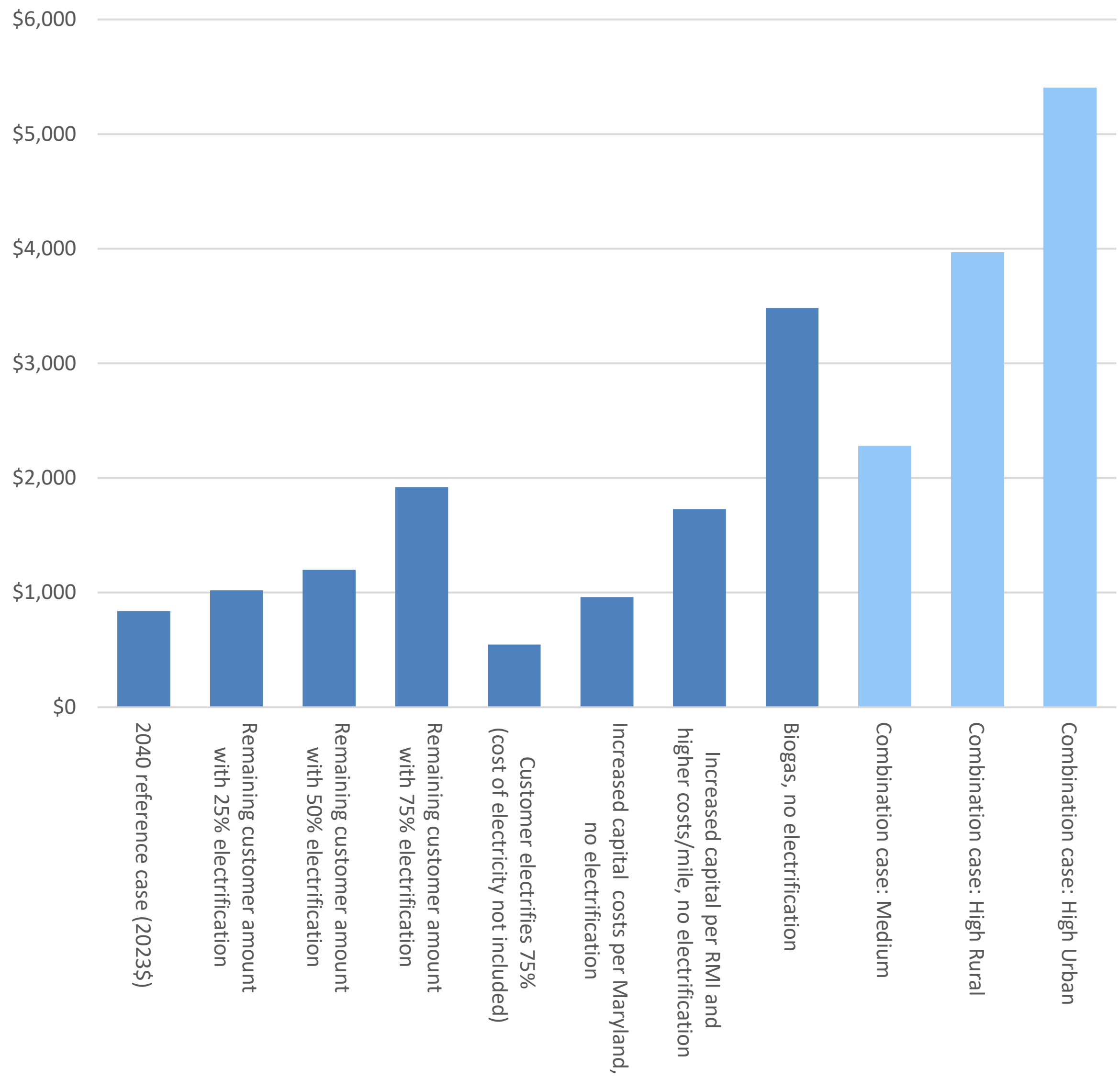

Figure ES-1. Costs per customer to the utility in 2040 under some of the scenarios examined in this report. Except for the three combination scenarios at the end, all of the other scenarios involve just a single change and should be compared to the reference case. The combination cases are described below

Combination scenarios	Description
Medium	50% electrification; medium gas capital costs per plans in Maryland; half of remaining gas customers use fossil gas and half use biogas.
High rural	75% electrification, 100% biogas for remaining customers, rural area capital-related expenditures.
High urban	75% electrification, 100% biogas for remaining customers, urban area capital-related expenditures, higher capital costs per the RMI estimate.

Introduction

DECARBONIZATION

Increasingly, governments, utilities, and many businesses and consumers are looking to dramatically reduce carbon emissions in order to protect the climate and deliver benefits to communities and households. One significant source of carbon emissions is burning natural gas in homes and businesses to provide heat and hot water, to cook, and for other uses. According to the Energy Information Administration (EIA), natural gas accounts for 34% of U.S. energy-related carbon emissions including 28% of residential emissions and 23% of commercial sector emissions (EIA 2022).[1] In order to dramatically reduce these emissions, two major approaches have been proposed: electrification and use of alternative fuels.

Electrification involves replacing fossil fuel-fired equipment with equipment that instead uses electricity. Efficient electric appliances reduce pollution in most of the United States today and will have an even more positive impact in the future as coal-fueled power plants retire and clean electricity generation increases. With electrification, fossil fuel-fired equipment might be replaced with high-efficiency electric heat pumps for space heating and cooling, heat pump water heaters, induction stoves for cooking, and heat pump clothes dryers.

Another approach is for gas utilities to distribute alternative fuels with low net carbon emissions to its customers. This approach would involve partially or completely replacing gas in the distribution system with alternative fuels such as biofuels, hydrogen or synthetic natural gas produced from renewable sources. Hydrogen has zero carbon emissions if the hydrogen fuel is made with zero-emissions electricity. Biofuels and synthetic natural gas do release carbon dioxide when they burn and methane (also a greenhouse gas) when they leak, but some biofuels could potentially displace equivalent emissions in their production. For example, biofuels can be made from plants that remove carbon dioxide from the atmosphere as they grow, or can be made from animal excrement or landfills, which, if not used to produce fuel, would instead release methane into the atmosphere as the waste breaks down in the environment. However, most of these fuels do have some carbon emissions that will need to be offset and their potential production falls far short of current natural gas usage (Nadel 2022). We also note that this discussion applies to fuels with very low emissions; mixing moderate amounts of these fuels with natural gas will retain most of today's emissions from natural gas.

Energy efficiency measures, such as building envelope improvements, can play an important role with both electrification and alternative fuels. The more that energy efficiency is

[1] These figures include gas used to generate power, including the power that is consumed in the residential and commercial sectors.

employed, the less electricity and alternative fuel that is needed, reducing both operating costs and the amount of capital investment needed to supply electricity or alternative fuels (Nadel 2022; Nadel and Fadali 2022).

THE GAS DISTRIBUTION SYSTEM

Sixty percent of homes in the United States rely on natural gas for space and water heating and/or cooking (EIA 2023d). This gas is generally provided via distribution pipes installed and maintained by local gas distribution utilities. Decarbonization will have a profound effect on these gas utilities. As buildings are electrified, gas sales by the utilities will decline, the number of gas customers can decrease, and costs for remaining gas customers are likely to increase as fixed costs are spread over fewer customers. To the extent alternative fuels are used, depending on the fuel, the gas distribution system and sometimes individual appliances will need to be modified or replaced. As we discuss later in this report, alternative fuels can be very expensive, which will also affect the demand for fuels.

At the same time, many older gas distribution systems require investments to maintain safe and reliable service; as we discuss later in this report, in some systems these upgrades can cost billions of dollars.

Decarbonization's effects on the gas system and customer costs will differ for different utilities depending on a variety of factors including load density, climate and peak demands, current and expected future gas system upgrade needs, the scale and extent of electrification, the current gas-powered end uses in buildings that electrify, and feasibility of distributing decarbonized gas and the cost of gas system modifications that may be needed to handle alternative fuels.

A previous study by Davis and Hausman (2022) of University of California, Berkeley's Haas School of Business began to systematically look at some of these issues. That study used retrospective data to look at one aspect of gas industry change—the impact of a declining number of customers (at least partially due to electrification) on utility infrastructure and customer costs. As summarized in the paper abstract:

> Using historical evidence from growing and shrinking U.S. natural gas utilities, we show that utilities add pipelines but rarely remove them, even when the customer base from which to recover costs is shrinking. Correspondingly, we find that utility revenues decrease less than one-for-one when a customer base is shrinking, consistent with higher bills for remaining customers (Davis and Hausman 2022).

Based on their empirical findings, they projected the impact of customer departures on costs for remaining customers. This estimate is summarized below in figure 1, which shows exponential growth as customers exit the system. For example, their midpoint estimate is that if 50% of gas customers leave the system, the average customer bill will increase about 60%. Yet, if 75% of gas customers leave the system, the average customer bill would increase by 150%.

The impact of electrification on gas distribution costs was also included in several analyses by the consulting firm E3 on decarbonization options for gas customers in several states, although in these studies multiple variables are combined and the impact of any one variable is generally not isolated (Maryland Commission on Climate Change 2021; GPI and CEE 2021; E3 2022; Olson et al. 2021).

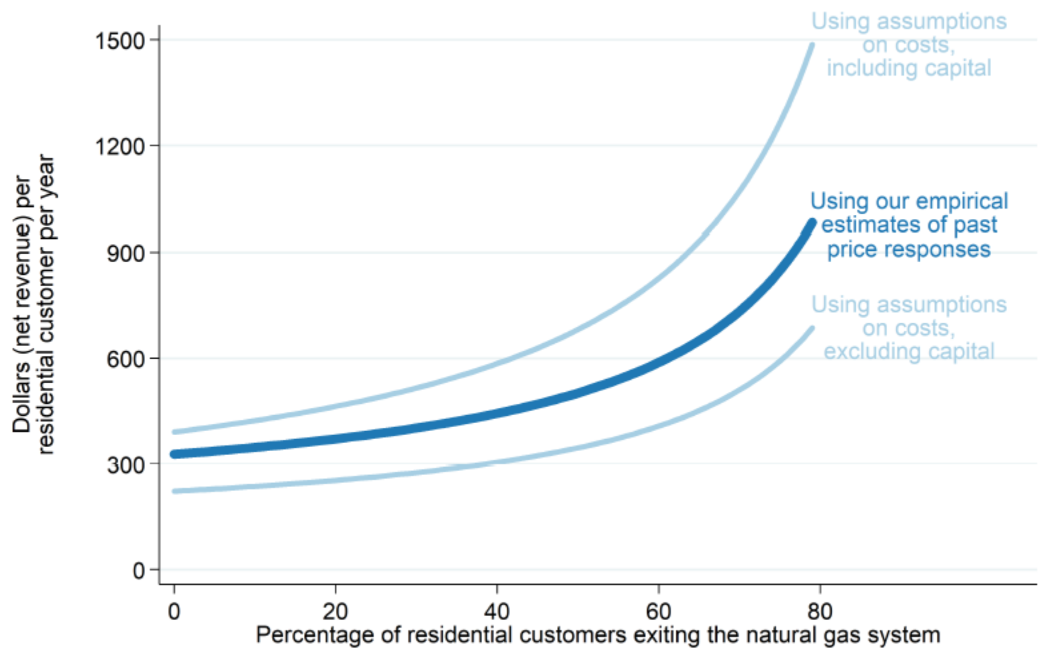

Figure 1. Effect of customer exit on energy bills for remaining customers. Source: Davis and Hausman (2022).

