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BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Investigation regarding long-term planning for natural gas utility service in Nevada	)))	Docket No. 21-05002

COMMENTS OF THE CONSERVATION ADVOCATES

1. Introduction

Western Resource Advocates ("WRA"), the Natural Resources Defense Council, Sierra Club, the Nevada Conservation League, The Nevada Chapter of the American Institute of Architects, and Defend our Desert (collectively, the "Conservation Advocates") submit these comments in response to the Procedural Order issued by the Public Utilities Commission of Nevada's ("Commission") in Docket No. 21-05002.[1] The Commission requested interested parties submit comments responsive to the questions outlined in the Procedural Order. The Conservation Advocates respond to each of the questions in Phase 3, as appropriate, below.

2. Phase 3 (i): What are the direct costs to consumers of transitioning to electric appliances?

a. What are the costs of installing new electric appliances?

Table 1 compares the total installed costs of residential electric heat pump options and natural gas furnaces for retrofit projects. Operating costs are addressed in the following section. To make a fair comparison with the cost of heat pumps, these studies include both the cost of installing new central air conditioning ("AC") and the cost of a new natural gas furnace because heat pumps provide energy efficient cooling in addition to heating. A 2018 study by the Southwest Energy Efficiency Project ("SWEEP") investigated the installed costs of electric and

[1] Synapse Energy Economics assisted with the development of these comments.

gas heating options based on a contractor survey. This study found that the costs are very similar when the cost of a new AC is included in the gas option. The cost of a ducted heat pump in the Las Vegas area was slightly lower than the cost of the gas option. Studies by Lawrence Berkeley National Laboratory ("LBNL") and the Rocky Mountain Institute ("RMI") also found similar results for heat pump system costs, specifically that gas with a new AC is more expensive on average.

Table 1. Total Installed Costs of Residential HVAC Retrofits[2]

		Installed Costs		
Study	**Location**	**Heat pump**	**Gas furnace and new AC**	**Gas alone**
SWEEP 2018	Reno	$8,200	$7,937	
SWEEP 2018	Las Vegas	$8,200	$8,679	
LBNL 2021	National	$8,207	$10,955	
RMI 2018	Oakland	$8,641	$11,088	$3,581
RMI 2018	Houston	$8,054	$10,114	$3,156

Note: All heat pump costs are ducted except the LBNL 2021 results, which are a blend of ducted and ductless heat pump technologies.

Table 2 shows a comparison of the total installed costs of electric and gas water heater retrofits based on three studies. The studies found that heat pump water heaters ("HPWH") are generally more expensive than gas storage water heaters. On the other hand, LBNL reported that the cost of electric resistance storage water heaters is the cheapest option whereas gas tankless water heaters are the most expensive option for consumers.[3]

[2] SWEEP, *Benefits of Heat Pumps for Homes in the Southwest*, (2018), available at: https://bit.ly/33EdcoR; LBNL, *The Cost of Decarbonization and Energy Upgrade Retrofits for US Homes*, (2021), available at: https://bit.ly/3q7Dfw1; RMI, *The Economics of Electrifying Buildings: How Electric Space and Water Heating Supports Decarbonization of Residential Buildings*, (2018). Available at: https://bit.ly/321btcS

[3] *Id*., LBNL's 2021 study.

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Table 2. Total Installed Costs of Residential Water Heating Retrofits[4]

		Electric		Gas	
Study	**Location**	**HPWH**	**Electric Resistance Storage**	**Tankless**	**Gas Storage**
LBNL 2021	National	$2,824	$888	$4,004	$1,972
RMI 2018	Oakland	$2,416			$1,426
RMI 2018	Houston	$2,062			$1,228
SWEEP 2018	Southwest	$2,300			$1,640

The costs of commercial heating and cooling system retrofits are much harder to compare as there are numerous building types and the data sources are sparse relative to the variety of building types. Table 3 presents the total installed costs of commercial HVAC systems from three different sources. The costs are presented in total costs per ton, per thousand BTUs per hour ("MBH"), and per square foot, and incrementally per ton. A study by Group 14 Engineering examined heating and cooling options in Colorado and determined that the costs for heat pumps and gas-plus-AC options range from $2,400 to $2,600 per ton. The American Council for an Energy-Efficient Economy ("ACEEE") provided cost estimates in various units including incremental costs per ton, concluding that commercial heat pump options cost between $300 to $470 more per ton than the corresponding gas-plus-AC options. Based on the total cost estimates per ton provided by ACEEE, these incremental cost estimates represent a 10 to 20 premium. The Commission should also consider RMI's comments filed in this phase of this Docket that include a cost effectiveness assessment for mixed fuel vs. all-electric new residential construction in Las Vegas.

