A MANAGED AND TIMELY TRANSITION LOWERS COST AND RISK

AN ANALYSIS OF OPTIONS FOR WASHINGTON'S GAS UTILITIES

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climate solutions

WE NEED TO FULLY* CUT EMISSIONS FROM GAS IN BUILDINGS BY 2050 TO MAINTAIN A STABLE CLIMATE AND TO MEET OUR GOALS.

WHAT ARE THE POTENTIAL IMPACTS ON GAS UTILITIES AND THEIR CUSTOMERS?

HOW CAN GAS UTILITIES PLAN TO REDUCE EMISSIONS WHILE PROTECTING CUSTOMERS?

*By at least 95% by 2050

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INTRODUCTION

Eliminating net emissions from Washington's building sector is a key component of meeting the state's objective to achieve net-zero emissions by 2050. In 2019, emissions from on-site fossil fuel combustion represented 28 percent of the state's greenhouse gas (GHG) emissions; half of these emissions are from fossil gas.[1] Furthermore, greenhouse gas emissions from the building sector is growing rapidly compared to that from other sources, at an increase of 51 percent in 2015 from 1990 levels.[2] Washington's 2021 State Energy Strategy (SES) provides a roadmap for meeting the state's GHG emission limits while improving quality of life and achieving a stronger, more just economy. The SES examined possible pathways to eliminate net building sector emissions and selected electrification as a key action for decarbonizing the building, transportation, and industrial sectors.[3] In buildings, electrification replaces fossil fuel combustion with efficient heat pump technology for both space and water heating using electricity generated from zero-emission sources, while simultaneously limiting electric grid impacts by upgrading inefficient electric resistance heating to efficient heat pumps.

Replacing combusting fossil fuels with electricity has a drastic effect on GHG emissions because Washington's electric grid is already one of the cleanest in the country and, under the 2019 Clean Energy Transformation Act (CETA), must reach 100% clean by 2045. Under the Climate Commitment Act (CCA), Washington also introduced a market-based program where greenhouse gas emissions are capped and the proceeds generated from auctions are invested in critical climate projects.[4] The CETA and CCA drive Washington's energy transition as large emitters are required to reduce their emissions to comply.

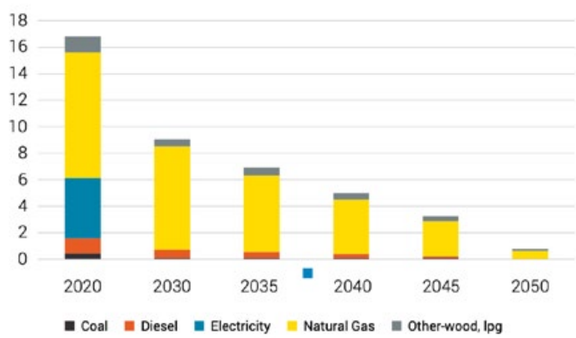
Washington's energy transition will dramatically reduce the amount of natural gas used in the state, and this will challenge the business model for the state's gas utilities. The SES identified the need to transition the gas industry as a key cross-cutting issue, stating that a "well-planned transition, with clear legislative and regulatory direction, is required to protect the interests of all concerned."[5] Climate Solutions asked Synapse Energy Economics (Synapse) to examine the potential impacts on gas utilities and their customers resulting from the state's pathway. This analysis includes what options the utilities and state policymakers have to mitigate the potential risks and challenges posed by the transition, using the state's largest electric and gas utility – Puget Sound Energy or PSE – as a model. We particularly focus on options to manage the reduction in size of the gas system, thereby managing the cost to operate the system, while accelerating depreciation to return invested capital to utility investors and avoid stranded costs as part of a strategy to keep gas rates affordable. We compare the impact of taking those steps immediately (2025) compared with delayed or unmanaged action, and we also evaluate the impact of combining electric and gas rates in a couple of ways to manage gas rate increases.

The remainder of this introduction provides background on the SES and the risks of an unmanaged energy transition to gas utilities and their customers. Section 2 details the potential changes to gas utility physical and financial approaches that could be used to mitigate some risks associated with the energy transition. Section 3 details the model Synapse used to examine the impact of the energy transition on PSE as an example of a dual-fuel Washington utility, and it presents results showing the impact of mitigating actions on revenue requirements and rates. Section 4 examines policy options to further mitigate the rate challenges identified in our modeling. We conclude with take-aways in Section 5. Appendix A provides greater detail about the utility financial model we use, and Appendix B provides a glossary of regulatory terms and other terms of art used in this report.

WASHINGTON'S STATE ENERGY STRATEGY

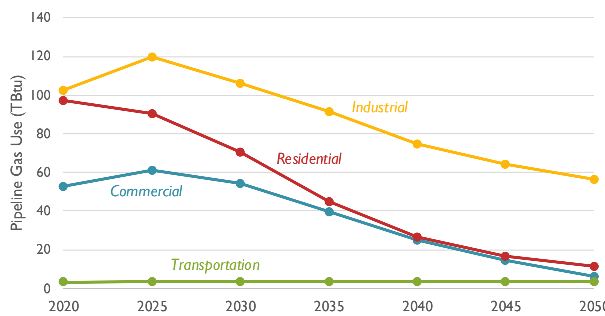
In addition to CETA and CCA, Washington's Legislature established ambitious economy-wide GHG emission reduction goals in 2020: 45 percent below 1990 levels by 2030, 70 percent reduction by 2040, and 95 percent reduction by 2050. Following the passage of this law, the Department of Commerce developed the State Energy Strategy which provides a roadmap for the transportation, buildings, electricity, and industrial sectors to meet these targets. The SES uses a "deep decarbonization" analysis to find the lowest cost pathway and identifies key policies and actions to make that pathway a reality. The SES prioritizes an electrification pathway for buildings. Figure 1, which reproduces Figure 18 from the SES, shows the building-sector emission reductions associated with implementing clean electricity, eliminating coal and diesel (heating oil) use in buildings, and dramatically reducing pipeline gas use.

Figure 1. SES Electrification scenario: building sector emissions by fuel type



Source: Washington State Department of Commerce. December 2020. Washington 2021 State Energy Strategy: Transitioning to an Equitable Clean Energy Future. *Page 68.*

Figure 2. Pipeline gas use in the Washington State Energy Strategy, Electrification scenario

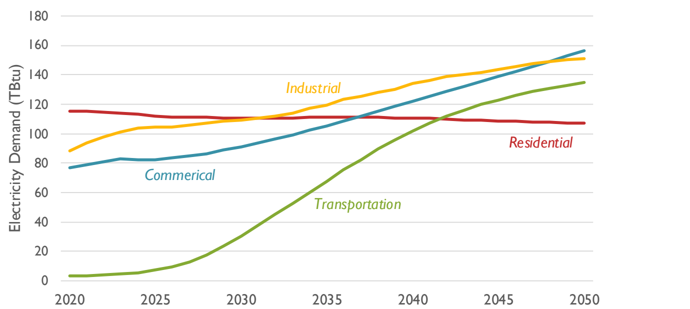


Source: Washington State Department of Commerce. December 2020. Washington 2021 State Energy Strategy, Appendix B: Data Accompanying Deep Modeling Technical Report (Excel). *Available at: https://www.commerce.wa.gov/wp-content/uploads/2020/12/Appendix-B.-Data-Accompanying-WA-SES-EER-DDP-Modeling-Report-12-11-2020.xlsx.*

We use the term pipeline gas to mean any gaseous fuel delivered using the existing natural gas distribution system. The SES envisions that about half of pipeline gas would come from biological sources by 2050 (commonly referred to as "renewable natural gas"), along with a small amount of hydrogen, and industrial sector gas use does not fall as dramatically as the use in buildings.[6] As a result, system-wide pipeline gas volumes described in the SES would not fall as precipitously as emissions. Figure 2 shows the pipeline gas trajectory from the SES. Gas distribution utility business models depend on volumetric sales of pipeline gas; even if the fuels transported are low-carbon fuels these changes in volume present energy transition challenges for gas utilities.

The SES also projects a noticeable increase in electricity consumption associated with electrification of residential and commercial buildings, transportation, and some industrial processes. Residential buildings do not show a net increase in electricity consumption because efficient heat pumps replace inefficient electric resistance heating. (Increases from electrification are more than offset by decreases from efficiency.) The greatest increase in electricity consumption comes from the transportation sector.

Figure 3. SES pathway modeled changes in annual electric energy demand



Source: Washington State Department of Commerce. December 2020. Washington 2021 State Energy Strategy, Appendix B: Data Accompanying Deep Modeling Technical Report (Excel). *Available at: https://www.commerce.wa.gov/wp-content/uploads/2020/12/Appendix-B.-Data-Accompanying-WA-SES-EER-DDP-Modeling-Report-12-11-2020.xlsx.*

Figure 3 shows the sectoral electricity demand trajectories in the Electrification scenario. In our analysis, we assumed transportation sector sales are split between residential ratepayers (for home electric vehicle, or EV, charging) and commercial rate classes (for workplace and public charging). While EV charging is a somewhat controllable load, the sheer amount of EV charging in the SES pathway means that some of the EV charging load is coincident with transmission and distribution peaks. We therefore assumed that EV charging causes a need for some investments in grid capacity to carry the increased load, which are then allocated to each customer class (alongside the grid investments driven by heating electrification and overall population growth).

RISKS TO GAS UTILITIES AND THEIR CUSTOMERS

While pipeline gas consumption will fall according to the state's decarbonization path, the revenue required to operate and maintain the gas system, as well as recover the capital invested in that system, will not fall unless the utility changes its physical and financial approach. If revenue requirements fall less quickly than sales, the per-unit costs to deliver gas will rise and thereby lead to rate increases.

Rising gas rates will have two effects. First, they will increase energy burden for customers who remain reliant on the gas system. Over time, these remaining gas customers will likely be lower-income customers who may already be energy burdened, as wealthier customers voluntarily upgrade to electric appliances or depart the gas system altogether. With fewer customers to pay for the revenue requirement, individual household rates and bills will increase and energy burden will fall even more heavily on those without the capital or control to electrify. Managing and mitigating this risk to low-income and disadvantaged customers should be an objective for policymakers.