However, Davis and Hausman looked at only one aspect of these issues—the number of remaining customers—and did not look at other factors that will affect the gas distribution system and customer costs, such as replacement of old gas pipes and the role of energy efficiency. To complement the Haas study, we must look systematically and prospectively at the impacts of electrification and decarbonization at scale, and at the implications for energy policy and gas system planning. This study is an initial attempt to look at some of these issues through a scenario analysis.

RESEARCH QUESTIONS

- What is the impact of electrification of natural gas building end uses on gas distribution system costs and their impact on natural gas customer rates?
- How are gas distribution costs affected by the concentration/dispersion of electrification within a gas distribution system?
- How do gas distribution costs and their impact on costs differ by gas system density, climate, and gas system upgrade needs?

- What is the impact of different estimates of future natural gas costs and of reliance on biofuels instead of natural gas for customer costs?
- How will energy efficiency investments affect customer costs under these different scenarios?
- What are the implications of the modeled scenarios and results for policy and planning?

The goal of this report is to assist utility regulators and other policymakers, utilities, and other interested parties with an exploratory analysis of the impacts of electrification and other selected decarbonization strategies on gas delivery pricing as they consider gas distribution system investments and long-term plans. Exploring different situations will help them understand the issues and potential outcomes as they seek to frame the questions they should ask and to make decisions on system upgrades, maintenance, and retirement. Thus, the prime audience for this study is staff at utilities, utility commissions, and other key stakeholders that need to understand the impact of electrification and decarbonization on gas distribution and decarbonization costs as they explore electrification, alternative fuels, and gas system cost recovery options.

Methodology

Our basic approach is to take data compiled by the American Gas Association (AGA) on *Performance Benchmarks for Natural Gas Utilities*, as analyzed by Davis and Hausman (2022). We use this as a foundation to project future costs, first in a business-as-usual reference case scenario and then in a set of alternative scenarios that address

1. Different degrees of electrification;
2. Additional capital costs to replace aging infrastructure;
3. Variations in costs by neighborhood density (urban, suburban, and rural);
4. Different prices for natural gas and alternative fuels;
5. Regional differences;
6. Combinations of some of these variations; and
7. Impact of energy efficiency investments across several of the scenarios.

Our analysis focuses on the delivery portion of customer gas bills, but we also include some scenarios that look at changes in gas supply prices in order to put the relative contribution of fuel and delivery costs in perspective. We focus on average utility costs per customer, including a rate of return on investments. Retail rates need to be set at levels that cover these costs. This study does not get into electrification economics or the details of how electrification might be implemented; our focus is on how electrification and other decarbonization strategies can affect the gas distribution system.

COSTS, RATES, AND BILLS

In this study, our primary metric is the average utility cost to serve a customer, including a rate of return on their investments. Utilities and their regulators generally design rates to cover these costs where rates include both fixed components (e.g., a monthly service charge) and a variable component (e.g., a charge per therm of gas consumed). Consumer bills are based on a consumer's gas consumption and the rate structure for their class of service. The wholesale price of gas to the utility affects the variable charge, but this wholesale price is generally marked up to help cover the full cost of service.

LIMITATIONS

This analysis relies on averages and typical examples in order to provide a variety of illustrative scenarios. For some of the analyses, such as on urban, suburban, and rural areas and on potential future capital costs, available data are limited. Often these data are published, but other times we rely on data from utilities that wish to remain anonymous. As additional data are collected, results may change somewhat. Also, these averages and scenarios do not represent all utilities and situations—each utility is different. Ultimately, each utility and their regulators will need to conduct utility-specific analyses.

Scenarios

In this study we looked at 19 scenarios:

1. Reference case
2. 25% of customers fully electrify
3. 50% of customers fully electrify
4. 75% of customers fully electrify
5. Electrification of 90% of the load
6. Electrification of 75% of the load
7. Gas pipe replacement – low
8. Gas pipe replacement – medium
9. Gas pipe replacement – high
10. Rural changes
11. Urban changes
12. Gas price lower
13. Gas price higher
14. Biogas instead of fossil gas

15. Census division variations
16. Combined scenario – medium
17. Combined scenario – high rural
18. Combined scenario – high urban
19. Energy efficiency by scenario

REFERENCE CASE

Our initial reference case of distribution utility costs comes from Davis and Hausman (2022). This in turn is based on AGA's 2020 survey on *Performance Benchmarks for Natural Gas Utilities*. The AGA survey includes data reported by individual gas utilities for the 2016–2018 period. The Haas study focused on the 2018 data. Table 1 summarizes these costs, which are also illustrated in figure 2 as the contribution of each of these costs to utility costs per customer.

Table 1. Average gas utility expenditures per customer in 2018

	2018	% of total
Cost of purchased gas	$312	44%
Capital-related expenditures		
Depreciation	63	9%
Return on net utility plant	105	15%
Operations-related expenditures		
Administrative	85	12%
Distribution, operations, and maintenance	66	9%
Account services	25	4%
Taxes	47	7%
Total expenditures	$703	100%

Note: These costs are in 2018$. These are averages for all customers including residential and some commercial. Source: Davis and Hausman (2022).

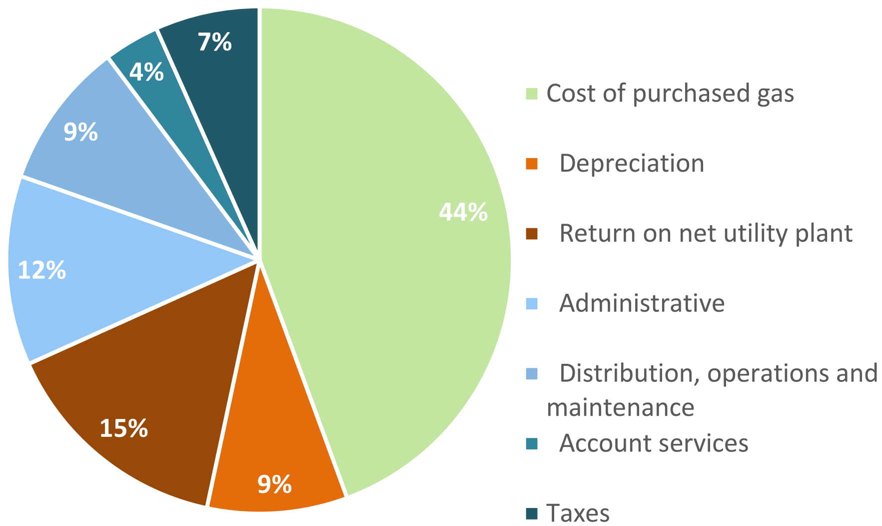

Figure 2. Distribution of 2018 gas utility costs per customer. Source: Data in table 1.

We then took these 2018 costs and first adjusted to estimate 2023 average costs and then to project 2040 reference case costs. For the 2023 adjustment, we applied an inflation factor based on the Federal Reserve Bank's Gross Domestic Product deflator (FRED 2023) to most of the costs, adding an allowance for anticipated inflation in 2023 (CBO 2023). Purchased gas costs are based on changes in wholesale gas costs (price at the Henry Hub) between mid-2018 (EIA 2023b) and projected costs for 2023 (EIA 2023e). And capital costs were adjusted to reflect changes in the average cost of capital to utilities in 2017 and early 2023 as defined and estimated by Damodaran (2017, 2023).

For our 2040 reference case projection, we assumed that most 2023 costs would remain unchanged in real terms. In other words, we assume that capital investments (including gas processing, storage, and distribution) increase with the rate of inflation but not more. We do this by conducting our analysis in 2023 dollars and thus an inflation adjustment is not needed. Later in this report we explore gas pipe replacement costs, which for some utilities are increasing much more than the rate of inflation. However, we do separately estimate the cost of purchased gas using the 2040 estimate of wholesale gas costs from the 2023 Annual Energy Outlook (EIA 2023a). This estimate suggests that, on average, wholesale gas prices will increase 21% in real terms from 2023–2040. We also assume that the 0.52% per year annual decline in natural gas consumption per household between 2015 and 2020 will continue each year going forward (EIA 2018, 2023d).[2] And we assume that costs to service customer accounts will decline by 1% per year, roughly in line with past trends.[3]

Applying these adjustments, in 2023, total expenditures per customer increase to $772 (2023$) and $839 in 2040 (also 2023$) absent any impacts of electrification or decarbonization. The 2040 reference case is 9% higher than the 2023 case in utility cost per customer, due to projected increases in the cost of natural gas relative to the early 2023 cost. The 2018 baseline, 2023 baseline, and 2040 reference case are illustrated and compared in figure 3.

[2] This decline in sales could have an impact on how fixed costs are recovered depending on how individual utilities structure their rates. We do not deal with this issue in the reference case but instead address it in the electrification scenarios.

[3] AGA data show customer account expense per therm declined more than 2%/year from 2008–2015 but declined more slowly in the 2017–2019 period (AGA 2021). Based on this we estimate a 1% per year decline from 2023–2040.