[4] *Supra* note 2.

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Table 3 Total Installed Costs of Commercial HVAC Retrofits[5]

Study	Location	Fuel	Building type	Technologies	Cost Unit	Installed costs
Group 14 2020	Colorado	Electricity	Office buildings	Packaged heat pump	Per ton	$2,400 - $2,600
Group 14 2020	Colorado	Gas	Office buildings	Gas-fired/DX rooftop units	Per ton	$2,400 - $2,600
Betony 2021	Los Angeles	Electricity	Large commercial	Heat pump	Per sq. ft	$19.00 - $28.00
Betony 2021	Los Angeles	Electricity	Small & medium commercial	Heat pump	Per sq. ft	$4.00 - $11.33
ACEEE 2020	National	Electricity	Average of Multiple	Heat pump packaged unit (relative to gas packaged unit)	Incremental cost per ton	$292
ACEEE 2020	National	Electricity	Average of Multiple	Split system heat pump (relative to gas furnace and split system AC)	Incremental cost per ton	$467
ACEEE 2020	National	Gas	Average of Multiple	Gas space heaters	Per MBH	$26
ACEEE 2020	National	Gas	Average of Multiple	Gas-fired boiler	Per MBH	$33
ACEEE 2020	National	Electricity	Average of Multiple	Ductless mini splits	Per ton	$1,730
ACEEE 2020	National	Electricity	Average of Multiple	VRF	Per ton	$2,863

Table 4 presents the total costs of commercial water heater retrofit options from two studies. A study by Group 14 Engineering ("Group 14") found that the cost of an HPWH is substantially more expensive than the cost for a storage water heater for office buildings in Colorado.

[5] Group 14 Engineering, *Electrification of Commercial and Residential Buildings*, (2020) available at: https://bit.ly/3skNqAp; Jones, Betony, *Los Angeles Building Decarbonization: Community Concerns, Employment Impacts, and Opportunities. Inclusive Economics* (2021), available at: https://on.nrdc.org/3q2wziZ; ACEEE, *Electrifying Space Heating in Existing Commercial Buildings*, (2020) available at: https://bit.ly/3yC6s67

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Table 4. Total Installed Costs of Commercial Water Heating Retrofits[6]

Study	Location	Fuel	Building type	Technologies	Cost Unit	Installed costs
Group 14 2020	Colorado	Electricity	Office buildings	HPWH	Total	$4,200
Group 14 2020	Colorado	Gas	Office buildings	Tank type domestic hot water heater	Total	$2,600
Betony 2021	Los Angeles	Electricity	Large commercial	HPWH	Per sq. ft	$0.44 - $0.52
Betony 2021	Los Angeles	Electricity	Small & medium commercial	HPWH	Per sq. ft	$0.79 - $0.88

Table 5 compare electric and gas cooking system costs.

Table 5. Costs of electric and gas cooking systems for residential and commercial buildings[7]

Study	Location	Fuel	Sector	Technologies	Costs
California eTRM	California	Gas	RES	Natural gas cooktop	$1,192
California eTRM	California	Gas	RES	Natural gas range	$834
California eTRM	California	Gas	RES	Natural gas wall oven	$1,305
California eTRM	California	Electricity	RES	Induction cooktop	$1,636
California eTRM	California	Electricity	RES	Electric range with electric resistance cooktop	$708
California eTRM	California	Electricity	RES	Electric range with induction cooktop	$1,657
California eTRM	California	Electricity	RES	Electric resistance wall oven	$1,541
California eTRM	California	Gas	COM	Gas half-size	$4,674
California eTRM	California	Gas	COM	Gas full-size	$4,434
California eTRM	California	Electricity	COM	Electric half-size	$4,719
California eTRM	California	Electricity	COM	Electric full-size	$5,646
HIRL 2021	National	Electricity	RES	Electric Range, 30", freestanding, min.	$655^
HIRL 2021	National	Electricity	RES	Induction cooktop	$1,474^
HIRL 2021	National	Gas	RES	Gas range	$670^
Betony 2021	Los Angeles	Electricity	RES	Electrification	$1,400-$2,900

Note: ^ includes labor costs.