Second, rising gas rates will make electrification more cost-effective for those customers who can afford to electrify. Quickly rising rates are more likely to trigger rapid and unmanageable departure from the gas system, exacerbating risks for both the remaining disadvantaged customers and utility investors.

Utility investors could also see increased risk from this transition unless the utility takes steps to mitigate the risk. Investor risk comes in the form of inability to recover the full revenue requirement over time. This could lead to investors earning a lower rate of return or even the utility failing to return invested capital to stock and bond holders. If rates rise to the point that they are driving customers to reduce consumption or depart the system, the utility may find that further rate increases do not actually increase revenue. At this point, the utility would face a real risk of stranded costs and associated losses to investors.

This report examines options for mitigating risks to both customers and gas utility investors through changes in physical and financial approach.

GAS UTILITY TRANSITION ACTIONS

Washington's investor-owned gas utilities are regulated by the Washington Utilities and Transportation Commission (UTC)[7] based on the principles of cost-of-service regulation. In this regulation structure, a utility justifies its cost of service to its regulator, and the regulator allows the utility to set rates at a level that will allow it the opportunity to recover its full cost of service. The cost of service includes the cost to operate and maintain the system (O&M); the recovery of capital invested (depreciation); property, income, and revenue taxes paid; interest on utility debt; and a fair return on capital to the utility's equity investors. Faced with the need to maintain affordable rates over both near and long terms, while recovering all invested capital, the utility and its regulators must strike an appropriate balance among these various cost drivers. By shifting when costs are incurred over the course of the decarbonization transition and by lowering overall costs where possible, the utility can improve equity outcomes while mitigating long-term rate increases and stranded cost risk.

We use the term "managed transition" to mean a process by which the utility manages the size of its system alongside its financial treatment of assets in order to minimize revenue requirements, rate increases, and inequitable outcomes. We assume a managed transition primarily consists of two actions: increasing depreciation rates and using a clustered (or neighborhood) approach to electrification so that utility assets can be retired sooner.

MITIGATING LONG-TERM COSTS THROUGH INCREASING DEPRECIATION RATES

The pipeline distribution system that brings gas to millions of Washington homes and businesses is constructed from materials that last for multiple decades, such as plastic and steel. However, the state's transition away from this fuel will shorten the useful lives of these assets. Once a gas meter, service line, or main, is no longer "used and useful" to deliver gas to customers, it is generally removed from the utility's plant in service and the company can no longer recover the cost of that asset or earn a return on the outstanding capital. The utility, therefore, has an incentive to align the depreciation lifetimes of its assets with their remaining useful lives.

Increasing depreciation rates to recover all utility capital over a shorter useful lifetime would result in near-term increases in the revenue requirement, and therefore rates. This approach would, however, lower rates and revenue requirement in the long term because there would be less net invested capital on which ratepayers would need to pay a return. Using this depreciation approach, low-income customers left on the gas system would face smaller

long-term rate increases. This also means that utility investors would face reduced risk of stranded costs.

Shifting depreciation costs toward the present could make sense for utility managers concerned about competition from electricity. This is because increasing depreciation rates while sales remain robust allows invested funds to be recovered with relatively smaller per-therm rate impacts, and thus relatively smaller impacts on competitiveness, than the same amount of money recovered later over fewer therms. Shifting costs to earlier in the transition should also improve equity outcomes because more of the costs of the existing gas system would be recovered from all current ratepayers, including those with the means to electrify soon, and fewer costs would be left to be recovered from the lower-income gas customers and renters who lack control over their heating systems or the means to electrify.

There are multiple approaches to accelerating depreciation. Examples include:

- Using straight-line depreciation with shorter useful lives for different classes of assets;
- Estimating the remaining useful life of each asset within asset classes (such as the number of meters with useful lives of 15 years, 16 years, 17 years, etc.) and using straight-line depreciation for each remaining life; and
- Utilization-based (or “units of production”) methods wherein the remaining volume of gas to be delivered by a given asset is estimated, and the asset is depreciated in proportion to the amount of gas delivered each year.

The modeling presented later in this report uses the second of these approaches (straight line depreciation to distinct retirement dates) for a managed transition.

REDUCING COSTS THROUGH CLUSTERED ELECTRIFICATION

The SES establishes a trajectory for the electrification of Washington’s building sector. However, the geographic distribution of those electrifying buildings can have a noticeable impact on how the gas utility manages and plans for the transition, and what costs are incurred. If electrification is scattered across the gas system, then all gas mains remain necessary for the provision of service, so they must be maintained and remain in the utility’s plant in service. However, if electrification takes place in a clustered (or neighborhood) manner, then mains in that area can be retired (to the extent that they are not necessary to serve customers in other nearby areas).

To take a simple example, if all the buildings on a cul-de-sac are electrified, then the dead-end gas main that serves that street can likely be retired. At a larger scale, if a neighborhood (or even small town) is served by only a few input points, then the whole network within that area can be retired when the last customer disconnects.

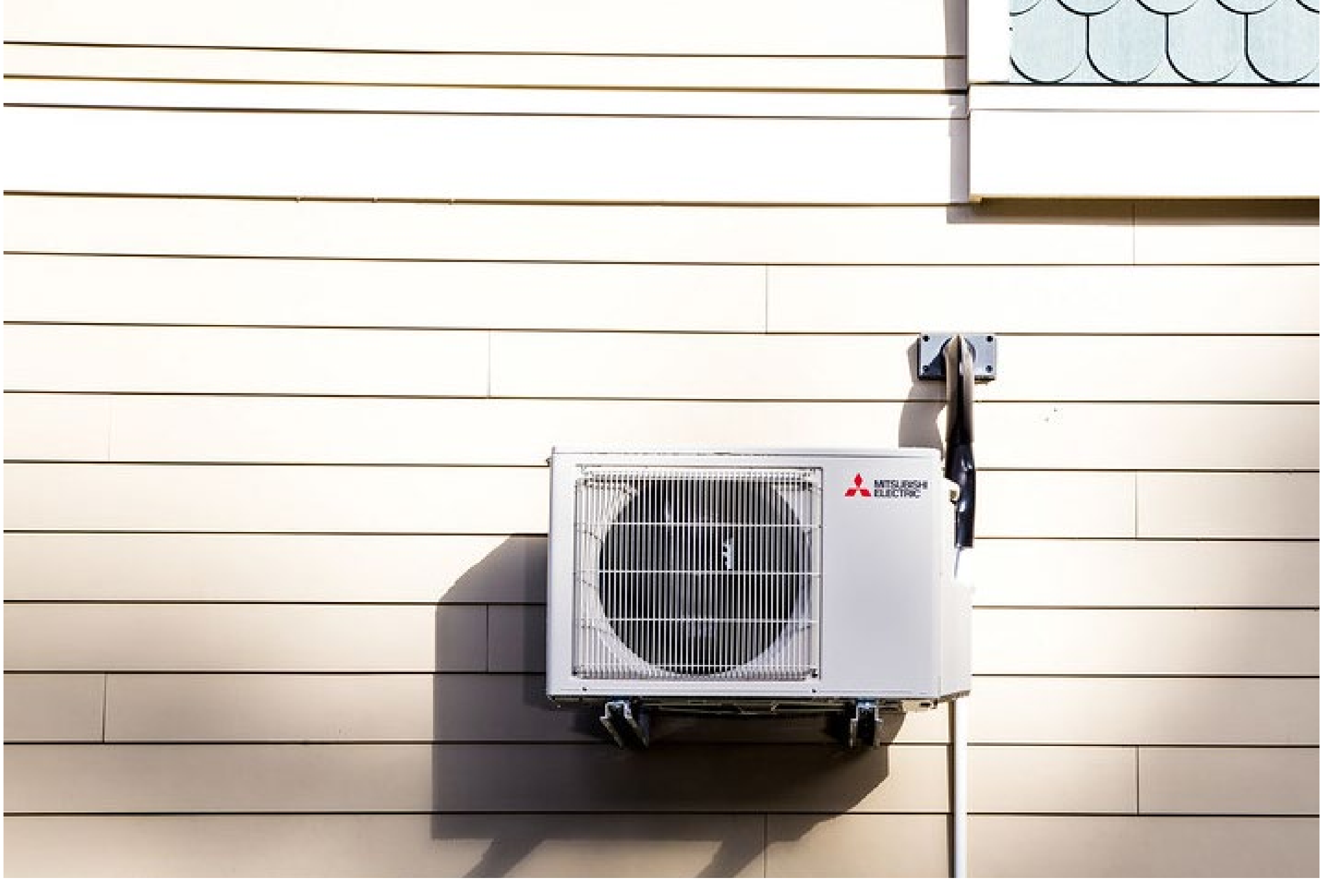
REDUCING COSTS THROUGH CLUSTERED ELECTRIFICATION

Clustered electrification reduces cost and rate pressure in two ways. First, it reduces plant in service and rate base; depreciation rates would need to be set at appropriate levels to ensure that these assets are fully recovered before they are retired to avoid stranded costs. Second, it reduces O&M costs. With fewer miles of pipe to maintain, there are fewer leaks to repair, fewer joints to inspect, and fewer compressor stations to operate and maintain. While customer service costs should fall roughly in proportion to the number of customers, and thus be largely independent of the geographic dispersion of electrification, retiring all the gas system in a given area can also reduce meter reading costs.

Adopting a clustered electrification approach would require more system planning and coordination than an unmanaged approach. This includes coordination with the electric utility to ensure that the electric grid is upgraded, if necessary, to serve additional load in the area. Selecting the areas to be targeted should incorporate information about the topology of the gas network (so that pipes can be retired without negatively impacting other customers), the age and condition of the gas assets (such as targeting assets that are otherwise scheduled for replacement), and the types of buildings and loads to be served (making sure they are suited for electrification with readily available and affordable technology). The selection should also involve coordination with municipalities on paving or other plans and coordination with the residents to be served. Neighborhood selection should also prioritize clustered electrification in low-income and disadvantaged communities to mitigate equity concerns, reach households who may be disproportionately energy burdened and impacted by long-term gas rate increases, and advance environmental justice by expanding access to clean, electric buildings.