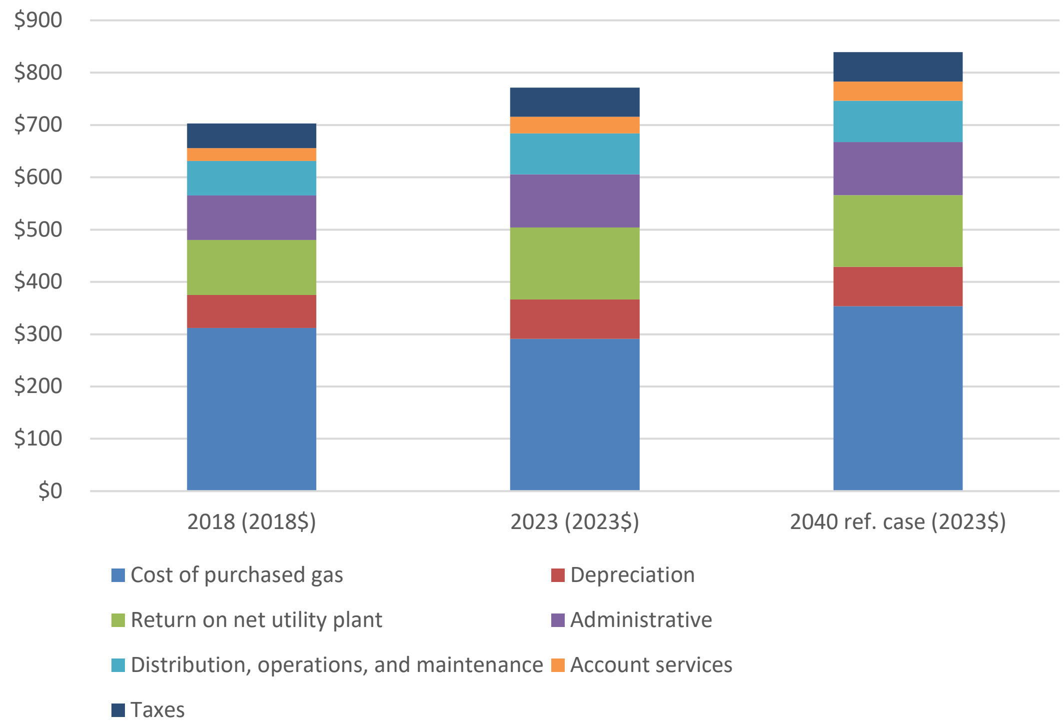

Figure 3. Average gas utility costs per customer in 2018, 2023, and 2040 reference case. 2023 is estimated; 2040 projected.

AMOUNT OF ELECTRIFICATION

Our first set of scenarios look at different degrees of electrification, examining what happens if 25%, 50%, or 75% of customers electrify and leave the gas system (we assume 100% electrification of each home or building; we address partial electrification in the next section). We consider electrification, both because many policy proposals seek to promote electrification, but also because multiple studies have found that electrifying space and water heating often has the lowest life-cycle cost among residential decarbonization options.

For example, Nadel and Fadali (2022) found that electrifying space and water heat often has the lowest life-cycle cost among residential decarbonization options, although in cold climates (greater than about 6,000 heating degree days (HDD)), a heat pump with a fuel backup (sometimes called a hybrid system) generally had the lowest life-cycle costs. A study on Rhode Island homes (approximately 5,500 HDD) found that for a typical single-family home, either ground-source or electric air-source heat pumps have lower annualized costs than using renewable natural gas (Murphy and Weiss 2020). A study for Puget Sound Energy, a utility in the Seattle area (approximately 4,500 HDDs), found that consumer total cost of ownership will generally be lower for electric heat pumps than hybrid systems (Olson et al. 2021). A study on Maryland (approximately 4,500 HDD) found the lowest total costs were for a policy scenario that combined heat pumps without a backup with policies to reduce energy demand (Maryland Commission on Climate Change 2021). And studies in Massachusetts (approximately 6,000 HDD) and Minnesota (approximately 7,500 HDD) generally found that hybrid systems will have the lowest total costs (E3 2022; GPI and CEE 2021).

For our electrification scenarios in the present study, we use estimates by Davis and Hausman (2022) on what percentage of different costs remain as customers leave the system. These estimates are provided in table 2.[4]

Table 2. Estimated portion of per customer costs no longer incurred when a customer leaves the gas distribution system

	Estimated portion of costs leaving with customer
Cost of purchased gas	100%
Capital-related expenditures	
Depreciation	0%
Return on net utility plant	0%
Operations-related expenditures	
Administrative	50%
Distribution, operations, and maintenance	10%
Account services	90%
Taxes	60%

Source: Davis and Hausman (2022)

Based on these estimates, the costs that are no longer incurred and the costs that are redistributed to other customers are illustrated in figure 4.[5] Of the total costs per customer, 57% are no longer incurred when a customer leaves the system but 43% need to be reallocated to the remaining customers.

[4] These are judgments on overall averages by Davis and Hausman; other analysts might make different judgments. Additionally, circumstances will vary from utility to utility. For example, one gas utility commented on a draft of this report that taxes would not decline as much as Davis and Hausman estimate since, in the utility's judgment, the local government would find a way to modify taxes so that tax revenue to the city does not decline by 60%.

[5] Redistributing costs to remaining customers is the most likely option, but there are other options such as charging exit fees to help recover fixed costs or using revenues from taxpayers to cover some of these costs.

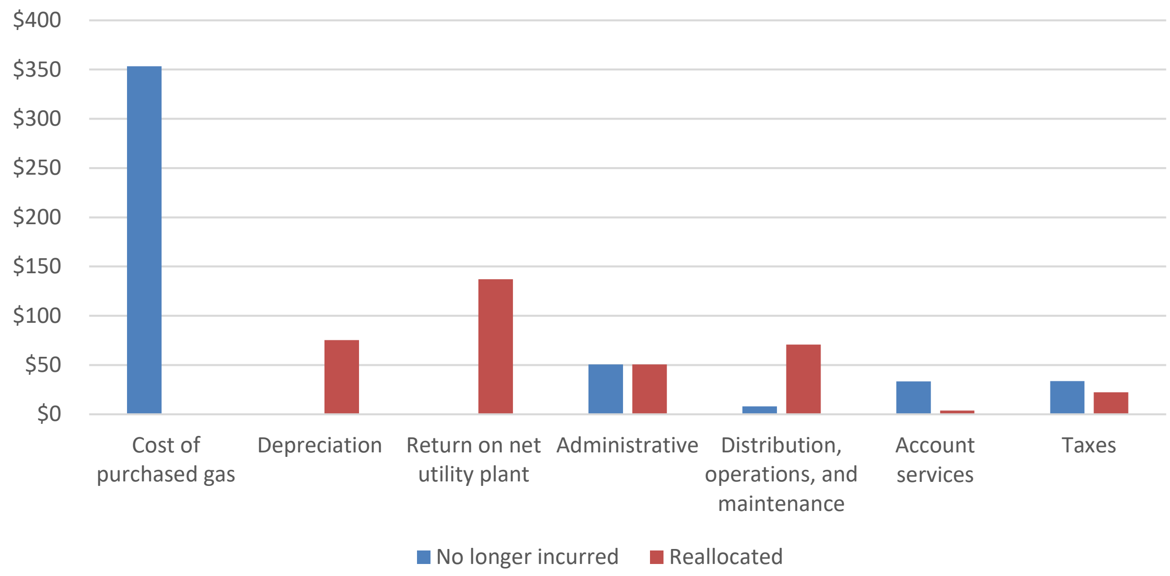

Figure 4. Costs per customer that are no longer incurred and that are reallocated to remaining customers (based on values in table 1)

Applying these allocation factors, in the 25% electrification scenario, costs to remaining gas customers increase by 21% in 2040. The cost increase to remaining customers is 43% in the 50% electrification scenario and 129% in the 75% electrification scenario. Total costs and allocation of these costs are illustrated in figure 5.

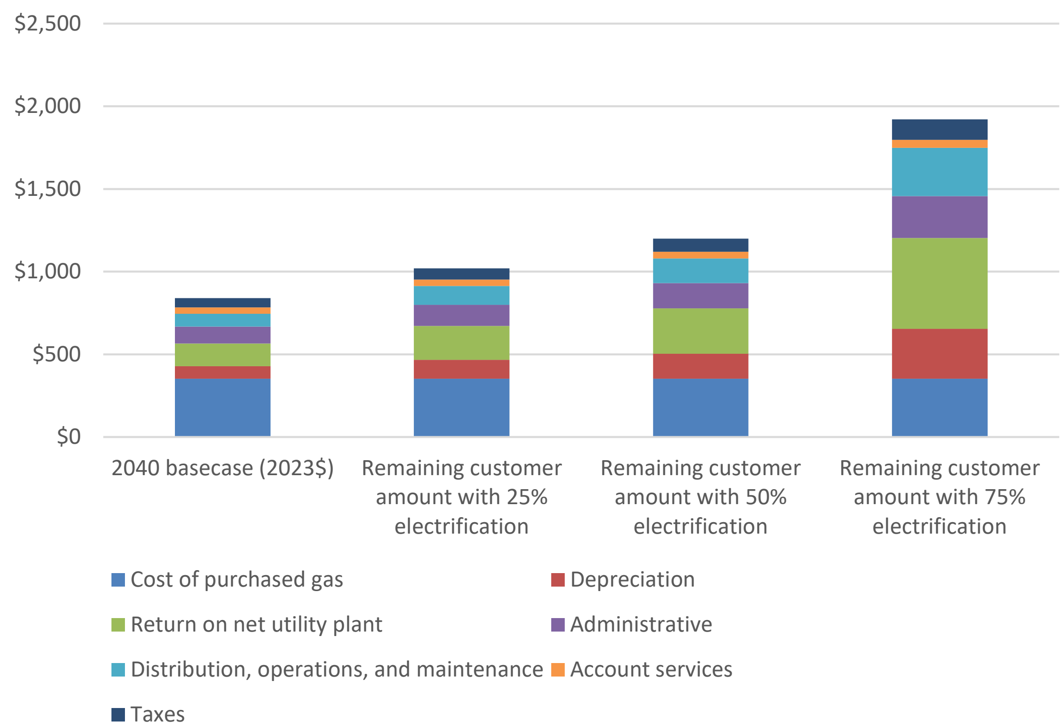

Figure 5. Utility costs per customer in the 2040 reference case as well as the various electrification cases

These estimates can be compared to the retrospective-based estimates by Davis and Hausman (2022), as summarized in figure 1 above. Reading off of the middle line in figure 1, Davis and Hausman estimate about a 25%, 60%, and 150% increase in costs to remaining customers if 25%, 50%, and 75% of customers leave the gas system. Thus, our estimates (21%, 43%, and 129%, respectively) appear to be similar to, but a little lower than, the Davis and Hausman estimates. The fact that they are similar is not surprising since our estimates build off of Davis and Hausman's data (our estimates differ a little due to the estimated changes in future years in gas costs and some other factors).[6]

A NOTE ABOUT EQUITY

A number of observers have expressed concerns that middle- and upper-income households will be much more likely to electrify, leaving lower income households on the gas system and stuck with higher costs for gas service (e.g., Walsh and Bloomberg 2023 and Harwood et al. 2021). While analyzing these impacts is beyond the scope of this paper, we do think it will be important to understand and address this problem. Financial resources will be needed to assist low- and moderate-income households to electrify. A few jurisdictions are attempting to do this (e.g., California, Massachusetts, and New York) but even in these jurisdictions available resources to date probably do not meet the need. This issue will need increasing attention in the future.