6 *Id*.

7 Cal TF, electronic Technical Reference Manual (eTRM) available at: http://www.caltf.org/etrm-overview; Home Innovation Research Labs, *Cost and Other Implications of Electrification Policies on Residential Construction* (2021), available at: https://bit.ly/3sg2q2o; Betony, *supra* at fn. 5.

Overall, electric induction cooking equipment is similar, but slightly more expensive that gas cooking equipment.

b. What are the relative operational costs of electric appliances compared to natural gas appliances?

Operating costs differ by region based on regional gas and electric prices. Thus, studies on operating costs in other regions need to be carefully interpreted. Among all the studies we reviewed, the most relevant study is SWEEP's 2018 study that examined the cost of operating heat pump and gas systems for both space and water heating in Nevada and a few other southwestern states.[8] Table 6 presents a summary of lifetime operating costs in net present value ("NPV") for space heating and cooling. The SWEEP study found that the NPV of energy costs associated with heat pumps are lower for new construction and slightly higher for retrofits in both Reno and Las Vegas. The primary reasons for the low operating costs of heat pumps for new construction are: (a) the study assumes all electric new homes do not pay fixed monthly charges for natural gas service and (b) ductless minisplit heat pumps assumed for new construction are more efficient than ducted heat pumps. Lastly, it is important to note that electric prices used in this analysis are average prices. Worth noting is that the available time-of-use ("TOU") pricing tends to favor heat pumps because the TOU rates offer low prices during the winter. Thus, heat pumps are likely economically better retrofits with TOU pricing than the SWEEP study suggests.

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[8] *Supra* fn. 2.

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Table 1. SWEEP 2018: NPV of lifetime energy costs for heating and cooling

Study	Location	Project type	Electric		Gas
			Ducted heat pump	Ductless heat pump	Gas furnace and AC
SWEEP 2018	Las Vegas	Retrofit	$8,413		$7,134
SWEEP 2018	Las Vegas	New construction		$5,135	$7,290
SWEEP 2018	Reno	Retrofit	$8,834		$6,307
SWEEP 2018	Reno	New construction		$5,989	$7,008

The SWEEP study presented the operating cost results for water heaters only as part of the NPV cost difference between heat pump water heaters and gas water heaters including the higher upfront cost of HPWHs. The study found that for retrofits, heat pump water heaters cost $644 more in Las Vegas and $703 more in Reno in NPV over the life of the equipment.[9]

Table 7 presents a summary of operating costs from a Group 14 study in Colorado. In Group 14's study, the annual operating costs associated with electric heating, cooling, and water heating in an example commercial office building were more expensive than a gas alternative by about $586 per year (about 1 percent). However, Group 14 found that with TOU rates, annual energy costs for heat pump and HPWH decreased by $3,222 annually.

Table 7. Annual operating costs of HVAC and water heating for commercial buildings

Study	State	Sector	End-use	Electric		Gas
				HPWH and Heat pump	HPWH and Heat pump (with TOU)	Gas heating, gas water heating, and AC
Group 14 2020	CO	COM	HVAC, water heating	$55,617	$52,395	$55,031

Overall, our review found that the operating costs between electric and gas appliances are similar, but that TOU rates make electric options more attractive.

[9] *Id*. at p. 24, Table 9.

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c. What are the costs of retrofitting a home to accommodate electric appliances, including electric heating systems?

Some studies estimate the cost of upgrading electrical circuits and panels to accommodate electrification. For residential buildings, such costs ranged from about $1,600 to $4,000. A study performed by Group 14 in Denver, Colorado, estimated a cost of $3,000 per commercial building and $1,500 per residential single-family building. However, recently-built homes may avoid these costs, as new homes have a high electrical capacity. These costs can also be avoided by using low amp appliances. For example, several manufacturers have developed and are currently testing 120 Volt, 15 amp plug-in HPWHs that do not require any electrical upgrades that may be introduced as early as 2022.[10]. Also note that not all costs will be attributable solely to building electrification. Consumers who adopt electric vehicles may choose to upgrade their electric service to charge them more quickly and incur increased costs independent of building electrification. Even if the initial driver to upgrade electric service was building electrification, these costs will be complimentary to electric vehicle adoption, and vice versa.