Taking a clustered approach would likely require changes to legal standards around the obligation to serve. The regulator and gas utility would need to be able to tell customers that pipeline gas service is no longer available as a choice at their location, and that they can access other sources of energy such as electricity instead. Advance planning and notification would be essential so that building owners can be given time to adapt their building systems and avoid installing new gas equipment only to have to retire it before it has served a useful life. Communication and education with customers about the clean air and cost benefits of electricity will also be necessary.

Clustered disconnection of homes from the gas system could take multiple forms in order to cost-effectively accommodate building owner and resident needs. First, homes could fully and individually electrify using air-source or ground-source heat pumps, induction cooktops, and other efficient electric technology. Taking a clustered approach also raises the possibility of networked electric district heating systems, such as networked geothermal heat pumps. For buildings that have an end use that is not ready for electrification, it would likely be necessary to adapt the equipment to use propane and to switch to using this delivered fuel as part of a transition plan.



MODELING UTILITY TRANSITIONS 11

To explore the potential for gas utility actions to mitigate risks to customers and investors, Synapse modeled estimates of the potential future for PSE under the SES electrification pathway. PSE is Washington's largest electric and gas utility and we chose to model this utility because of its scale and reach in the state. We provide this analysis to illustrate the challenges and mitigation options facing gas utilities in Washington and not to provide results specific to PSE.

To conduct this modeling, Synapse used a customized version of its Strategic Transition Model (STM). The STM models the future of a gas utility by separating the capital and operating costs of the utility into two components: those costs which continue indefinitely throughout and after an energy transition ("indefinite"), and those which end during the energy transition ("retiring"). The model retires all assets from the "retiring" system before the last year modeled, and it sets depreciation rates to fully recover all invested capital with its allowed return. (In other words, the model cannot generate stranded costs.) In this case, the "retiring" system is the portion of the gas system that serves Washington's building sector, while the "indefinite" system serves the industrial sector. The retiring system consists primarily of "small pipe" mains, service lines, and gas meters.

The STM assumes the utility switches its depreciation and asset retirement approach in a year assigned by the user. That is, when that parameter is set to 2025, the utility in 2025 sets each asset on its system to retire in a known year (or be part of the indefinite system). Incremental changes accrue before this transition year, such as service line retirements not yet recognized through a change in asset depreciation rate, so the change in approach results in a spike in revenue requirement to recover the cost of these assets. The STM allows the user to mitigate this one-time cost by increasing depreciation rates for "retiring system" assets in advance of the transition year, and by spreading the spike in costs over subsequent years as a regulatory asset.[8,]

The STM models the impact on the residential, commercial, and industrial sectors separately, using allocators that are typical for utility cost-of-service studies (such as number of customers, sales, and peak gas demand). The STM assumes that large and high-pressure pipes in the existing system (including all gas transmission assets) are part of the indefinite system. Over time, the allocation of the costs associated with these assets are shifted to the industrial sector. Energy-transition-related costs (such as accelerated deprecation for retiring assets) are assigned only to the buildings sectors.

See the Appendix for more details regarding the STM method, assumptions, and approach.

EXTENDING THE STATE ENERGY STRATEGY

Washington's SES analysis extends through 2050. Because Washington's climate targets achieve a 95% reduction in GHG emissions, not 100%, some buildings remain on the gas system in 2050 in the selected Electrification pathway. However, the trend of gas use continues down approaching 2050, and sustaining full service to building customers after 2050 does not appear consistent with the pathway. Because we wanted to model different pathways to 100% decarbonization (not just 95%), we therefore developed extrapolations of the energy use for each sector, with pipeline gas use reaching zero in all residential and commercial buildings before 2065 (extending gas use to the end of the useful life of most appliances that remain in use in 2050). Figure 4 shows the extrapolation of the SES gas demand by sector.

Reductions in gas use do not necessarily result in customers departing the gas system. Some gas system costs relate to the number of customers, while others relate primarily to the extent of the gas system. We therefore required an estimate of the reduction in customers corresponding to the reduction in gas sales along the electrification pathway. We developed this estimate by assuming that per-customer gas use would decline by 2 percent per year, on average. We believe this assumption is reasonable because building shells will become more efficient over time (through weatherization and replacement of old buildings with newer, high-performance buildings) and building owners will electrify in stages (e.g., replacing a gas water heater with an electric heat pump water heater while retaining gas for heating until the heating system needs to be replaced). Figure 5 shows the resulting trajectories for the number of residential customers and the sales per residential customer. We do not assume that each household's gas use declines at the average rate: the average sales per customer reflects a blend of homes that retain full gas use (and thus use more than the average) with those that have partially electrified by replacing different pieces of equipment (e.g. water heaters, space heating systems, kitchen, and laundry appliances) and use less gas.

Figure 4. Assumed extension of SES pathway to 2065

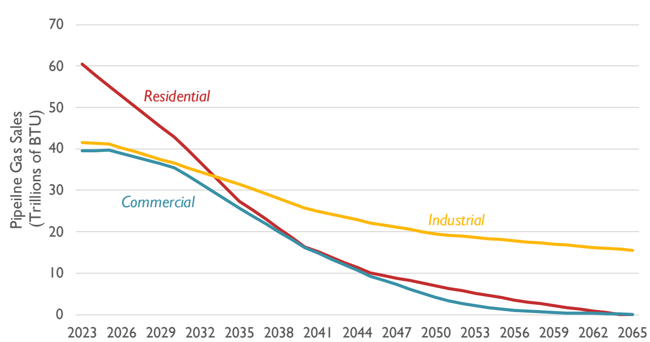
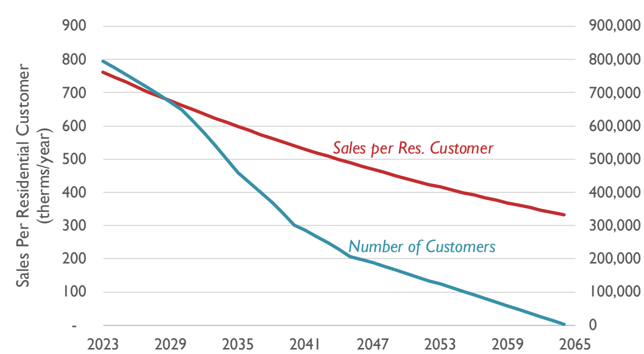


Figure 5. Residential sector customer count and average sales per customer



Note: There is no value for average sales in 2065 because there are no residential customers in that year.

SCENARIO DEFINITIONS

Synapse developed four scenarios in which to evaluate the impact of the SES energy transition on the gas utility. These scenarios have the same pipeline gas sales and customer counts by sector; they differ only in (a) the extent to which the electrifying customers are clustered, and (b) how the utility manages its finances. The four scenarios are:

MANAGED AND TIMELY TRANSITION (2025)

In this case, the utility implements a plan for clustered electrification and asset retirement beginning in 2025, and all assets are assigned their expected useful lives for depreciation as of 2025. An increasing fraction of electrification happens in the context of retiring gas mains, so the physical extent of the system falls as electrification proceeds.

DELAYED MANAGED TRANSITION (2030)

This case is similar to the Managed and Timely Transition, except that the utility begins to retire assets through clustered electrification in 2030 rather than 2025. The utility increases depreciation rates in the years leading up to 2030 in order to reflect its new understanding of useful lives, which partially mitigates the revenue requirement spike that would otherwise occur in 2030.

DELAYED MANAGED TRANSITION (2035)

This case is the same as the 2030 case, except that the clustered electrification and main retirements begin in 2035. The utility increases depreciation rates in the years leading up to 2035 in order to reflect its new understanding of useful lives, which partially mitigates the revenue requirement spike that would otherwise occur in 2035

UNMANAGED TRANSITION (2050)

In this case, electrification occurs at random across the utility's service territory. The utility gradually increases its depreciation rate to account for shifts in experienced average asset lives for service lines and meters. Mains continue to be used fully until all customers served by each main happen to have departed the system. Starting in 2050, the utility's financial accounts are updated to recognize the retirement and immediate depreciation of all meters, mains, and service lines that would otherwise be stranded. All remaining retiring assets are updated to short remaining lives (high depreciation rates) and complete the transition to full retirement by 2064.

In figures throughout this report, we simplify the scenario names to refer to the three Managed Transition scenarios by date ("2025", "2030", and "2035") and the Unmanaged Transition scenario as "Unmanaged."

Figure 6 shows the fraction of electrification that results in a proportional mains retirement in each scenario. For example, in the Managed and Timely Transition (2025) scenario, in 2040 about 40 percent of the buildings that fully electrify and leave the gas system do so as part of a clustered process that results in the retirement of the main pipe, meters, and service lines that serve that customer and their neighbors. Meters and service lines retire when their building electrifies, independent of the clustering, while mains only retire because of a clustered process. As electrification becomes more prevalent, the number of remaining customers in any given neighborhood falls, so the likelihood of a given building being the last on its main increases; this increases the fraction of customer departures that are effectively clustered and result in retirement of the gas main. Even the Unmanaged Transition (2050) scenario results in some asset retirement, because some streets fully electrify by chance; this fraction increases in the final years of the transition as the final customers electrify. All four scenarios reach 100 percent by 2065 so that the retiring system lives up to its name when it serves no more customers. Accordingly, the resulting miles of small distribution mains in the retiring system scale according to the trajectories shown in Figure 7.