PARTIAL ELECTRIFICATION

An alternative to full electrification is partial electrification in which a heat pump is installed, but the gas heating system remains in place to provide backup heat when the temperature drops. We examine two partial electrification scenarios:

(1) Electrification of 90% of load, with gas retained only for cooking (gas stoves are popular with many consumers) and as backup when temperatures get very cold (e.g., below about 5^{o} F) and winter electricity peak demand is high and expensive to serve.

(2) Electrification of 75% of load, with heat pumps sized for cooling loads and supplemental heat needed about 25% of the time.[7]

[6] There is also a recent report by the Maryland Office of People's Counsel on the impacts of electrification and fuel decarbonization on gas rates (Maryland OPC 2022a). That report combines electrification with fuel decarbonization and we compare their results with ours in the discussion below on combined scenarios.

[7] This scenario is based on work by Harvey Michaels from the Massachusetts Institute of Technology (MIT) who is looking at loads in Massachusetts and finding that, increasingly, heat pumps will be installed when air conditioners need replacement. If the heat pump is sized for cooling loads, it will also serve about 75% of the

Partial electrification will result in lower cost impacts to remaining gas customers than full electrification, since many of the fixed gas distribution costs will continue to be passed onto partially electrified customers. However, for the customers that partially electrify, their costs could be higher as they are contributing toward fixed costs for both gas and electric service. The exact economics for a specific partially electrified customer will depend on local gas and electric rates.

For these scenarios we assume purchased gas costs for this customer decline by 90% or 75%, taxes decline by 50% (slightly less than the value shown in table 2 for full departure), and other costs remain the same. In the 90% electrification case, costs to serve these customers decline by 41%, leaving customers with 59% of their former gas bill, with capital, operations, and fixed costs now making up more than 90% of their bills. In the 75% electrification case, costs to serve these customers decline by 35%, leaving customers with 65% of their former gas bill, with capital, operations, and fixed costs now making up about 84% of their bills. These costs are shown in table 3. In addition to their gas bill, these customers will also pay for increased electricity use for the other 90% or 75% of their heating demand, with the result that the sum of their gas and electric bills is likely to go up unless they have a very favorable electric rate.[8] Estimating the electric bills of these customers is beyond the scope of this report but as electric loads grow, there will be a need for grid investments which will generally raise electric rates.[9]

heating load in Massachusetts (H. Michaels, lecturer in energy management innovation and principal investigator, Clean Heat Transition Project, Massachusetts Institute of Technology, April 24, 2023).

[8] It is possible that some electric utilities will offer favorable rates for heat pumps if they know there is a backup that can serve heating loads when outdoor temperatures get very low and winter electric demand peaks. For example, Harvey Michaels and Robert Nachtrieb from MIT have proposed such a rate for Massachusetts (Michaels and Nachtrieb 2022).

[9] The amount and cost of this investment will vary from utility to utility. Nadel and Fadali (2022) looked at several studies that examined these issues, finding studies that estimated that electrification would increase peak demand by 12% (for Vancouver, British Columbia), 21% (for Maryland), and 33% (for Minnesota, assuming use of hybrid systems. This higher demand will require increased investments in generation, transmission, and distribution, perhaps increasing rates by similar percentages. But much higher costs are also possible. For example, AGA (2018) estimates that electrification could increase U.S.-wide residential energy-related consumer costs by an average of 38–46%, with much of this increase driven by increased electric grid investments.

Table 3. Utility costs per customer in the reference case and for a customer that electrifies 75% or 90% of their load

	2040 reference case	% of total	Customer electrifies 75%	% of total	Customer electrifies 90%	% of total
Cost of purchased gas	$353	42%	$88	16%	$35	7%
Capital-related expenditures						
Depreciation	75	9%	75	14%	75	15%
Return on net utility plant	137	16%	137	25%	137	28%
Operations-related expenditures						
Administrative	101	12%	101	19%	101	21%
Distribution, operations, and maintenance	79	9%	79	14%	79	16%
Account services	37	4%	37	7%	37	8%
Taxes	56	7%	28	5%	28	6%
Total expenditures	$839	100%	$546	100%	$493	100%

GAS PIPE REPLACEMENT

Gas pipes are generally buried in the ground and will deteriorate over time, with the rate of deterioration depending on the type of pipe, local weather, soil conditions, and how old the pipes are. Common pipe types are black iron, galvanized steel, polyvinyl chloride (PVC), and high-density polyethylene (HDPE). Pipes must be repaired or replaced before safety problems occur, since gas leaks can lead to fires or explosions.

Some utilities, often in the West, have pipes that are only a few decades old (often due to recent growth as well as replacement of old pipes). Other utilities, often in the East, have many old pipes that will need to be repaired or replaced soon in order to reduce leaks and minimize potential safety problems. In some cases, pipe repair and replacement programs have been touted as climate programs because they reduce emissions of methane, a potent greenhouse gas (e.g., Massachusetts EOEEA 2022).[10]

Publicly available data on pipe replacement are very limited. We found four state and utility data sources or estimates and used them to guide our estimate of how future efforts to repair and replace pipes will affect utility costs. These estimates relate to both how much pipe might need to be replaced and to the cost of these replacements.

At the low end are data provided by Pacific Gas and Electric (PG&E) for a California Public Utility proceeding (PG&E 2022). In these data PG&E provide estimates of the miles of supply mains and distribution pipe that will be replaced over the 2023–2026 period. They estimate 0.3% of mains and distribution pipe will be replaced each year, and from this we extrapolate that 8.4% will be replaced over the 2023–2050 period. The PG&E data also include cost estimates for replacement per mile and data on capital costs. Pipe replacement is only a small portion of total gas utility capital costs. Future PG&E replacements will increase capital costs by about 2.9% per year, which is in line with expected future inflation (CBO 2023). Our estimate of 2040 capital costs (depreciation and return on equity as shown in table 2) is in real terms and effectively assumes capital costs increase at the same rate as inflation. Thus, our 2040 reference case assumes capital costs very similar to PG&E's plans.

At the medium level is a report prepared for the Maryland Office of People's Counsel (Maryland OPC 2022b) on a recent and large increase in gas utility investments to improve safety and reliability and to reduce methane leaks from pipes. This program is called the Strategic Infrastructure Development and Enhancement Plan (STRIDE). According to the OPC report, STRIDE spending over the 2022–2043 period will total $4.764 billion while traditional non-STRIDE gas utility capital investment will total $8.29 billion over this same period. Thus, adding STRIDE spending on top of traditional capital investment adds 57% to anticipated capital spending by Maryland gas utilities.

For our medium estimate we applied a 57% increase in gas utility capital-related spending (depreciation and return on net utility plant) to our 2040 reference case.[11] This increases total 2040 utility costs per customer by 13%.

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[10] On the other hand, a recent review of methane leaks in Massachusetts found no discernible reduction in leaks despite eight years of expensive pipe replacement efforts (Sargent et al. 2021). Another recent Massachusetts study suggests pipe repairs targeted at large leaks are a much more effective use of funds than extensive pipe replacement (Seavey 2021).

[11] This includes pipe replacement and other capital expenses. For the other estimates we cite, only replacement is specified and thus we assume that non-replacement capital costs will be the same, in real terms, as they are in 2023.

It should be noted that the Maryland report finds that these investments will increase gas bills for the largest Maryland gas utility by 56% (Maryland OPC 2022b). The Maryland percentage increase is higher than what we model because they show a significantly lower total customer bill than the utility cost per customer that we model. With our larger average bill, the impact of increased capital spending is diluted.

At a medium-high level is a report on Philadelphia's gas pipe replacement program that estimates it will cost the Philadelphia Gas Works $6–8 billion to replace half of its aging gas distribution pipes by 2058 (Seavey 2023). The study finds that pipe replacement costs have been increasing 8.5% per year from 2015 to 2021, even though the amount of pipeline replaced has remained relatively constant. If this continues through 2040, the percentage increase in capital costs would be on the order of triple the increase in capital costs as for Maryland STRIDE.[12]

Also at a high level, RMI (Gona and Henchen 2021) note that 26% of today's gas main system is over 50 years old and estimates that to replace all of these mains would require capital investments more than triple 2019 levels. For our high capital investment scenario we assume a tripling of capital costs, in line with RMI's estimate and also with projected costs for Massachusetts' Gas System Enhancement Program (GSEP) (Seavey 2022).[13] This high scenario may be applicable for areas with high needs to replace pipes for safety reasons. For this high scenario we also assume higher capital costs based on average capital costs per mile of pipeline over the past decade from New York City's two gas utilities. These capital costs have averaged $5.546 million per mile of new or replacement pipe (calculated by ACEEE based on data in Walsh and Bloomberg 2023). While this seems high, it is less than the $6.177 million average per mile estimated by Walsh and Bloomberg (2023) for the present.[14] In this high scenario utility costs per customer increase 106% above the reference

[12] The 8.5% per year includes inflation. If we assume a 5.5% real increase each year after inflation, over the 17 years to 2050 this totals a 148% increase (1.055^17), nearly triple the STRIDE increase. We also compared planned expenditures in Maryland ($4.764 billion) and Philadelphia (used midpoint of $7 billion) to the number of gas customers in these jurisdictions (500,000 in Philadelphia per the utility website) and 1.27 million in Maryland (EIA 2023c). The result is that planned pipe expenditures per customer are $14,000 in Philadelphia and $3,760 in Maryland, a ratio of 3.7 to one.

[13] Seavey estimates a total cost for this program of about $40 billion over the 2014–2039 period. This is more than a factor of six higher than the Maryland pipe replacement program discussed above. Since the Maryland program is projected to increase total capital investments by 0.47%, a program that costs more than six times more could triple capital costs.