Table 8. Cost of upgrading electrical circuits and panels[11]

Study	Location	Fuel/options	Sector	Building type	End-use	Installed costs
ABC's of Electrifying Your Gas Appliances (2021)	California	Electrification	RES		Electric panel upgrade	$1,300 to $3,000
ABC's of Electrifying Your Gas Appliances (2021)	California	Electrification	RES		Electric Circuit upgrade	$300 to $1,000
Group 14 2020	Colorado	Electrification	RES		Electrical modification	$2,100
Group 14 2020	Colorado	Electrification	COM	Office building	Electrical modification	$3,000

[10] CleanTechnica 2021. "120 Volt Heat Pump Water Heaters Hit The Market & Make Gas Replacements Even Easier" Available athttps://bit.ly/3GTDFx2

[11] Active San Gabriel Valley, et al., *The ABC's of Electrifying Your Gas Appliances* (2021). available at: https://bit.ly/3E0lAvr, Group 14 Engineering, *supra* at fn. 5.

3. Phase 3 (ii): Should natural gas service be extended to new residential developments? If so, should new residential developments be required to accommodate the use of electric appliances? Phase 3 (iii): Should natural gas use/service be expanded under any circumstances?

In considering further extension and expansion of the gas system, the Commission needs to consider the risk of creating additional stranded costs and the societal costs of the expansion compared to alternatives. The Commission should also ensure customers receive price signals that encourage them to take societal cost-reducing actions. Accordingly, the Commission should modify its decision-making process to include societal cost analysis, consider customer costs, and eliminate or dramatically reduce gas line extension allowances. If a proposed expansion does not pass threshold requirements for these analyses and the utility pursues the expansion anyway, investors should bear the entire risk of the investment.

a. Stranded costs

In determining whether to extend gas service to new developments, additional towns, or industries, the Commission should consider the risk of creating stranded costs in the future. Stranding happens when the utility is unable to recover the value it expected when the investment was made as a result of changes in policies, markets, economics, or other factors. New gas assets risk being retired before the end of their design lives because meeting climate targets will require reduction in use of the gas system. New services and mains can have design lives of 50 years or more.[12] That means that a service or main installed today could still be in operation in 2071 absent regulatory intervention. If utilities use design lives as the basis of depreciation, some assets

[12] See generally Application of Southwest Gas Corporation for authority to increase its retail natural gas utility service rates and to reset the Gas Infrastructure Replacement Rates for Southern and Northern Nevada, Docket No. 18-05031, Vol. 6 – Depreciation Study. For example, see the discussion included at p. 96/183 "Account 376.00 Distribution Mains".

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would have 40 percent undepreciated balances on the books in 2050, the year that Nevada aims to achieve zero or near-zero greenhouse gas emissions. Notably, many of these assets will be increasingly underutilized or entirely unused leading up to 2050 as a result of declining gas consumption. Absent regulatory treatment to use a different depreciation lifetime, new gas system investments pose a considerable risk of becoming stranded.

b. Analyzing the societal cost of gas extension and expansion

The Commission should perform, or require the utility to perform, a cost-benefit analysis that compares the extra costs that would be incurred from expansion and/or extension with the extra costs of alternatives like meeting energy needs with electric heat pumps, similar to the Commission's existing societal cost test. The relevant costs to consider include the following:

- The gas system infrastructure costs of the expansion or extension, including the costs of extending the main and the distribution system within the development, services, and metering.
- The social marginal cost of the gas that will be used in end-use equipment in the expanded-to area. Using social cost is important because this will ensure that the climate damage from using fossil fuels and other air pollution impacts inside and outside the home are considered, consistent with Nevada's goals to reach near-zero emissions by 2050. Using the marginal cost in this type of analysis, instead of an alternative such as the per-therm retail rate, is important because the retail rate includes many costs that will not be affected by the expansion. To the extent there are variable operations and maintenance ("O&M") costs that would be caused by the expansion, these should be estimated and included.
- The cost of gas demand side equipment, including piping within the home and combustion appliances.