Figure 6. Fraction of electrification that results in proportional main retirement, by scenario

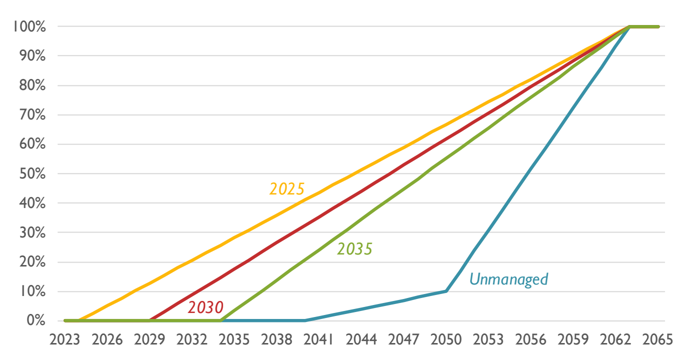
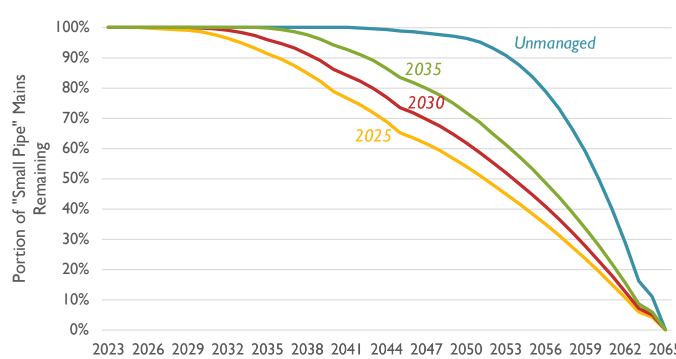


Figure 7. Portion of "small pipe" distribution main miles remaining, by scenario



SCENARIO RESULTS

Residential

Residential rates rise in real terms under all scenarios. This is expected because revenue requirements do not drop as fast as sales in any case. However, as shown in Figure 8, rates remain lowest and most stable over time in the Managed and Timely Transition (2025) case. Rates rise initially due to higher depreciation rates, but the use of the regulatory asset keeps them from rising too far, and they rise only gradually while the regulatory asset is in use.[9] For example, residential delivery rates rise only from $0.75 per therm in 2027 to $0.83 per therm in 2035. The Managed and Timely Transition (2025) case offers the lowest rates of any modeled scenario starting in 2031. Each year of delay in beginning a managed transition adds to the rates, because the utility continues to invest in its system before the transition begins, and there are fewer remaining years and therms over which to recover all investments. In each case, beginning to manage the transition (combined with the use of the regulatory asset) gently flattens the rate trajectory.

Figure 8. Residential delivery rate by scenario

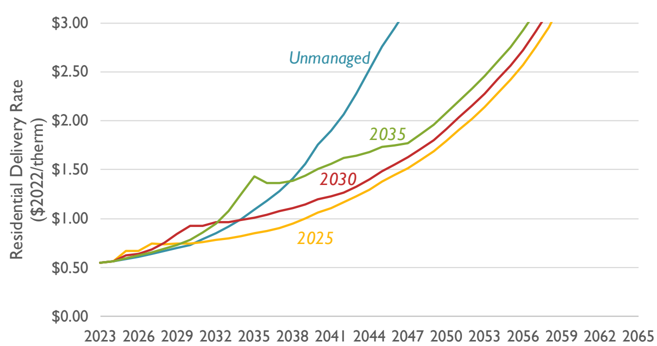
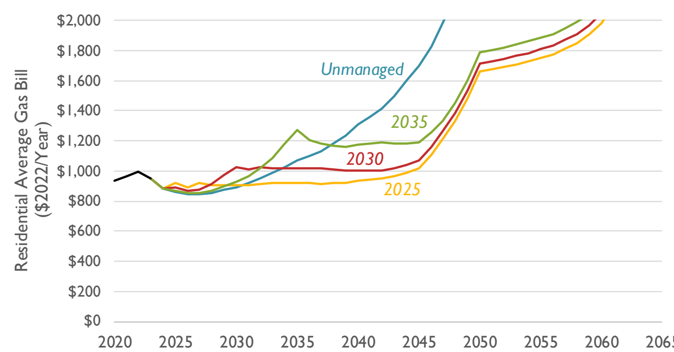


Figure 9. Residential average gas bills in each scenario through 2065



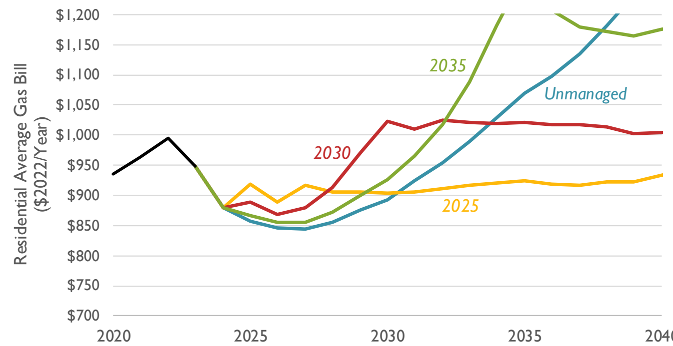
Residential bill impacts

To put these residential rates in household terms, we multiplied the rate by the average annual consumption per PSE residential gas customer to produce an average bill for gas service, shown in Figure 9. In addition to the delivery rate that is the focus of this report, this bill analysis addresses the cost of the gas commodity, including the incorporation of biogas in the years leading up to 2050 and beyond, and the cost of CCA compliance, which some utilities have started including in customer bills.[10] The rapid increase in bills seen in Figure 9 between 2045 and 2050 results from the SES assumption that biogas and hydrogen are blended into the pipeline gas system starting in 2045 in order to reduce remaining emissions on the way to 2050. The underlying, more gradual rising trajectory continues after 2050, with no further changes in the fuel blend.

While gas rates rise, average bills stay flatter (in real terms) because gas consumption per customer is falling (as shown in Figure 5). These results show the average bill effect, blended across many heterogenous buildings. A given household's gas use would not display the gradual decline in gas consumption shown in Figure 5; instead, its bills would rise with rates then take steps down as the owner weatherizes and/or electrifies the building's gas uses.

The Managed and Timely Transition (2025) case keeps average annual gas bills under $900 (in 2022$) into the 2040s, by which point fewer than one-third of customers remain on the gas system. Bills in the Unmanaged Transition (2050) case rise inversely to the number of customers, because the revenue requirement is not falling; average bills for this case pass $1,200 per year in 2044. Figure 10 zooms in on the bill projection to show the period before 2035. All four scenarios have average inflation-adjusted gas bills between $840 and $920 per year until 2029, and the Managed and Timely Transition (2025) case keeps average bills below $950 until 2042.

Figure 10. Residential average gas bills in each scenario through 2035

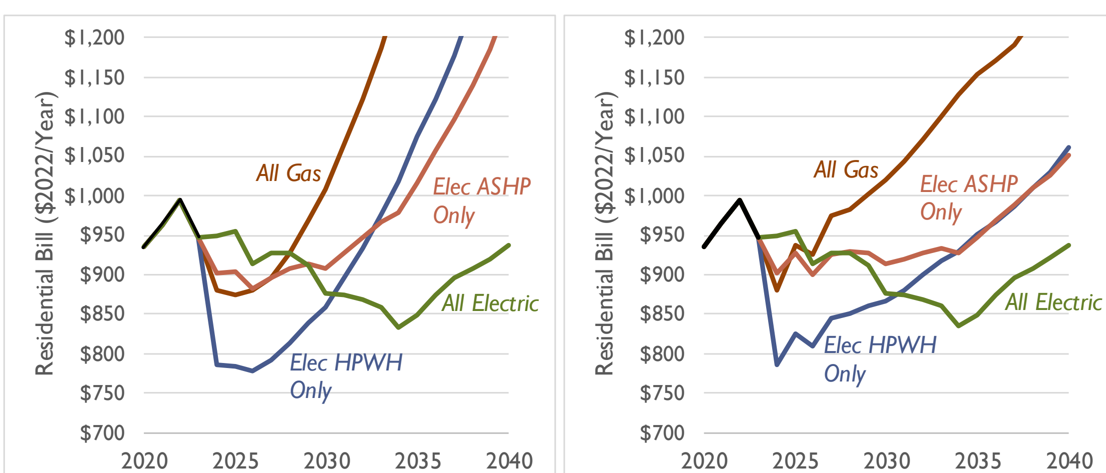


Different rate trajectories, resulting from different approaches to transition management, also have some impact on the relative cost-effectiveness of electrification. Figure 11 shows the average annual energy bills for end uses currently fueled by pipeline gas (namely space heating, water heating, and miscellaneous cooking/laundry uses), in the Unmanaged Transition (2050) and the Managed and Timely Transition (2025) scenarios. For both scenarios, Figure 11 shows the combined annual gas and electric bills for all gas, after electrifying water heating only with a heat pump water heater ("Elec HPWH Only"), after electrifying space heating only with an air source heat pump ("Elec ASHP Only"), and for all-electric. We draw two conclusions from these figures. First, the economics of electrification (particularly for water heating) are favorable compared to gas and in most cases become more favorable over time. Second, the extent of savings from electrification (e.g., the difference between the All Gas and All Electric bills) grows more rapidly in the Unmanaged Transition (2050) case, due to the higher costs of investment in unnecessary gas infrastructure. Managing gas transition costs reduces the risk of rapid and unmanaged customer departure from the gas system driven by rapidly growing energy cost differentials. Rapid and unmanaged customer departure is not a desirable outcome due to the risk of unsustainable escalation in bills for low-income households and renters, and the risk that the gas utility may not have sufficient revenue to maintain system safety and reliability.

Commercial

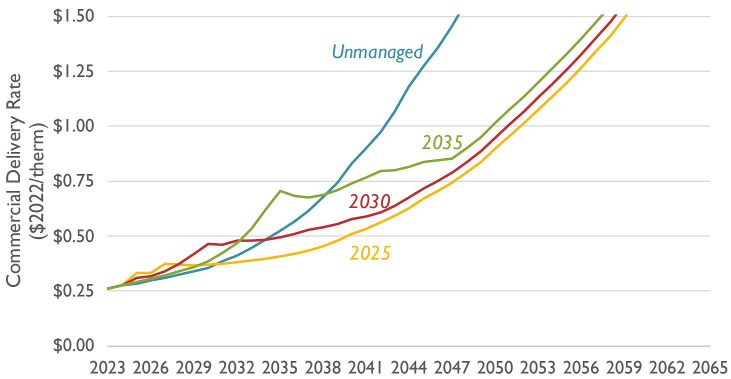
Commercial sector delivery rates show a similar pattern to residential delivery rates, although they remain lower

Unmanaged Transition (2050) **Managed and Timely Transition (2025)**



due to greater sales per customer, as shown in Figure 12. As with the residential sector, the Managed and Timely Transition (2025) case has the lowest rates by the very early 2030s. The Unmanaged Transition (2050) case has the highest rates after about 2038 and approaches twice the rates of any of the other cases by 2050.