[14] It is also less than pipe replacement costs recently proposed by Washington Gas, which serves the District of Columbia. They are proposing to spend $5–10 million per mile depending on the project, with an average cost just over $7 million per mile (Washington Gas 2022).

case. This high scenario is much more likely to occur in old urban areas where pipes are aging and construction costs are high.

Total costs and allocation of these costs for the capital cost scenarios are illustrated below in figure 6.

We also conducted an illustrative scenario in which instead of replacing a gas distribution line, a utility helps all customers to fully electrify, allowing it to decommission instead of replace a pipe that is no longer safe. Harwood et al. (2021), for example, recommend that such targeted geographic electrification may make sense. In this scenario, replacing a mile of distribution is avoided, but the utility (or someone else such as a government) helps pay for electrification and the remaining capital and administrative costs that are no longer paid by the electrifying customers. The math is shown in table 4 and results in savings to the utility of about $1,300 per customer on the one-mile distribution line if remaining capital and administrative costs are transferred to other customers, and about $940 per customer if these remaining costs are subtracted from the cost savings. This is just an illustration based on some representative costs; costs for specific projects could differ substantially. In particular, many pipe replacement projects are for old pipes in urban areas where pipe replacement costs are even higher, although electrification costs for multifamily buildings are often higher than for single-family homes (Nadel and Fadali 2022).

Table 4. Illustrative scenario of costs per customer of electrification in lieu of distribution pipe replacement

Item	Cost	Notes
Capital cost to replace one mile of gas distribution pipe	$3,206,737	Midpoint from PG&E 2022 (in urban areas this will be higher as discussed below)
Number of customers on a mile of distribution (suburban density)	67.6	From anonymous utility
Capital cost per customer	$47,452	
Utility payment to customer for electrification	$25,000	Estimated costs to install a heat pump, heat pump water heater, induction stove, and heat pump dryer assuming a bulk purchase. Includes electric service upgrades in some but not all houses.
Net utility capital cost savings	($22,452)	

Item	Cost	Notes
Annualized capital cost per customer saved by not replacing line	($1,301)	For a 30-year term at a 3% real interest rate[15] (we use 30 years per Walsh and Bloomberg 2023)[16]
Remaining capital and administrative costs when customer leaves system	$360	Derived from figure 4
Net cost to utility of electrification in lieu of pipe replacement	($941)	

URBAN/SUBURBAN/RURAL VARIATIONS

Gas distribution maintenance and capital costs can vary based on density of housing and other buildings. In urban areas, many homes and buildings are served per mile of pipe while rural areas have much longer pipe runs between buildings. On the other hand, construction costs will generally be higher in urban areas. We explore these issues in this section, seeking to estimate urban, suburban, and rural costs separately. The scenarios in this section do not include any electrification. In most jurisdictions, capital costs for urban, suburban, and rural areas are combined and all customers pay the same share of capital costs, regardless of where they are located. Still, this information can be useful as utilities and regulators consider which capital costs to incur in the future.

We find one source of publicly available data on how gas distribution costs might vary between urban, suburban, and rural areas. In a 2023 report on New York State, Walsh and Bloomberg (2023) identify capital costs and miles of new and replacement pipe by utility over the past decade, allowing us to calculate an average cost per mile of replacement pipe for each utility. Costs varied between $740,000 per mile for National Fuel Gas (serving much of Western New York) to $6.18 million for Con Edison (serving Manhattan and suburbs north of New York City). We grouped these data in three groups: primarily rural (average cost of $894,000 per mile), primarily suburban (average cost of $1.85 million per mile), and primarily

[15] The 3% real interest rate is based roughly on the difference between the January 2023 utility cost of capital (5.9% weighted average of equity and finance per Damodaran 2023) and the expected 2023 inflation rate (3.3% per CBO 2023).

[16] While utilities currently often use longer depreciation periods, we assume a 30-year accelerated depreciation as part of decarbonization efforts. If we were to use a 60-year depreciation instead, this figure would be negative $922 instead of the negative $1,301 we show.

urban (average cost of $5.55 million per mile).[17] Even within utilities these data are often not available, and many utilities do not classify customers by density.

We also obtained data from an anonymous Eastern utility that serves rural, suburban, and urban areas. They were able to provide data by town from which we could calculate length of gas main and distribution pipe per customer. We found that in rural areas there are 2.5 times more feet of pipe per customer than in suburban areas. And in urban areas, there are half the feet of pipe per customer than in suburban areas. We used these relative ratios for our analysis, assuming typical density in suburban areas, with rural costs adjusted for more feet per customer and urban costs for lower feet per customer.

For this portion of our analysis, we adjusted capital-related spending in our 2040 reference case to account for differences between urban, suburban, and rural areas in feet of pipe per customer and construction costs (the latter using the New York State data noted above). The result is an increase in capital-related costs per customer of 20% in rural areas relative to suburban areas. And in urban areas, capital-related costs are 50% higher than in suburban areas after accounting for differences in pipe per customer and construction costs. But since capital-related costs are only a portion of total costs, when other costs are also included, total costs per customer are 5% higher in rural areas than in suburban areas while total costs per customer are 14% higher in urban areas than in suburban areas. These total costs and allocation of these costs are illustrated in figure 6. The urban and rural estimates do not include any increased capital costs of the types discussed in the prior section. These figures are rough estimates; costs for particular urban and rural situations could vary substantially from these estimates.

[17] National Fuel Gas, Rochester Gas & Electric, and Niagara Mohawk are in the primarily rural category; NYSEG, Keyspan Long Island, Central Hudson, and Orange and Rockland in the primarily suburban category; and Con Ed and Keyspan New York in the primarily urban category.

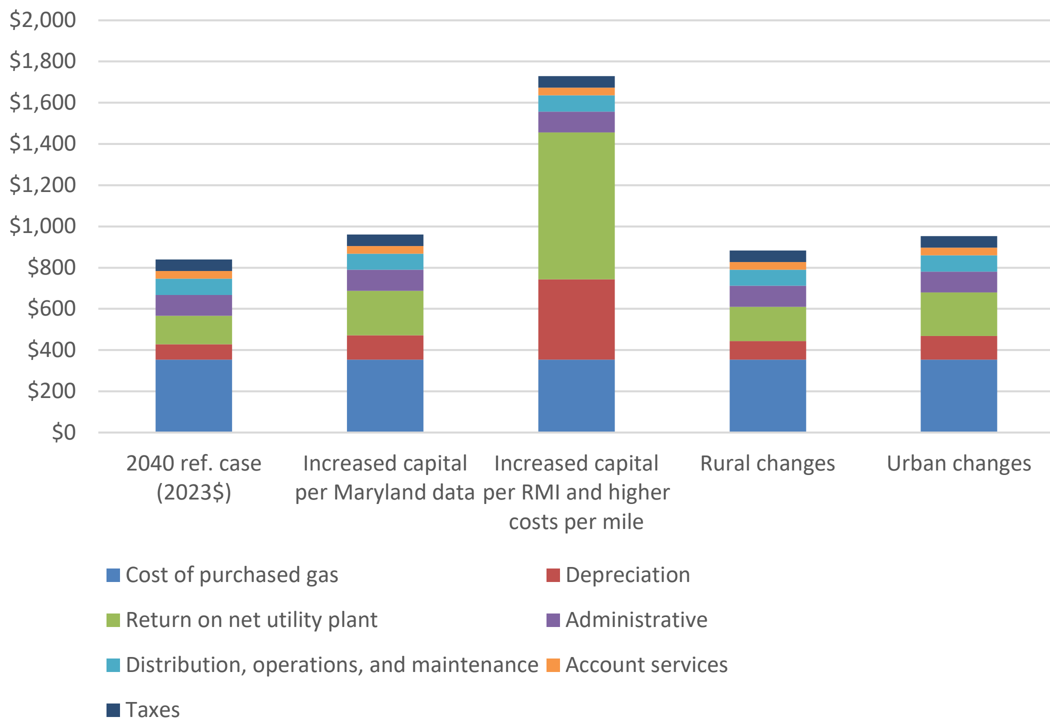

Figure 6. Utility costs per customer in the 2040 reference case as well as with medium and high capital costs and comparing rural and urban areas (suburuban areas are represented by the reference case). The rural and urban cases only include the same level of pipe replacement as in the refererence case.

VARIATIONS BY PRICE OF FUEL AND USE OF BIOGAS

Thus far in this report we have examined various aspects of gas distribution costs. In this section we consider several variations in the cost of purchased gas, in order to put distribution and gas purchase costs in context with each other. These scenarios do not include electrification beyond the limited electrification that is in the reference case.

Our 2040 reference case is based on wholesale gas prices for 2040 in EIA's Annual Energy Outlook (AEO) Reference Case. This predicts a 2040 wholesale gas price of $3.94 per million Btu (EIA 2023a),[18] which is somewhat higher than EIA's estimate of the average Henry Hub price in 2023 which is $3.02 (EIA 2023e). In this section we look at three variations on this wholesale price—a low estimate, a high estimate, and an estimate for use of biogas (which has the potential for low net greenhouse gas emissions). For our low and high estimates, we change the AEO Henry Hub price estimates for 2040 by plus and minus 25%. For biogas we use a 2022 report prepared for the New York State Energy Research and Development

[18] This is in 2022$. We add 1.65% to convert to mid-2023$, assuming 3.3% inflation for all of 2023 (CBO 2023). This results in an estimated 2023 price of $4.01 per million Btu.

Authority (NYSERDA) that looked at seven technical pathways for producing methane biogas. For each pathway they estimated the 2040 cost to produce methane. Individual pathways ranged from $11–35 per million Btu, with most of the pathways above $20 per million Btu (ICF 2022). We used the simple average of pathways, which was $25.61 per million Btu (the $11 pathway, which is landfill gas, is available only in limited quantities). It should be noted that the biogas scenario only includes the price of fuel and does not include any investments that some gas distribution systems might need to make to safely handle biogas or other alternative fuels.

A few other considerations are also worth mentioning. First, we use biogas for our low-carbon gas. Another option could be hydrogen produced with zero-emission electricity. Estimates are that hydrogen might be a little more expensive than biogas (New York City 2021) and also, to use pure hydrogen, burners and some pipelines and other gas infrastructure will need to be modified. It thus appears that biogas might be a little less expensive than hydrogen, and therefore we use this for our low-carbon gas scenario. We recognize that with further research and development and production at scale, it is possible that hydrogen will be cheaper. Second, there are presently federal tax credits for biogas and hydrogen but these expire in 2032 and therefore will not have a direct effect on the price of these fuels in 2040.