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- If the alternative being analyzed is electric heat pumps, the analysis should include:
  - The costs of any incremental electricity distribution system infrastructure necessary to serve higher electricity demands in a building. Incremental is emphasized because buildings already take electricity service. In practice, this increment may be zero, depending on the preexisting level of service.
  - The social marginal cost of the electricity to be used in the incremental appliances installed to avoid expanding gas service. Long-run marginal costs should be used here because these estimates consider not just the cost of the marginal thermal unit, but also the extra renewable energy that will be added to meet the increased load, pursuant to the mandated RPS.
  - The cost of electric demand side equipment and any additional electrical costs.

This analysis will yield the total social marginal cost for the gas extension and/or expansion and its alternative. The only difference between analyzing an extension to a residential development and extensions to new towns or industries is the scope of costs included in the analysis: costs of extending the transmission and distribution system to the industry or community need to be included when analyzing system expansion.

In the case of residential customers, this analysis is likely to show that gas expansion does not make economic sense. This results from several factors:

- Customers will, in all cases, already install some level of electricity service. This means that while all extra gas infrastructure costs need to be attributed to an extension or expansion, only some electricity infrastructure costs will be attributed to electrification.
- The social marginal cost of fueling a heat pump appliance with electricity improves over time as renewable energy represents an increasing share of energy on the grid. There is no similar improvement for gas, as the alternatives, like biomethane, are limited in

availability, at-best GHG-neutral, have the same or worse direct use air quality problems as fossil gas, and are expensive.

- The costs of gas appliances are comparable to their efficient electric alternatives.
- Remaining candidate towns for expansion are low in population, have a high average temperature, or are far from an existing gas pipeline. Thus, new locations would likely to fail a comparison with electricity. For example, Virginia City, though cold, is small, with just around 700 residents in 2016. Replacing gas or propane appliances with efficient, electric ones is likely to be much less costly than extending pipelines. Another example, West Wendover, is cold, but far away from a pipeline. Finally, Pahrump is both warm and far from a pipeline.[13]

To conduct this societal cost analysis, the Commission needs to examine gas extensions or expansion projects in relation to other fuels. This analysis is necessary when two regulated industries are competing, as was the case with trucks and railroads in the second half of the twentieth century.[14] While cross-fuel analysis has already happened in Nevada, utilities have used bad assumptions and inappropriate methodologies. In the Spring Creek docket, for example, Southwest Gas ("SWG") used erroneous assumptions, such as ignoring heat pumps, when it conducted the customer-level cost-effectiveness analysis used to help justify its project.[15] The BTU conversion for electricity SWG relies on imposed a coefficient of performance of 1.0 on the electric appliances, when heat pumps are 2-4 times more efficient than that. In the same docket, SWG also did not present a rigorous cost-effectiveness analysis

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[13] See Application of Southwest Gas Corporation for authority to expand its gas infrastructure, recover costs of the gas infrastructure expansion project through alternative cost-recovery methodologies, and amend Certificate of Public Convenience and Necessity ("CPC") 2627 Sub 6 to expand its service territory to include areas located in Spring Creek, Nevada, Docket No. 19-06017, Direct Testimony of Paul Maguire, October 24, 2019, p. 10-11.
[14] See the discussion in Alfred E. Kahn, *The Economics of Regulation: Principles and Institutions*, Cambridge, MA, USA: MIT Press (1988), at 159-163.
[15] See *supra* fn 12, Direct Testimony of Randy Cunningham, at 11-12, Q&A 24.

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that included consideration of a full range of alternatives and an honest appraisal of their benefits. Instead, SWG presented an analysis of the expansion as a construction project, with impacts on employment, taxes, and other factors that are of interest to policymakers but that do not belong in a cost-benefit analysis.[16] Any utility construction project will have employment and tax base impacts; but projects have to be justified primarily on their long-run marginal costs to society, compared to alternatives.

c. Ensuring customers receive good price signals

A societal cost analysis is likely to show that gas line extensions and service extensions to new communities or industries do not make sense. Customers don't pay just marginal costs on their electricity or gas bill; they pay rates that reflect the total costs of utility service. Marginal cost analysis like that above should be supplemented with analysis from a customer perspective, such as that discussed by RMI in this phase of the proceeding. RMI's analysis is especially useful where it contradicts the conclusion of societal analysis, because that shows places where rate design is not accurately reflecting the marginal costs of gas service and its alternatives.