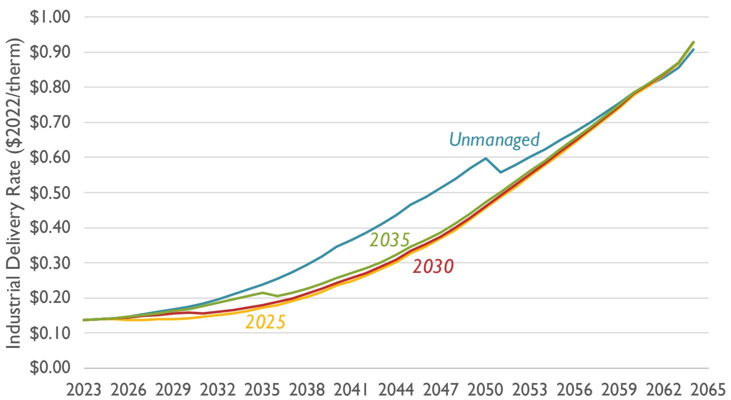
Figure 12. Commercial delivery rate by scenario



Industrial

Industrial customers are not assigned the costs of the retiring system and its high depreciation rates, because they use only the large pipes of the indefinite system (which is not subject to accelerated depreciation). This keeps industrial delivery rates lower and smoother than the other classes, as shown in Figure 13. Industrial rates do rise, however, as these customers are assigned a growing fraction of the gas transmission and "large pipe" portions of the gas distribution system, which are retained as part of the indefinite system to serve these customers, and industrial sales volumes gradually fall. While industrial customers do not see a strong relationship between how the "small pipe" system is managed and their rates, the Unmanaged Transition (2050) case does have somewhat higher industrial rates than the managed cases as a result of the greater utility overhead costs associated with maintaining a larger system.

Figure 13. Industrial delivery rate by scenario



Notes: The kink in the rate trajectory when the utility begins to manage its system is an artifact of the allocation of utility costs and would likely be smoothed over in practical ratemaking.

TOTAL GAS DELIVERY SYSTEM COSTS

Figure 14 shows our estimates of the utility's annual revenue requirements for gas delivery service in each of the four cases. While the Managed and Timely Transition (2025) case shows the highest revenue requirement in the near term, it becomes the lowest cost case by 2031, and remains the lowest cost case throughout the remainder of the study period. While it would be possible to make more extensive use of regulatory assets to shift more of the initial increase in revenue requirement past 2030 or 2040, after the revenue requirement starts to fall, this would increase rates substantially in those middle and later years due to the reductions in sales. Those increases would fall to a greater extent on low-income customers and renters, who are more likely to still be connected to the gas system at that point.

The present value of the utility's revenue requirement shows a clear progression of increasing cost associated with delay in adopting a managed transition, as shown in Table 1. We have provided the present value of the utility's revenue requirements at two discount rates: 2 percent real, which is a commonly accepted societal discount rate,[11] and 7.2 percent nominal (5.1 percent real), which is PSE's after-tax weighted average cost of capital. Table 1 shows that each year of delay between 2025 and 2030 in adopting a managed transition has a present value cost to PSE's ratepayers of about $100 to $160 million (depending on choice of discount rate).

Figure 14. Illustrative PSE annual revenue requirement for gas delivery service, by scenario

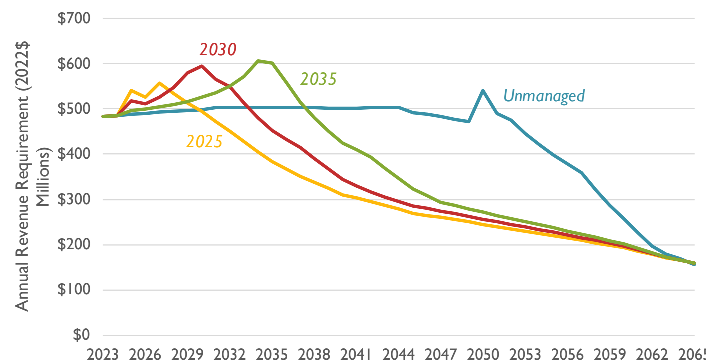


Figure 15. PSE gas delivery revenue requirement in the Managed and Timely Transition (2025) case, broken out by revenue purpose

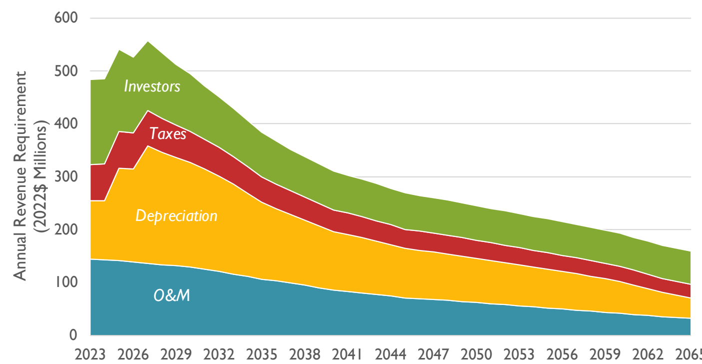


Figure 15 shows the breakdown of PSE's projected revenue requirement in the Managed and Timely Transition (2025) case, by type of cost. O&M costs fall steadily, driven by the number of customers and the smaller gas system. Depreciation costs rise with the start of the managed transition, then fall over time as assets retire. Taxes and investor returns (labeled as "Investors", which includes interest on debt as well as equity returns) fall during the initial period of high depreciation, then stabilize as the utility's indefinite system (serving industrial customers) becomes the major portion of the company's rate base. While the company becomes smaller over the study period, PSE's gas utility remains a profitable entity throughout, returning its expected returns to its investors. It is also worth noting that PSE has an electric business and, in areas where PSE serves both electric and gas customers, the company will retain departing gas customers when they switch to electricity.

Table 1. Present value of future PSE gas delivery revenue requirement, by scenario

	Present value, in millions of 2022$	
Scenario	**2% real discount rate**	**7.2% discount rate (5.1% real)**
Managed and Timely Transition (2025)	$10,021	$6,811
Managed Transition (2030)	$10,807	$7,322
Managed Transition (2035)	$11,548	$7,715
Unmanaged Transition (2050)	$13,132	$8,293

POLICY EVALUATION

The STM analysis presented above demonstrates the value of Washington's gas utilities changing their physical and financial approach earlier rather than later in the building decarbonization process. The specific approach that we modeled here is unlikely to be the exact pathway that works for Washington, but the state will likely use similar tools. Key policy levers to enable a planned physical and financial approach, while keeping customer rates and bills as affordable as possible, include changes to depreciation practices and striving to align a declining revenue requirement with falling gas sales.

Working within the gas utility alone, the primary ways to reduce revenue requirement are to reduce rate base (which happens naturally with increased depreciation rates) and to reduce the physical extent of the system to operate and maintain (such as through the clustered electrification approach described and modeled above). Additional policy options that would have the effect of reducing the gas revenue requirement and potentially mitigating the rapid and large rate increases as 2050 approaches would be to either raise revenue for the gas system from another source, such as electric customers, or transfer some costs from the future, smaller customer base to the current, robust customer base. We discuss the potential for these approaches in the following two sections.

SHARE REVENUE FROM ELECTRIC UTILITY

One potential approach to mitigating gas utility rate impacts could be to shift costs from gas ratepayers to others. In the case of dual-fuel utilities, such as PSE, one option would be to shift portions of the cost of service that are collected from gas customers today to be collected in whole or in part from electric customers. For example, if the gas and electric portions of the company have a single rate base, the investors' recovery of and on that rate base could be allocated to the electric or gas customers in a different ratio than the physical assets, as a matter of policy.

This approach could be acceptable from an equity standpoint provided that all electric and gas utilities are undergoing similar transformations and the costs of the revenue sharing are apportioned to the relevant electric utilities. This would result, broadly speaking, in the same people paying for the sunk cost of the gas system, just on a different bill. Some adjustment may be required to avoid transferring gas system costs to the electric bills of customers otherwise served by delivered fuels. As shown below, electrification tends to reduce electric bills, thereby benefitting all electric ratepayers.

We modeled this kind of cost shift by measuring the impact of shifting portions of PSE's gas revenue requirement from gas rates to electric rates. We have not accounted for the geographic equity concerns detailed in the preceding paragraph—for simplicity we are assuming full overlap between PSE's electric and gas customers. We evaluated three cases that strive to limit gas delivery rates to no greater than double today's rates (in real terms), shifting different types of revenue to electric rates in order to do so:

1. Recover investor return and taxes on gas assets from electric rates. ("Net Income")

2. In addition to the return on capital, shift depreciation (return of capital) from gas rates to electric rates. ("Depreciation")

3. Shift all revenue required to meet the modeled gas rate cap. ("All shift")

Figure 16 shows the resulting residential gas delivery rate trajectories in the Managed and Timely Transition (2025) case, alongside the no-shift case previously shown. While approaches 1 and 2 reduce the increase in the gas rate, they do not mitigate the final spike in gas rates. This is because system O&M costs remain, and the per-unit rate still rises as residential sales fall toward zero. Approach number 3 defines this spike out of existence, at the cost of transferring more costs to electric rates. If the gas rate limit were lower, the shift to electric ratepayers would begin earlier, and more revenue requirement would be shifted from gas to electric ratepayers; and vice versa for a higher gas rate limit.

Figure 17 shows the same three approaches, along with the no-shift case, for electric rates. Note that electric delivery rates fall noticeably during the 2020s and 2030s due to increased volume of sales relative to the electric system capital required to serve that load. (This is essentially the inverse of the process happening to gas rates.) In this case we see that electric delivery rates would need to increase by up to about 0.25 ¢/kWh in the 2040s and 2050s to provide the revenue required to offset gas rate increases. For the average all-electric residential household in 2050, 0.25 ¢/kWh rate impact to pay for the gas rate shift would be about $30 per year (in today's dollars). Electric delivery rates also rise to a value just above today's level after the mid 2030s even in the no-shift case, due to the accumulating capital investments to serve peak loads resulting from the combination of building and transportation electrification.