Results of these alternative gas cost scenarios are shown in figure 7. The high and low natural gas prices differ only a little from the reference case in utility cost per customer (–11% to +11% for 2040), while the biogas scenario is much more expensive, with fuel costs about six times higher than the reference case and total utility costs per customer 315% higher than the reference case (e.g., total costs are more than four times those of the reference case).[19] This last scenario is highly sensitive to the price of biogas. Even if somehow the price of biogas could be cut in half relative to the NYSERDA data, the result would still be an average utility cost of $1,741 per customer, more than doubling the reference case utility cost per customer.

[19] If costs double, they increase 100%. If they triple, they increase 200%. And if they quadruple, they increase 300%.

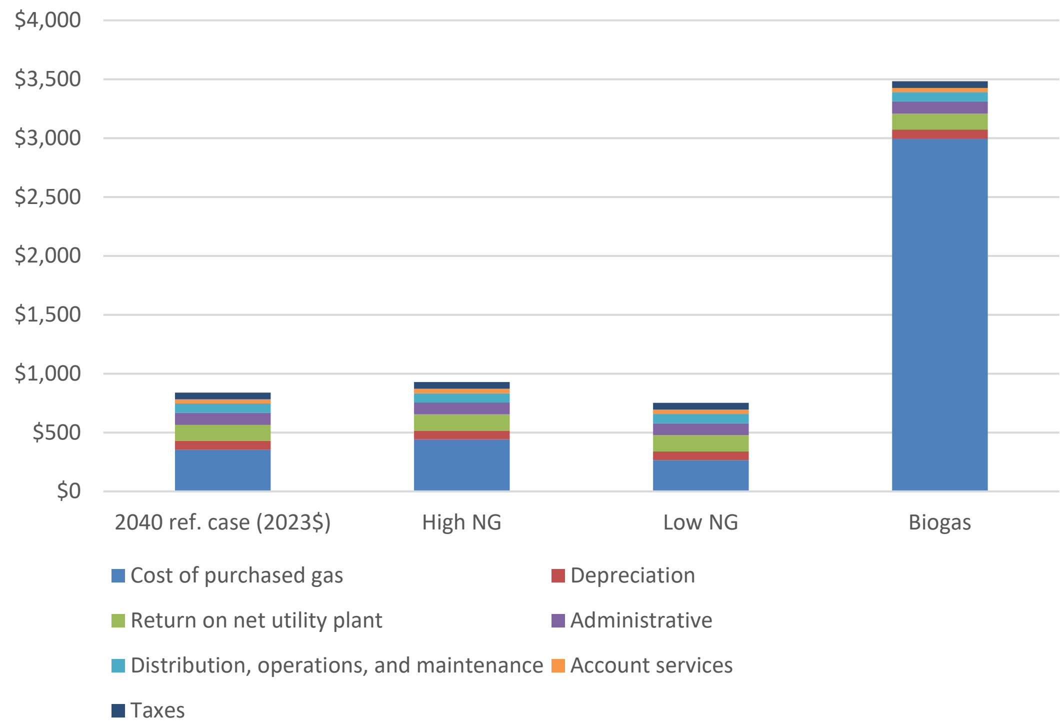

Figure 7. Utility costs per customer in the 2040 reference case as well as with alternative fuel costs from AEO and using biogas

VARIATIONS BY CENSUS DIVISION

Up to now, all of the scenarios are based on national average energy use. In this section we look at regional differences, adjusting for differences in average energy consumption (using the EIA's 2020 Residential Energy Consumption Survey (RECS) for regional variations in natural gas use per residential household) and energy prices (using EIA's 2023 Annual Energy Outlook). All of the costs except for purchased gas costs are assumed to be the same from region to region for the purposes of this exploratory analysis.[20] Results of these regional variations are provided in figure 8. We find that differences between regions are moderate, with the most expensive region (East North Central) having 16% higher utility costs per customer and the least expensive regions (East South Central and Pacific) having 13% lower utility costs per customer.[21] The modest differences between regions are due to

[20] Some of the other costs may also vary by region, but we do not have the data by region to look at these issues.

[21] East North Central includes Illinois, Indiana, Michigan, Ohio, and Wisconsin. East South Central includes Alabama, Kentucky, Mississippi, and Tennessee. Pacific includes Alaska, California, Hawaii, Oregon, and Washington. We use these regions because EIA uses them to report energy consumption and projected energy prices.

the fact that the majority of bills are fixed costs that do not vary between regions in our analysis.

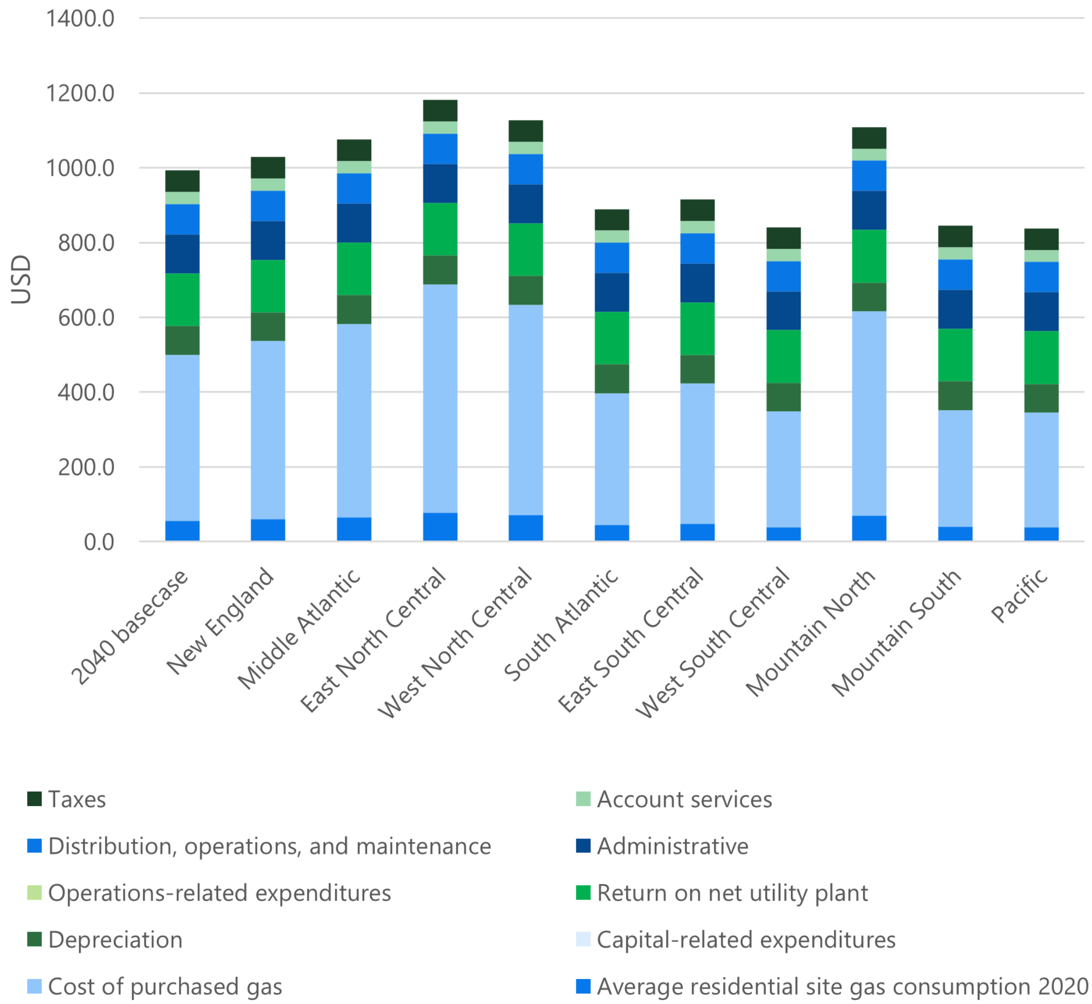

Figure 8. Estimates of average gas utility expenditures per customer in 2040 in the reference case and by Census Division. Notes: For this table we take the 2040 reference case from figure 3 and then adjust energy consumption for each region using average consumption per household in RECS (EIA 2023d) and average estimated energy prices by region in AEO (EIA 2023a).

COMBINED SCENARIOS

Up to this point, all of the scenarios examined have modified just one variable at a time. In this section we provide four plausible scenarios that make several modifications at once. We provide four illustrative scenarios out of dozens that could be done. We provide one low cost, one medium cost, and two high-cost scenarios, referring here to assumptions detailed in the previous sections.

Low

For our low scenario, we leave most of the variables at reference case levels. The one change we make is to assume electrification of 25% of homes. Thus, this scenario is the same as the 25% electrification scenario. In this scenario, total utility costs per customer increase 21% above the reference case, to $1,120 per customer.

Medium

Our medium scenario captures one of many possible middle points. We include 50% electrification, the increased capital costs (based on Maryland's data), and assume that half of the remaining customers use fossil gas and half use biogas. Average costs per customer climb to about $2,283, an increase of 172% relative to the reference case.

High

We prepared two high scenarios, one for rural areas and one for urban areas. For the high rural scenario we include biogas, rural area capital-related expenditures, and 75% electrification. For the high urban scenario we include biogas, urban area capital-related expenditures, higher capital costs per the RMI estimate, and 75% electrification. These scenarios result in utility costs per customer of nearly $4,000 for the high rural case and more than $5,000 for the high urban case, increases 373% and 544% relative to the reference case.

An even more extreme estimate of impacts is found in a report for the Maryland Office of People's Counsel on the combined impacts of electrification and fuel decarbonization on gas rates (Maryland OPC 2022a). That report found that:

> Replacing fossil gas with lower carbon alternatives causes the rates of the State's largest gas utility, Baltimore Gas & Electric, to increase two to three times 2021 levels by 2035 and seven to 11 times 2021 levels by 2050, with similar ranges of rate increases for Maryland's two other large gas utilities. Such rates are not sustainable. As rates increase to these levels, the resulting high bills will lead many customers—likely most all customers who have options—to leave the gas system, leaving behind customers without alternatives.

All four of these combined scenarios are illustrated in figure 9.