d. The PUCN should eliminate gas line extension allowances

Utilities typically provide new gas connections to customers at no charge up to some cost or length of pipe. For SWG, these connections are subject to an allowable investment that reflects the maximum amount that SWG will invest in new facilities such that anticipated revenues from the new facilities provide the utility's authorized rate of return.[17] While the allowable investment is calculated based on expected return from the specific investment, the allowable investment is rolled into the

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[16] See Application of Southwest Gas Corporation for authority to expand its gas infrastructure, recover costs of the gas infrastructure expansion project through alternative cost-recovery methodologies, and amend Certificate of Public Convenience and Necessity ("CPC") 2627 Sub 6 to expand its service territory to include areas located in Spring Creek, Nevada, Docket. No. 19-06017, Prepared Direct Testimony of Amy Timperley, p. 15, Q&A 28.
[17] Southwest Gas Corporation, Nevada Gas Tariff No. 7. Effective August 8, 2018. P.U.C.N. Sheet No. 184, 2nd Revised.

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utility's overall cost of service. In the event that a customer uses less gas than expected, SWG can require the customer to pay the difference to recover its full investment with its allowed return. This places all risk for line extensions on the customers served and encourages the utility to invest, even where it will not benefit customers, to earn nearly risk-free returns.

4. Phase 3 (iv): How should recent expansions, including projects in Spring Creek (Docket No. 19-06017) and Mesquite (Docket No. 17-11008), be handled?

A. Should the newer systems be planned for as longer-lasting system segments?

To the extent that investments for the expansions in Spring Creek and Mesquite have already been made, they represent sunk costs. The Commission approved the Spring Creek expansion based on a settlement that reflected a negotiation of varied interests.

While these investments may represent some of the longer-lived assets on SWG's system, these assets should not get an exemption from overall carbon policy. Planning for these segments (e.g., for their maintenance while the expansion as a whole is still in service) should still be consistent with the state's carbon targets. Also, these assets should still be evaluated for future retirement based on a societal cost test.

B. Do these systems retain their Rule 9 waiver and continue building out to new customers in the expansion footprint?

As discussed above, new gas extensions should only be approved if they are justified by rigorous review and analysis of cost-effectiveness, including carbon costs. Even new services should be subject to stringent cost-benefit standards. This high bar is necessary for the state to meet its climate targets. Such an analysis is also reasonable given that cost-effective electric end-use alternatives are widely available and that the buildings almost certainly are or will be hooked up to an electric system increasingly powered by renewable energy.

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5. Phase 3 (v): If natural gas sales decline, at what point does the gas system become operationally and financially unviable?

Financial viability

There is no single definition of the gas system becoming “financially unviable.” Gas utilities can find themselves in variety of challenging financial situations that may result from a wide range of circumstances that may be associated with the quantity of gas sold. Some potential indicators relate to present (i.e., a snapshot of the company’s revenues and expenses) and future (the company’s future plan may not be promising enough to warrant investment) circumstances. Potential definitions of unviability could include:

- The utility is unable to raise equity investment at a typical cost of equity for regulated utilities.
- The utility is unable to borrow (or sell bonds) at a typical cost of debt for regulated utilities.
- The utility is unable to charge customers a rate that would allow it to recover its approved cost of service while earning its approved return on equity.
- The utility is unable to return any profit to compensate its equity investors.

Unviability could also be defined as the point at which it becomes clear that any of the above circumstances will become true in the future because of the impact that could have on investment today. For example, if it became clear that a utility would, in the future, not be able to earn a reasonable return on equity, the utility’s ability to raise capital could be diminished immediately.

Financial viability of a gas or electric utility does not require growth in sales, ratebase, or number of customers. In fact, the prudent management of a viable utility (which all of Nevada’s

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utilities are today) should manage equity, debt, and the utility's balance sheet to control risk even as the business changes with reductions in sales. Whether a utility remains viable while sales fall depends on whether the utility manages the reduction well that may include the following actions:

- Accelerate depreciation so that future revenue requirements are lower and there is less net plant at risk, and so there is less need to earn a given profit in dollar terms;
- Limit and optimize investment in expanding or replacing gas infrastructure, which increases revenue requirements and capital at risk, to only those investments assured of earning a return for its investors, and;
- Contain O&M costs by becoming more efficient and retiring portions of the gas system when and where possible.