Figure 16. Gas delivery rate in the Managed and Timely Transition (2025) scenario, showing the reductions resulting from shifting different portions of the gas revenue requirement to the electric utility

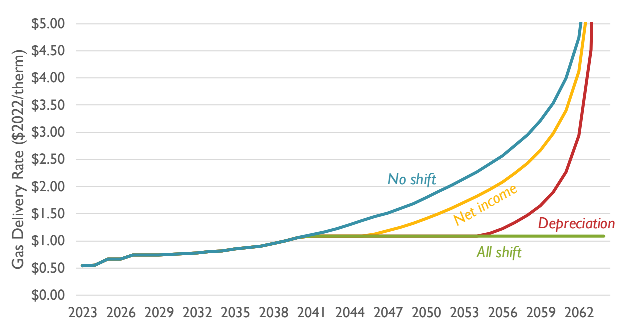
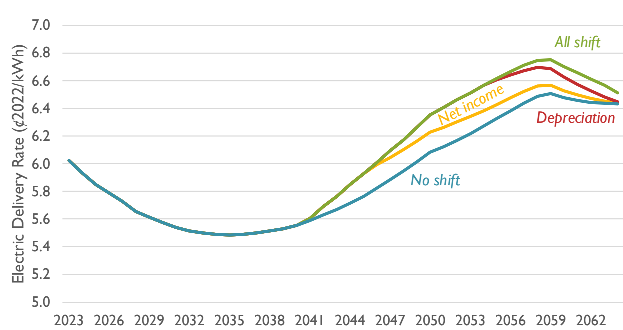


Figure 17. Electric delivery rate in the Managed and Timely Transition (2025) scenario, showing the increases resulting from shifting portions of the gas revenue requirement to the electric utility



The Managed and Timely Transition (2025) case requires the least amount of revenue shifting to meet the modeled cap of a doubled delivery rate, because its gas rates are lowest. In contrast, the Unmanaged Transition (2050) case shows the greatest potential shift, and greatest resulting electric rate impact. Figure 18 and Figure 19 show the gas rates and electric rates in the Unmanaged Transition (2050) case using each of the approaches to shifting revenue between utilities. In this case the sums to be shifted are substantially larger, so the electric rate increases are commensurately larger, with greatest extent of about 1.5 cents per kWh in 2050 (about $180 per year for a typical all-electric household). The shift of costs to electric rates also begins sooner—about 2035 instead of 2040—because gas rates rise more quickly in this case.

The cases with a delayed managed transition approach (2030 and 2035) show intermediate results in terms of average electric rate impact. The timing of their costs corresponds to their given timescales of action. Figure 20 and Figure 21 show the gas and electric rate results, respectively, under approach number 2 (shifting both net income and depreciation costs) for all four gas system management cases. As expected, the extent of cost shifting is lower in the managed cases—particularly the managed cases with earlier transitions—because those cases have lower overall gas rates before the shift.

Figure 18. Gas delivery rate in the Unmanaged Transition (2050) scenario, showing the reductions resulting from shifting portions of the gas revenue requirement to the electric utility

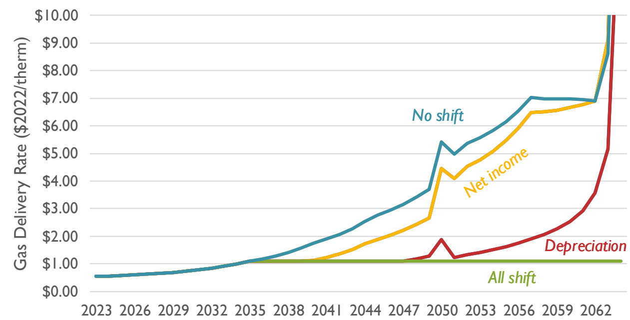


Figure 19. Electric delivery rate in the Unmanaged Transition (2050) scenario, showing the increases resulting from shifting portions of the gas revenue requirement to the electric utility

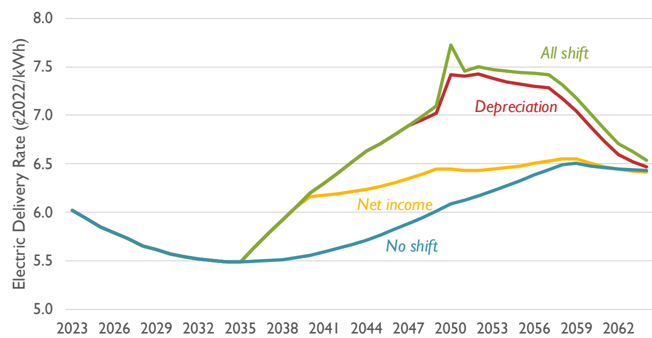


Figure 20. Gas delivery rate across the four transition management scenarios, if net income and depreciation costs can be shifted to the electric utility

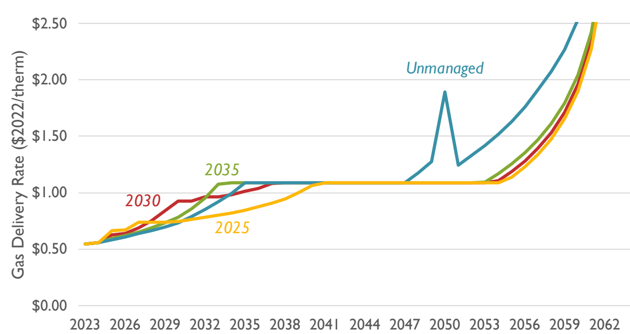
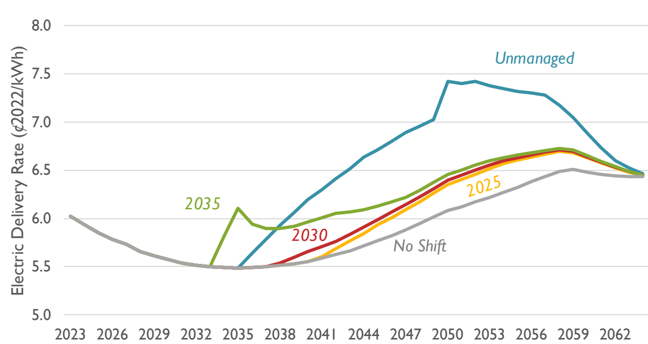


Figure 21. Electric delivery rate across the four transition management scenarios, if net income and depreciation costs can be shifted to the electric utility

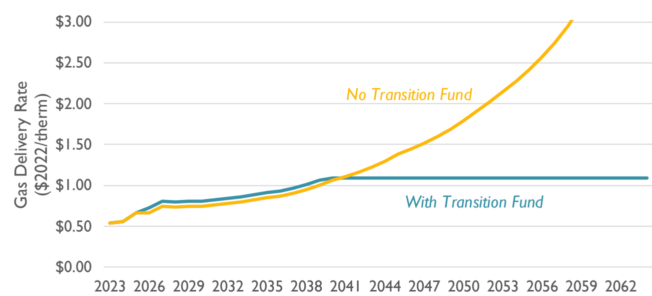


BUILD A TRANSITION FUND

Another approach to limiting future gas rate increases would be to limit building-sector gas rates by populating a gas system transition fund using contributions from today's gas ratepayers. In this approach, gas customers would contribute towards a modest fund in the near term, while gas rates are lower and more customers remain on the system. These funds would offset utility capital and essentially earn the utility's rate of return on behalf of customers as they accumulate. Once rates rise past the level of doubling (or whatever other limit were set), further revenue requirements for the buildings sector would be met by drawing down this fund. Establishing such a fund would require estimates of the future revenue requirement and rates, along with a known plan for the transition of the buildings sector off gas, in order to set aside the right amount. Compared with the fuel-shifting approach detailed above, this approach is therefore less flexible. On the other hand, it does not require coordination with another utility and recovers all costs for the gas system from gas customers.

Figure 22 illustrates the residential gas rate trajectory for the Managed and Timely Transition (2025) case using such an approach, along with the baseline approach without a transition fund. Note that gas rates are higher in the near term and limited after 2040. The rate adder required to fund the transition in this case is $0.062 per therm.

Figure 22. Gas delivery rate in the Managed and Timely Transition (2025) case with and without the use of a transition fund raised from near-term customers and used to limit the future rate to twice today's level, in real terms



In the Delayed Managed Transition cases (2030 and 2035) and in the Unmanaged Transition (2050) case, the required rate adder is higher for two reasons. First, the amount of revenue to be offset in the out years is higher because the total revenue requirement is higher in these cases. Second, there are fewer years between 2025 (when the transition fund is established) and the year each of these delayed cases pass the rate-doubling threshold, and fewer sales to use to fund the transition. In other words, the numerator is larger and the denominator is smaller. Table 2 shows the rate adders required to limit gas rates to double today's rates (in real terms) in each of the four transition cases. In the Unmanaged Transition (2050) case, there is not sufficient time before the rate increases past the doubled-rate limit to raise a sufficient transition fund to cover all future costs (using a doubled-rate cap).

Table 2. Transition rate adders required to limit gas rates to double today's rates (in real terms) in each of the four transition cases

Case	Transition Rate Adder ($2022/therm)	Adder in place through
Managed and Timely Transition (2025)	$0.0617	2040
Managed Transition 2030	$0.0960	2036
Managed Transition 2035	$0.2955	2033
Unmanaged Transition (2050)	N/A	N/A

CONCLUSIONS

In this study, Synapse modeled potential futures for a Washington gas and electric utility adapting to an electrified future, aligned with Washington's SES. Each scenario follows the same pathway for declining pipeline gas use in the buildings and industrial sectors, and the associated reduction in total GHG emissions. Where the scenarios differ is in how the utilities respond to this changing future, and how they take advantage of clustering building electrification to retire gas system assets. Our modeling shows that proactive and prompt action to manage electrification through clustered or neighborhood-level electrification combined with accelerated depreciation lowers overall gas system costs. Timely actions also make it easier and more affordable for policymakers to develop tools that reduce energy burden and increase equity among income groups at any given time, and across time.