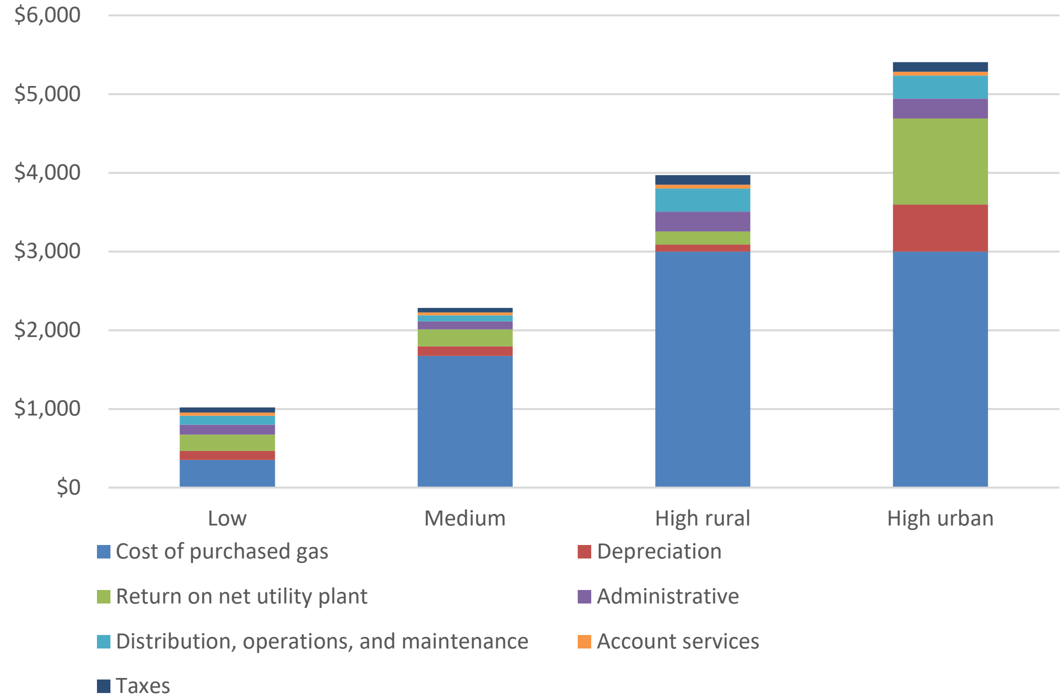

Figure 9. Utility costs per customer in 2040 in four combined scenarios as described in the text

IMPACT OF ENERGY EFFICIENCY ON SEVERAL OF THE SCENARIOS

For our final set of scenarios, we looked at how energy efficiency (weatherization and building envelope upgrades) might be able to reduce energy use and bills under several of the scenarios described above. We looked at how several of the decarbonization scenarios affect the economics of energy efficiency. This is a simple analysis from the customer perspective.[22] In all cases we assume 25% gas savings from a package of measures based on average savings from the Home Performance with ENERGY STAR® program. We use a cost of $5,000 per home, again based on Home Performance with ENERGY STAR but addressing only measures such as insulation and air and duct sealing that will reduce natural gas use (Home Performance also often employs additional measures to reduce electricity use, such as for lighting and appliances). While the $5,000 investment reduces gas use and costs, it also reduces electricity used for air-conditioning. These air-conditioning savings are not included in our analysis since we focus here only on gas. But as an indication, in 2015, the average U.S. home spent $265 on air-conditioning, and 25% savings on this air-conditioning

[22] An analysis from the utility perspective would be different and would include utility costs but exclude any funds paid by the customer toward the efficiency improvement.

would save the average household $66 per year (EIA 2018). Details on the costs and savings data we used come from Nadel and Fadali (2022). Since our analysis in this paper is based on annual costs, we assume the $5,000 efficiency package is financed with a loan, such as one a utility might offer through an on-bill financing program. We assume a 15-year term and an interest rate 3% above the inflation rate.[23]

Results of efficiency as part of decarbonization scenarios shows that the efficiency package we modeled will reduce consumer gas bills in some scenarios but not others. Essentially, the efficiency package pays in scenarios with high average gas bills (significantly higher than current costs), but not in the lower gas bill scenarios. Results are shown in table 5.

Table 5. Economics of an energy efficiency package applied to several of our scenarios

Annual costs and benefits	Reference case	Increased capital and pipe costs	50% leave	75% leave	Biogas	Combined medium
Cost per customer	$839	$1,729	$1,200	$1,920	$3,483	$2,283
Efficiency savings	210	432	300	480	871	571
Loan payments	(419)	(419)	(419)	(419)	(419)	(419)
Net	$(209)	$13	$(119)	61	$452	$152

Notes: Cost per participant is the total gas expenditures from the various scenarios described above. Efficiency savings assume 25% savings and loan payment is based on a $5,000 loan for 15 years at an interest rate 2% above the inflation rate.

Gas bill savings are achieved in the increased capital and pipe cost, the 75% of homes electrify, the biogas, and the medium combination scenarios but not in the reference case or the 50% of homes electrify scenarios. The efficiency savings are particularly large for the biogas case, so for homes that switch to biogas, pursuing a comprehensive energy efficiency retrofit will generally be important. In interpreting these results, please remember that air-conditioning energy use reductions are not included in the analysis.

Finally, we note that this analysis is all based on the gas use of an average home. For homes with above-average gas use, the efficiency package is more likely to save money than what we show here.

[23] The 3% real interest rate is discussed in footnote 3.

Implications for Utilities and for Policymakers

Of the various scenarios we examined, several stand out for their impact on utility costs per customer. We find that costs to remaining gas system customers will increase dramatically in the 75% electrification scenario, the high capital investment scenario for extensive gas pipe replacement, the biogas scenario, and the medium and high combination scenarios. The United States has committed to long-term decarbonization (Department of State and Executive Office of the President 2021), so policymakers need to figure out how best to manage gas system costs associated with decarbonization. Likewise, the United States is committed to gas system safety but the high costs of gas system replacement also need to be managed and reduced where possible. The high costs of the biogas scenario imply that widespread use of biogas is probably not a least-cost decarbonization strategy (not to mention the fact that biogas is likely to be in limited supply).[24] For a substantial majority of homes, electrification is likely to be a less expensive option on both an operating cost and a total life-cycle cost basis. In cold regions, some backup heat may be useful when temperatures get very cold (e.g., below 5° F) (Nadel and Fadali 2022); understanding its role requires evaluating both gas and electric costs together.

Assuming decarbonization, including widespread electrification and increased use of biofuels, it will be important to manage the cost impacts on customers who remain on the gas system, particularly low- and moderate-income customers. Our analysis finds that cost impacts on remaining customers are modest at 25% electrification, but become more substantial at electrification rates above 50%. Utilities and policymakers should begin planning for such a future, examining efficiency programs to reduce consumption and bills, rate structures, depreciation schedules, strategic targeted electrification and gas-line decommissioning where pipe replacement costs are high, and funding sources besides rates. Many of these options are discussed in the paragraphs below.

Regarding electrification, we note that this can take a number of forms. "Unmanaged" and "uncoordinated" house-by-house electrification will be the costliest. If electrification relies on strategic retirement of gas pipe plus zonal electrification (with air-source heat pumps or networked geothermal[25]), costs may be lower due to economies of scale and saved pipe replacement costs. Further analysis that incorporates system-specific topology could identify managed pathways for utilities in areas with decarbonization goals or where electrification is highly economical.

[24] Fuel availability is discussed by ICF (2019) and Borgeson (2020).

[25] Information about networked geothermal is summarized by HEET (2023).

RECOMMENDATIONS BY OTHER RESEARCHERS

In 2021, the Regulatory Assistance Project (RAP) prepared a report that looked at *Gas Utility Regulation for a Time of Transition* (Anderson, LeBel, and Dupuy 2021). The report recommended three key strategies:

1. Revitalize gas utility planning, including a robust and inclusive stakeholder process, creating layered system maps, developing several alternative scenarios, and creating a short-term action plan and a long-term transition plan.
2. Enhance energy efficiency and electrification programs including removing regulatory barriers to electrification, expanding and coordinating energy efficiency and electrification programs, evaluating and implementing non-pipeline alternatives for serving energy demand, and geographic targeting of whole-building electrification as part of a gas distribution network transition strategy.
3. Reform gas ratemaking.

In this last category, the RAP report makes several specific recommendations:

- Pay down rate base and lower the risk of rate impacts.
  - Require additional investment from new customers (e.g., new developments) 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 ratemaking improvements to deemphasize capital investments and incentivize customer objectives and public policy outcomes.

Likewise, RMI and National Grid recently convened a roundtable of leading gas utilities and nonprofit organizations to discuss ideas for managing gas system decarbonization. This roundtable developed a variety of recommendations (RMI and National Grid 2022), including some that might help to manage transition costs. The roundtable identified six strategies:

1. Improving gas infrastructure planning;
2. Designing decarbonization plans for customer and community benefit;

3. Creating new gas utility innovation programs and funding;
4. Evolving the gas utility business model;
5. Achieving a deeply efficient and flexible buildings sector; and
6. Establishing low-carbon heating and fuel standards.

Under the first category they include such strategies as considering alternatives to investing in new infrastructure (such as using energy efficiency and demand response to reduce the need for expanded infrastructure), modified depreciation timelines for gas infrastructure, different capital treatment for non-capital investments, securitization,[26] and geographic targeting of specific decarbonization and infrastructure solutions.

Under the fourth category they suggest modifying the regulatory framework to align with climate and equity goals and to incentivize and reward new utility business models and investments. A recent article by McKinsey & Company (2022) suggests examples of the latter can include gas utility investments in electrification (including community-level ground-source heat pumps) and systems to produce and distribute biofuels and hydrogen, particularly to serve end uses that are hard to electrify such as high-temperature industrial processes and backup heat for buildings in very cold climates.

McKinsey & Company (2022) also notes that "in some regions, the existing gas infrastructure may no longer justify the ongoing cost of safe and reliable maintenance or may be too expensive to upgrade for clean fuels. In such cases, communities and utilities can explore options for decommissioning safely and affordably while still meeting customer needs – for example through electrification, enhanced energy storage, and clean-fuel microgrids for resiliency or backup." They note that "decommissioning is more likely for distribution pipelines that serve primarily residential areas, as compared with transmission pipelines that serve generators and industrial customers." They suggest that "decommissioning will likely require stakeholder buy-in, regulatory direction, and rigorous planning and communication with customers." And they note that "customers whose appliances previously relied on gas will likely need ample warning, time, and resources to convert their appliances to electric power."

[26] Securitization is a process in which certain types of assets are pooled so that they can be repackaged into interest-bearing securities. The interest and principal payments from the assets are passed through to the purchasers of the securities. Securitization can reduce costs if there are dedicated revenues to pay off the securities so that investing in the securities is low risk. Securitization has been used by some states and utilities to cover the cost of closing coal-fired power plants or to cover extraordinary energy costs such as occurred in Texas and Oklahoma during 2021's winter storm Uri.