One way to consider gas system financial viability is to ask at what point residential customers would start to depart the gas system based on the economics of gas compared with electric service. This departure could occur end-use by end-use (load migration) or customers could choose to disconnect from the gas system entirely (network migration). The critical question is what level of gas rates is required to trip off the cycle of migration because either load migration or network migration increase gas service rates for remaining gas customers.[18]

Both rooftop solar policies that produce sustained and growing markets and utility-run energy efficiency programs show that residential customer adoption increases near the point that an investment offers a 6-to-7-year simple payback.[19] We use that rough range as a potential

[18] Note that efforts to use rate design to lower variable rates to fight load migration would require high fixed charges, which in turn could encourage network migration. Striking a balance here requires careful consideration of customer needs.

[19] Commercial customers generally require a faster payback, on the order of 1 to 3 years; however, we focus on residential customers for this following discussion.

threshold for examining the gas rates where electrification becomes attractive for Nevadans.

We first examine the case of a Nevada household with an existing gas storage water heater. When the existing unit is relatively new, the financial return for operating the new appliance would have to be very high to entice a homeowner to replace it. As the unit ages, a homeowner may contemplate replacement-likely between a new gas unit or a HPWH.

If gas rates in Nevada rise above about $1.50/therm, a customer replacing an old gas storage water heater at the end of its expected life will see a payback of between 6 and 7 years by instead installing an electric alternative.[20] Depending on gas commodity prices, this rate is possible when sales fall by about a factor of two to three from current levels, provided that the gas utility's revenue requirement does not increase (as it could through increased costs related to gas infrastructure expansions). If the homeowner takes advantage of NV TOU rates and shifts water heater consumption off of the summer peak periods, their average cost for additional electric consumption could fall to roughly 6 cents per kilowatt-hour.[21] At that rate, an HPWH would offer an attractive payback at time of replacement if gas rates rise above about $1.20/therm. This gas rate might require only a one-third reduction in gas sales or sustained high gas commodity prices. Customers who rationally expect gas rates to rise into the range of attractive payback during the next few years may act on their estimate of the future gas rates, rather than today's rates.

At even higher gas rates, customers could find it attractive to abandon even mid-life gas appliances and switch to electricity. At such levels, the financial viability of the gas utility would be very much at risk, unless it is adequately prepared. For electric rates of 6 to 11 cents, a

[20] This estimate uses current NV Energy default electric rates (that is, non-time-varying rates of a bit less than 11 cents per kWh, based on https://bit.ly/3p65mfX and https://bit.ly/3GSkB29), equipment costs from SWEEP's 2018 study, *supra* at fn. 2, that assumes about 120 therms/year of gas use for hot water,
[21] See generally NV Energy TOU tariffs, located at https://bit.ly/30F9IkS

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Nevada household might be expected to discard a five-year-old gas water heater in favor of a heat pump water heater is when rates rise into the range of $2.20 to $2.50 per therm.

The same logic as just applied to water heating also applies to space heating. Using equipment costs from SWEEP,[22] a heat pump system is less expensive than the combination of a furnace and AC in the Reno area. This means that if both the furnace and AC are due to be replaced, a heat pump will save money up front. However, at current default rates, the heat pump will be more expensive to operate. Using today's TOU electric rates, however, the heat pump will be less expensive or have comparable costs to operate in both northern and southern Nevada. This means that the threshold for increased heat pump adoption for space heating has already been met for simultaneous-replacement systems.

In practice, however, homeowners tend to replace only the furnace or air conditioner at any given time. To give a better sense of when the gas system's long-term viability may be threatened, we consider the case of replacing a furnace and AC system when it is in mid-life (about 10 years old). If replacing such a system with a heat pump offered a 6-to-7-year payback, we would expect substantial and accelerating departures from the gas system. Using the available TOU electric rates, this threshold would be met at gas rates of about $1.50/therm in northern Nevada and $2.40/therm in southern Nevada. This indicates that the threshold indicative of unviability for space heating is closer in the colder portions of the state.

Operational Viability

We look forward to the responses from the utilities regarding operational viability. Also, please refer to the Conservation Advocates' comments in Phase 2.

[22] SWEEP 2018 *supra* at fn. 2, see Table 1, p. 11.