Specifically, our modeling shows that:

- For the example of PSE, for each year earlier that the utility chooses to transition to a managed approach, the present value of gas system costs is lowered by $100 to $160 million. Similar results, scaled appropriately, should apply to the state's other gas utilities.
- If action begins in 2025 as in the Managed and Timely Transition scenario, gas delivery rates are lower than any other case starting in 2030, and will be half the rates of the Unmanaged Transition case by the mid 2040s.
- While electrification always offers residential customers annual bill savings after 2030, prompt action by the gas utility to manage the transition reduces the likelihood of an unmanaged and rapid transition off gas and its associated adverse equity and safety implications.
- Shifting gas system costs in time (through a transition fund) or between fuels (through sharing costs with the electric utility) lowers rate pressure on gas customers, and the cost of the shift is lower for each year of more timely and planned action.

While this modeling is necessarily high-level, the results should hold when utilities model similar cases in detail within their full financial and asset management tools. We encourage utility leaders and policymakers to plan for neighborhood-based, clustered electrification, and to take appropriate actions to lower or eliminate stranded cost risk while lowering energy burdens and enhancing equity.

APPENDICES 24

APPENDIX A. STRATEGIC TRANSITION MODEL

Future of Gas proceedings have been created in several states including New York, Rhode Island, Massachusetts, and California to discuss how to transition the gas system to meet state GHG emission reduction targets. Gas rate cases in Ontario and Quebec have raised issues regarding capital recovery risk in an energy transition scenario. All of these proceedings would be enriched by analysis that can demonstrate how a gas utility and its customers could manage a dramatic change in the gas utility's service provided, where a significant percentage of natural gas customers elect to exit the gas system and fully electrify their homes and businesses.

To contribute to these discussions, Synapse developed a financial model of a hypothetical utility, the Strategic Transition Model (STM). This simplified gas model calculates revenue requirements and financial metrics, providing insight into the impacts and correlates of a transition to a smaller gas utility.

This white paper documents the STM's characteristics, outputs, structure, calculations, assumptions, and simplifications. It provides illustrative results for a case in which buildings sector gas use winds down to zero by a fixed date, while gas use remains unchanged among industrial customers served by high-pressure mains and transmission.

Model summary

The STM is a simplified model of a hypothetical utility; the results can be scaled to approximate any gas utility if updated with the appropriate inputs. The STM calculates revenue requirements and financial metrics, providing insight into the impacts of a transition from today's state to a smaller gas utility.

The gas system in transition is characterized and driven by two factors: the rate of customer departure and the quantity of gas consumed. The STM assesses the impact of these changes.

The STM divides the current gas system into a *retiring* system and an *indefinite* system, with retirements based on assumptions about customer departures. The *retiring* system serves residential and commercial building consumers and is characterized by increased customer defection, since heating equipment and other building appliances are relatively easy to electrify. As modeled, this segment exits the natural gas system over time—the utility first retires meters and services as individual customers depart, and then mains as possible with neighborhood retirements. The indefinite system is composed of customers who need to retain the connection with the gas system as they will not fully electrify. For the purposes of model simplicity, we have assumed that these are the utility's industrial customers (assumed to be a proxy that includes other customers directly served by high-pressure distribution mains or transmission).

The STM calculates the income statement for the entire utility, then produces separate income statements for the retiring system and the indefinite systems. Allocations between these two systems (for net plant, depreciation, and operations and maintenance—or O&M) are based on the same kinds of parameters used in cost allocation in rate cases, namely the number of customers and the amount of gas consumed. Because the STM does not track different types of assets at the level of resolution that more complex models might, cost allocation between these two systems, especially in the early years of the model, is approximate.

The STM is designed to have no stranded costs. A key element of the analysis is the depreciation treatment of the utility's assets (gas plant). In the model, all return *of* capital and return *on* capital is recovered as revenue. The model accomplishes this by adjusting straight-line and tax-related depreciation rates for the assets of the retiring system so that assets which retire in each year are fully depreciated at the time of their retirement. The model tracks deferred income taxes associated with each class of asset so that they also reach zero at the time of retirement.

It may seem confusing to use a model in which stranded costs are not possible to evaluate stranded cost risk. In fact, this structure makes the drivers of capital recovery risk associated with the clean energy transition clear and distinguishable: assets become stranded if rates rise to an unsustainable level. By unsustainable we mean that further rate increases reduce revenue by driving customers off the system, rather than increase revenue. In such a situation, it is possible that the utility will not recover its full cost of service, including return of and on its invested capital. Therefore, we can use the STM to look for cases in which gas rates rise to unsustainable levels, as an indication that the utility and regulator would need to work out an approach to managing or mitigating the resulting stranded costs.

The STM provides metrics to illustrate impacts on gas utility customers and other stakeholders. The STM calculates the hypothetical utility's annual revenue requirement and allocates it to customers of the retiring or indefinite systems. This allows us to calculate the potential rate impact per customer and financial metrics of interest to regulators, debt holders, and shareholders such as debt coverage ratios and return ratios.

The STM is designed to be a simple model, and there are numerous aspects of utility finance it does not capture. These simplifications include:

- All assets are treated as part of a single asset type, with lifetime determined by the retirement date and uniform salvage costs.
- O&M costs are only roughly disaggregated.
- Assets retiring in a given year are assumed to be sampled evenly from all ages of existing plant (e.g., rather than targeting retirement of older assets first).[12]

These simplifications result in a tractable model that can capture important ratemaking principles, practices, and risks, and thereby provide useful results to inform planning and policymaking.

Calculations

In this section, we disclose assumptions and describe how the model calculates key accounts. We begin with an explanation of rate base and depreciation expense calculations. The second half describes how the model uses scaling factors to calculate other components.

Gas plant characteristics, growth, and depreciation. The model treats gas plant as broken into blocks of value and elides specific details. We assumed all assets have the same lifetime, depreciation rates, and salvage costs. No distinction is made between traditionally shorter-lived assets (e.g., meters) and longer-lived assets (e.g., mains).

Existing plant build-up to 2023 balance: The model assumes existing plant has been added to the system in a linearly increasing amount over the last 50 years. For example, assume plant installed in 1974 is $1, plant installed in 1975 is $2, etc., increasing by $1 per year until plant installed equals $50 in 2023. The existing plant balance in 2023 in this case is $1,275. These values are in nominal dollars. This approximation reflects both inflation over the time period and increased capital additions over the last 10–20 years, along with retirement of some older assets. The user can adjust the starting date of the linear increase to a date after 1974 in order to match a utility's depreciation reserve balance, if the balance is lower than the default (indicating more recent investments than the default).

Straight-line depreciation method. The model depreciates gas plant using a straight-line method for each retirement year. (Note, this means depreciation rates are consistent with utilization-based depreciation only if the assets are used steadily at their present level until they are shut off.) Assets retiring in a given year (excluding indefinite system assets being reinvested) are assumed to be sampled evenly from all ages of existing plant. This means the model does not address strategic withdrawal and does not consider targeting retirement of older portions of the system first. The model does not explicitly treat fully depreciated assets that are still in operation but not contributing to rate base (such as very old cast iron pipe).

Capital Additions. For retiring assets, STM adds 0.5 percent of plant each year by default (this percentage can be changed by the user). This minimal amount is to account for repairs to maintain system reliability and safety. For the indefinite system, 2 to 4 percent of plant is added each year to reflect a sustained level of investments for assets with a 50-year lifetime, accounting for inflation. Indefinite assets in the default configuration would be transmission and high-pressure/large-diameter pipe. The model also accounts for retirement of older indefinite-system assets and their replacement at a cost equal to the original cost, adjusted for inflation.

Capital Retirements. For retiring assets, all plant retires in its designated retirement year. For indefinite assets, the model assumes the utility retires and replaces plant in its designated retirement year, 50 years after installation.

Capital retirements and O&M change proportionally to customer counts and sales. Customer counts and sales (i.e., gas throughput) are the scaling factors. An increase or decrease of customer count and sales drive a proportional increase or decrease in capex retirements and O&M costs. Current load shape is preserved, thus peak load is adjusted proportionally to sales in each customer class. O&M costs are simplified and based on FERC categories.

Straight-line depreciation converts to accelerated depreciation. At the beginning of the modeling period, STM depreciates all assets using the straight-line method, with a 50-year asset life. The user identifies one year as the point at which the utility's approach to system planning changes, and gas plant in the retiring system is switched to an accelerated depreciation method in that year. Installed and partially depreciated assets see a change in their depreciation rates (both book and tax) to their retirement year. All future capital additions to the retiring system adjust to their new lifetime from their point of addition. For the indefinite system, the depreciation methodology remains unchanged at a 50-year book life approach, with a 20-year MACRS (Modified Accelerated Cost Recovery System) used to calculate depreciation for tax purposes.

Model details

Inputs

Input parameters:

- Financial parameters: Capital structure/ROE
- O&M costs: Broken out by broad FERC categories
- Capital assets: Plant in service and reserve for depreciation
- Allocation of the sales and customers between those served by retiring system and those served by the indefinite system
- Allocation of capital plant and O&M costs between retiring system and indefinite system, as of today
- Allocation of asset retirement over time based on whether customers who depart are clustered
- Average salvage costs
- Year in which the change in approach (between BAU and a retirement/accelerated depreciation model) is made

Calculations

Known simplifications (what the model doesn't do):

- All assets are treated the same (same lifetime, depreciation rates, salvage costs, etc.)
  - No distinction between shorter-lived assets (e.g., meters) and longer-lived (e.g., mains)
- Simplified disaggregation of O&M costs
- Simple scaling of capital retirements and O&M costs with customer counts and sales
  - Assumes peak load (and associated capital) scales with sales (e.g., no change in load shape)
- Straight-line depreciation for assets to each retirement year
- Assets retiring in a given year (other than indefinite system assets being reinvested) are assumed to be sampled evenly from all ages of existing plant
  - No allowance for targeting retirement of older portions of the system first
- Existing plant is assumed to have been added to plant in a linearly increasing amount over the last *N* years. These are values in nominal dollars. This approximation reflects both inflation over that time period and increased capital additions over the last 10–20 years.
  - If actual data are available (e.g., from a depreciation study) they could be used for a closer model of an actual utility
- The model does not explicitly treat fully depreciated assets that are still in operation but not contributing to rate base (such as very old cast iron pipe)

Scaling trajectories:

The model uses a set of inputs to approximate how other model parameters change. This section describes how the model conducts each calculation and scaling.