In addition, we note that laws in some states have "duty to serve" provisions under which gas companies are required to serve all customers who request service. There will often be a few customers on a line who will want to retain gas service, so decommissioning will not be an option unless duty to serve provisions are modified. Pending legislation in New York State, for example, makes such a change (Casey 2023).

Our analysis implies that initial places to consider decommissioning may be rural areas where costs per customer can be high, and areas with mature pipelines slated for replacement. Decommissioning these mature pipes instead of replacing them would avoid these costs, as shown by our illustrative analysis on electrification in lieu of gas pipe replacement. Urban areas often have older pipes that may be leak prone and need replacement for safety reasons, as is now being contemplated in Philadelphia (Seavey 2023).[27] Some of the issues associated with gas system decommissioning are discussed by Walsh and Bloomberg (2023) and by Henchen and Kroh (2020).

Further Research Needed

This report is an initial exploration of these issues. We mostly use average national data in illustrative scenarios. Further analysis is needed, particularly at the state and local level as situations will vary from place to place. We also note that more data are needed, such as on differences in costs between urban, suburban, and rural areas and on how much distribution pipe might need replacement in specific areas.

This report found that decarbonization will have substantial cost implications for gas distribution systems, particularly on covering gas distribution capital costs as many customers electrify. The even higher cost of decarbonized fuel scenarios implies that the more economical path to decarbonization for many or even most customers is electrification and not alternative fuels. More work is needed to explore ways to manage these gas system costs—sometimes labeled "stranded costs"—through better planning and new financial arrangements such as implementing accelerated depreciation and charging new customers more for the costs they put on gas systems. More work is also needed on potentially addressing some of these costs through securitization and other related strategies, and for considering policy frameworks for decommissioning portions of the gas distribution system where full electrification is less expensive than pipe replacement. As part of this work, the equity implications of decarbonization and decommissioning will need to be considered and addressed, as households with limited resources are the most likely to remain on gas systems as other customers electrify and leave the gas system.

[27] This said, not all old pipes are potential safety problems. Also, some pipes can be repaired instead of replaced. Given the high costs of replacement, replacement budgets should be targeted where most needed for customer safety and to reduce methane leaks.

Conclusions

Residential and commercial gas service will become significantly more expensive as states, cities, and utilities move to decarbonize their systems. Decarbonization will involve electrification and potentially some use of alternative fuels. Even without decarbonization, gas service will become much more expensive in areas needing extensive gas pipe replacement.

Electrification has been found by other studies to be the lowest-cost route to decarbonization for most U.S. homes (e.g., Nadel and Fadali 2022). As more homes are electrified and leave the gas system, fixed gas system costs will be reallocated to remaining customers. We looked at illustrative scenarios with 25%, 50%, and 75% electrification, finding that average utility costs per customer can increase 20–119%, varying with the scenario. And in scenarios combining some electrification with increased capital investment for pipeline replacement, average utility costs per customer can increase by more than a factor of four. Alternative fuels such as biogas could play a role in decarbonization, but these will be expensive. In our biogas scenario, average utility costs per customer increase by about a factor of four, suggesting building energy decarbonization would benefit more from strategic planning than from seeking an alternative to efficient electrification for most applications.[28]

Our analysis finds that the costs of maintaining the gas distribution system in urban areas with old gas pipes that will need replacement, and in rural areas, will generally be higher. If decarbonization and cost management spurs discussions on retirement of some portions of the gas distribution system, these may be the best places to start.

Comprehensive weatherization packages can help reduce energy use and bills. Weatherization packages will be particularly important for high cost of gas service scenarios such as those characterized by the use of biofuels, high electrification, and high pipe replacement.

Utilities and regulators should explore the best solutions for decarbonization in their regions. Long-term planning will be needed as will innovative financial and accounting structures to help manage costs. This and previous studies show that cost increases for remaining gas customers are modest in the early stages of electrification before increasing exponentially. This is likely to hold across geographic regions and urban/suburban/rural utilities, but specific strategies to manage these impacts will require tailoring to local conditions. It is important for policymakers and energy planners to be proactive in anticipating these effects

[28] Work by Nadel (2022) finds that about 90% of fuel use in the United States can be electrified, but alternative fuels will be needed for the remaining applications such as long-distance transportation (planes, trucks, ships, and trains), high-temperature industrial process heat, and backup heat for very cold days in cold climates.

to institute measures to mitigate them for all customers and avoid them for households that already carry a significant energy burden.

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Appendix: Data on the Scenarios

	2018	% of total	Inflation Multiplier	2023	% of total	2040 basecase (2023$)	% of total
Cost of purchased gas	$312	44%	NA	$ 291	38%	$ 353	42%
Capital-related expenditures							
Depreciation	63	9%	1.194	75	10%	75	9%
Return on net utility plant	105	15%	1.194	137	18%	137	16%
Operations-related expenditures							
Administrative	85	12%	1.194	101	13%	101	12%
Distribution, operations and maintenance	66	9%	1.194	79	10%	79	9%
Account services	25	4%	1.194	31	4%	37	4%
Taxes	47	7%	1.194	56	7%	56	7%
Total expenditures	$703	100%		$ 772	100%	$ 839	100%
Increase over 2023 base				0%		9%	

	Remaining customer amt w 25% electrificatn	% of total	Remaining customer amt w 50% electrificatn	% of total	Remaining customer amt w 75% electrificatn	% of total
Cost of purchased gas	$ 353	35%	$ 353	29%	$ 353	18%
Capital-related expenditures						
Depreciation	113	11%	150	13%	301	16%
Return on net utility plant	206	20%	274	23%	549	29%
Operations-related expenditures						
Administrative	127	12%	152	13%	254	13%
Distribution, operations and maintenance	114	11%	150	12%	292	15%
Account services	39	4%	41	3%	48	3%
Taxes	67	7%	79	7%	123	6%
Total expenditures	$ 1,020	100%	$ 1,200	100%	$ 1,920	100%
Increase over 2023 base	21%		43%		129%	

	Customer electrifies 75%	% of total	Customer electrifies 90%	% of total
Cost of purchased gas	$ 88	16%	$ 35	7%
Capital-related expenditures				
Depreciation	75	14%	75	15%
Return on net utility plant	137	25%	137	28%
Operations-related expenditures				
Administrative	101	19%	101	21%
Distribution, operations and maintenance	79	14%	79	16%
Account services	37	7%	37	8%
Taxes	28	5%	28	6%
Total expenditures	$ 546	100%	$ 493	100%
Increase over 2023 base	-35%		-41%	

	Increased capital per Maryland	% of total	Increased capital per RMI and higher costs/mile	% of total	Rural changes	% of total	Urban changes	% of total
Cost of purchased gas	$ 353	37%	$ 353	20%	$ 353	40%	$ 353	37%
Capital-related expenditures								
Depreciation	118	12%	390	23%	91	10%	115	12%
Return on net utility plant	216	22%	712	41%	166	19%	211	22%
Operations-related expenditures								
Administrative	101	11%	$ 101	6%	101	11%	101	11%
Distribution, operations and maintenance	79	8%	$ 79	5%	79	9%	79	8%
Account services	37	4%	$ 37	2%	37	4%	37	4%
Taxes	56	6%	$ 56	3%	56	6%	56	6%
Total expenditures	$ 961	100%	$ 1,729	100%	$ 884	100%	$ 953	100%
Increase over 2023 base	15%		106%		5%		14%	

	High NG	% of total	Low NG	% of total	Biogas	% of total	Avoided replacement at suburban density
Cost of purchased gas	$ 442	48%	$ 265	35%	$2,997	86%	-
Capital-related expenditures							
Depreciation	75	8%	75	10%	75	2%	75
Return on net utility plant	137	15%	137	18%	137	4%	137
							($1,301)
Operations-related expenditures							
Administrative	101	11%	101	14%	101	3%	51
Distribution, operations and maintenance	79	8%	79	10%	79	2%	71
Account services	37	4%	37	5%	37	1%	4
Taxes	56	6%	56	7%	56	2%	22
Total expenditures	$ 928	100%	$ 751	100%	$ 3,483	100%	$ (941)
Increase over 2023 base	11%		-11%		315%		

	Combination Scenarios							
	Low	% of total	Medium	% of total	High rural	% of total	High urban	% of total
Cost of purchased gas	$ 353	35%	$ 1,675	73%	$2,997	75%	$2,997	55%
Capital-related expenditures								
Depreciation	113	11%	118	5%	91	2%	599	11%
Return on net utility plant	206	20%	216	9%	166	4%	1,093	20%
Operations-related expenditures								
Administrative	127	12%	101	4%	254	6%	254	5%
Distribution, operations and maintenance	114	11%	79	3%	292	7%	292	5%
Account services	39	4%	37	2%	48	1%	48	1%
Taxes	67	7%	56	2%	123	3%	123	2%
Total expenditures	$ 1,020	100%	$ 2,283	100%	$ 3,971	100%	$ 5,406	100%
Increase over 2023 base	21%		172%		373%		544%	

(all figures in 2023$)	2040 referece case	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain North	Mountain South	Pacific
Average residential site gas consumption 2020	56.3	60.4	65.6	77.5	71.4	44.7	47.6	39.2	69.4	39.7	38.9
Cost of purchased gas	$ 353	$ 379	$ 412	$ 486	$ 448	$ 281	$ 299	$ 246	$ 436	$ 249	$ 244
Capital-related expenditures											
Depreciation	75	75	75	75	75	75	75	75	75	75	75
Return on net utility plant	137	137	137	137	137	137	137	137	137	137	137
Operations-related expenditures											
Administrative	101	101	101	101	101	101	101	101	101	101	101
Distribution, operations and maintenance	79	79	79	79	79	79	79	79	79	79	79
Account services	37	37	37	37	37	37	37	37	37	37	37
Taxes	56	56	56	56	56	56	56	56	56	56	56
Total expenditures	$ 839	$ 865	$ 898	$ 972	$ 934	$ 767	$ 785	$ 732	$ 922	$ 735	$ 730
Amount above or below base case	0%	3%	7%	16%	11%	-9%	-7%	-13%	10%	-12%	-13%

Notes:
* Average consumption per household from RECS (EIA 2023b)
* Cost of purchased gas adjusted up or down by region based on average consumption in that region relative to the U.S.