Inputs:

- Sales and customers by group (retiring vs. indefinite)
- Allocation of distribution mains plant between retiring and indefinite (e.g., 75%/25%)
- Plant broken out by high-level FERC categories:
  - Land
  - Mains
  - Services
  - Meters
  - Storage
  - Transmission
  - General Plant
- Clustering parameter by year
  - This parameter set the proportionality between departing customers and reduction in miles of mains

Calculations:

Phase 1: Set foundational trajectories

- Each trajectory starts at 100% in the start year and changes based on inputs

- Retiring miles (or low-pressure miles if all of low-pressure system is being retired): Scales based on the reductions in number of customers of the retiring system, as modified by the clustering parameter, C:
    - Value = 100% - C*(1-$customers_{year}$/$customers_{start}$)
    - By default, C starts at zero and rises linearly to 1 by 2050
- Peak: Scales with change in total sales
    - Assumes fixed load shape

Phase 2: Apply foundational trajectories to categories of plant

- Mains
    - Retiring/low-pressure mains: Scales with retiring miles
    - Indefinite/high-pressure mains: Fixed at 100%
- Services
    - Scales w/ # of customers
- Meters
    - Scales w/ # of customers
- Storage
    - Scales with sales
- Transmission
    - Fixed at 100%
- Land
    - Weighted average of retiring and indefinite mains
- General Plant
    - Weighted average of all other types of plant

Phase 3: Apply foundational trajectories to categories of O&M

- Storage Expenses
    - Scales with sales
- Distribution Operations Expenses
    - Weighted average of separate trajectories for:
    - Mains
        - Weighted average of retiring and indefinite mains
    - Services
        - Customers
    - Meters
        - Customers
    - General operations
        - Weighted average of plant in mains and services
    - Supervision
        - Weighted average of plant in mains, services, meters, and land
- Customer Account Expenses
    - Scales w/ # of customers
- Customer Service Expenses
    - Scales w/ # of customers

- Sales Expenses
    - Scales w/ # of customers
- Transmission Expenses
    - Fixed at 100% (part of indefinite system)
- Administrative and General Expenses
    - Weighted average of all parts of O&M
- O&M expenses are also scaled up with inflation

Allocation of costs

Costs are allocated to customers on the retiring system (e.g., buildings) and those on the indefinite system (e.g., industry).

Capital cost allocation:

- All capital costs associated with the retiring system are assigned to the customers on that system, allocated between residential and commercial according to their contribution to sales, customers, and demand (as appropriate).
- The indefinite system consists of high-pressure pipes and transmission assets that serve both indefinite and retiring system customers. Capital costs for these assets are allocated between the two groups on the basis of sales.

O&M cost allocation:

- O&M costs are divided into capital-related costs and customer-related costs—administrative and general costs are allocated in proportion to all O&M costs
- Capital-related O&M costs are allocated according to the capital allocator just derived; customer-related costs are allocated based on the number of customers
- Capital-related O&M costs are: storage, transmission, the portion of distribution operations allocated to demand or volume in a cost-of-service study
- Customer-related O&M costs are: customer accounts, customer service, sales, and the portion of distribution operations allocated to customers in a cost-of-service study

APPENDIX B. GLOSSARY

Capex: capital expenditure. Funds used by a utility to install and upgrade physical assets such as mains, meters, compressor stations, and service lines. Generally, long-term assets that are depreciated over their useful life.

Clustered electrification: an approach to electrification in which gas service lines are retired in a grouped manner that allows the gas main that serves those service lines to also be retired. Also referred to as "neighborhood-scale" electrification.

Customer base: the group of people who buy or use a particular product or service. In this report, "customer base" is used to mean the total number of customers on the gas system.

Customer class: categorization of utility customers based on electricity and voltage needs or gas usage. Commonly: residential, commercial, and industrial.

Decarbonization: the process of achieving a zero greenhouse gas emissions future.

Depreciation: the return of capital as an asset ages toward its planned retirement or replacement. Depreciation is used to spread the cost of an asset over its useful life. When an asset is fully depreciated, it is removed from the rate base.

Energy burden: the percentage of a household's gross income that is spent on energy costs. In Washington, customers are defined as energy burdened if they have energy bills that are greater than 6 percent of household income.[13]

Energy transition: the transition from fossil fuel energy sources to renewable and zero-carbon energy sources as part of an economy-wide transition to eliminate greenhouse gas (GHG) emissions.

Gas meters: a device that measures the amount of gas that is delivered to the customer for consumption.

Gas main: a gas pipeline that conducts and distributes gas to multiple service lines.

Large gas pipes: high pressure or large diameter gas pipelines that serve small pipes and large gas consumers such as industrial facilities.

Managed transition: referring to the energy transition, a process by which the utility plans to transition off fossil fuels in a controlled, rather than scattershot, way. In a managed transition, the utility manages the size of its energy system alongside its financial treatment of assets in order to minimize revenue requirements, rate increases, and inequitable outcomes.

Obligation to serve: the requirement for a utility to provide service upon request to all customers that fall in their service territory, with exceptions. In Washington, gas utilities are generally obligated to provide gas upon request to customers in their service territory. As of June 6, 2024, gas utilities may meet this obligation by providing thermal energy instead of gas, subject to commission approval.[14]

Pipeline gas: gas that travels over long-distance pipelines to consumers. It is often derived from fossil fuels, which is commonly known as natural gas, but can also include renewable natural gas or hydrogen.

Plant in service: utility assets that are used and useful in providing service, such as generation, transmission, and distribution assets. Used in the singular ("plant", not "plants") to include all utility assets.

Rate base: the utility's plant in service, minus accumulated depreciation (after making certain tax adjustments). The utility earns a rate of return on its rate base, subject to commission approval. .

Rate case: a formal regulatory process used to determine the just and reasonable rates to charge customers for a utility service.

Regulatory asset: an intangible asset that appears on the utility's balance sheet, corresponding to a cost that would generally be expensed by an unregulated business, such as non-recurring costs for storm recovery. The utility earns a rate of return on its investment in this asset, and recovers the invested capital over time, in the same way as it would for a tangible asset. Regulatory assets are standard tools used in regulatory finance to spread one-time costs over time.

Renewable natural gas: gas extracted from landfills or produced from manure, wastewater, or food waste using anaerobic digesters.

Revenue requirement: the total revenue the utility must realize to pay their expenses and provide a fair return to investors. The revenue requirement consists of the return on rate base, depreciation, and expenses like taxes, operations, and maintenance.

Service line: a gas pipeline that transports gas from the main distribution system to a customer's piping system; also known as a spur line.

"Small pipe" mains: low and moderate pressure gas mains that serve buildings and other low-to-moderate demand customers.

Used and useful: a regulatory term for when a piece of infrastructure is useful for customers and actively serving them.

APPENDIX C. ENDNOTES

1 Waterman-Hoey, S. 2022. Washington State Greenhouse Gas Emissions Inventory: 1990-2019. Washington State Department of Ecology. Publication 22-02-054.

2 Office of Governor Jay Inslee. May 2019. Washington takes bold steps to reduce greenhouse gas emissions from buildings. Page 1. Available at: https://governor.wa.gov/sites/default/files/2023-01/clean-buildings-policy-brief-bill-signing.pdf

3 Washington State Department of Commerce. December 2020. Washington 2021 State Energy Strategy: Transitioning to an Equitable Clean Energy Future. Page 19. Available at: https://www.commerce.wa.gov/growing-the-economy/energy/2021-state-energy-strategy/.

4 Washington State Department of Commerce. CETA Overview and Interim Assessment. Available at: https://www.commerce.wa.gov/growing-the-economy/energy/ceta/ceta-overview/

5 WA State Dept of Commerce., page 18.

6 Industrial pipeline gas use does not decline as quickly because many industrial processes are difficult or expensive to electrify, and turnover of industrial equipment and processes can be very slow compared with the lifetimes of building equipment.

7 See https://www.utc.wa.gov/about-us/about-commission to learn more about the UTC.

8 Both of these approaches reflect expected utility management behavior. Before a utility changes its approach to asset retirement and adopts a neighborhood-level electrification and asset retirement approach, it is likely to increase depreciation rates to reflect shorter useful lives. And regulatory assets are commonly used to mitigate sudden changes in rates, especially those which are short-lived.

9 Recall that we shift the some of the revenue that would have been recovered in a spike at the time the utility begins to manage its transition (resulting from sudden increases in the depreciation rate and recovering what would otherwise have been stranded costs from retired assets) into a regulatory asset. This allows the utility to recover those revenues over the ensuring decade, with a return to compensate it for the delay, in exchange for a smoother rate trajectory.

10 Because we model a gas sales trajectory in line with the SES, the gas utility would generally not have to pay for additional emissions credits beyond the CCA cap.

11 A societal discount rate reflects the time preference of society as a whole and is commonly used when evaluating governmental or societal investments. For example, the U.S. EPA recommends a 1.5, 2, or 2.5 percent societal discount rate when evaluating the social cost of GHG emissions. (See EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances, Section 2.4. Available at https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf.)

12 This reflects the fact that asset ages are likely to be mixed throughout the utility's service territory, and that absent explicit targeted asset retirement programs, customer departures are independent of the age of the gas system assets serving them. Specific utility planning could include such targeting, which would reduce near-term depreciation cost impacts.

13 Washington Utilities and Transmission Commission. September 2022. Issue Brief 3: Energy and Equity in Washington State. Available at: https://www.utc.wa.gov/sites/default/files/2022-09/Issue%20Brief%20%233-%20Energy%20and%20Equity%20.docx

14 The obligation to serve for Washington's utilities can be found here: https://app.leg.wa.gov/RCW/default.aspx?cite=80.28.110