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6. Phase 3 (vi): If customers defect from the gas system or consume less natural gas, what can be done to protect remaining customers from paying higher rates and still allow the utility to recover the costs of investments that were based on forecasts of demand for natural gas that are no longer accurate?

Utilities have the opportunity to earn their approved return on equity and the return of the capital invested in infrastructure that is used and useful consistent with prudent utility management. That is, they have the opportunity for both return *of* capital and return *on* capital. The return *of* capital is accounted for through annual depreciation, while the return *on* capital to equity investors comes from revenues that exceed expenses (including interest on debt).

Regulation seeks to replicate the feedback that a competitive market provides to non-monopoly firms. In a competitive market, imprudent management is admonished with reduced market share and earnings. It is not strictly a given that a utility must be allowed to recover all of its invested capital, plus a return, from its ratepayers. For example, the Commission should carefully scrutinize any future gas infrastructure expenditures based on inaccurate modeling. Especially following the discussion in this docket, the gas utilities should be realistically modeling all future sales and number of customers consistent with deep decarbonization. Moreover, the utilities should be well aware that continuing to pursue additional gas expenditures based on flawed or inflated future forecasts is imprudent and cost recovery may not be approved.

For prior investments already approved by the Commission, there are several considerations. Once an asset is no longer "used and useful", its undepreciated balance could be treated in a number of ways. There are options for who pays for this balance. In the context of substantially declining sales, return of and return on capital may result in rates that are too high to be "just and reasonable," because they cause unreasonable harm to remaining customers or are

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high enough that they would exacerbate the gas utility's challenge in retaining load. This case raises similar questions of cost allocation as in the case of assets no longer used and useful.

The primary choices for who pays for the gas system are gas ratepayers, utility investors, electric ratepayers, or taxpayers. The overall cost can be apportioned among these groups. For example, investors could be assigned the full cost for assets that are no longer used and usefu. This approach reflects the risk of investing in the utility and for which they have generally been rewarded with a rate of return above the risk-free rate. Or investors could lose return on the investment, but another group could pay the cost of returning the capital itself: this is the case if the asset value is amortized rather than capitalized. Gas ratepayers could also pay the full undepreciated value of a retired asset as a regulatory asset on which the shareholders can still earn a return, perhaps with a different depreciation lifetime than the physical asset had.

Mechanisms for Cost Recovery

If costs are allocated to ratepayers or taxpayers, the next question is the preferred mechanism, or "how to collect". Commission may consider accelerated depreciation, securitized assets, and targeted incentives.

With accelerated depreciation, cost recovery can be adjusted to reflect the time period over which an asset is expected to be used and useful consistent with policy objectives, rather than solely based on its engineering life, to minimize the likelihood that these assets will become stranded in the future. For a new investment, if the decision to proceed with the investment is prudent, the asset lifetime assumed for assessing the cost-effectiveness of the proposal and for its depreciation should reflect these expectations. The Commission could shift the depreciation schedule for existing assets, but it must be done carefully to avoid over-recovery.

Accelerating depreciation lowers the total amount shareholders receive because their funds are not earning a return for as long; however, shareholders get the return of their capital

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more quickly and thus, could re-invest those funds. On the consumer side, accelerated depreciation will result in higher distribution rates for those remaining on the gas system, all else equal. Front-loading recovery to align with the time when most customers are still connected may result in a more stable rate trajectory and could avoid leaving a small number of customers to pay the full remaining depreciation cost. This may allow utilities to recoup investments sooner than expected, but the higher rates may also accelerate defection from the gas system.

Securitization can mitigate the problem of excessive charges facing remaining customers. Securitization is analogous to refinancing your mortgage by exchanging a higher interest rate for lower-cost debt. Securitization leverages the lower cost of capital that the utility or a regulator could achieve with a bond, issued in order to pay the shareholders for the value of their remaining investment. The bond could be paid off using gas rates, tax revenue, or even electric rates, and could have a repayment time that is different from the useful or engineering lifetime of the asset. However, securitization generally requires enabling legislation and it must be implemented properly in order to maximize the benefit for ratepayers. For instance, if securitization isn't properly structured, it may eliminate the regulator's ability to hold the utility accountable for decision making that is imprudent, illegal, or not in the public interest. In that way, the utility may be effectively absolved of responsibility for poor business practices or wrongdoing.

These different cost mechanisms can be used in combination with each other. They can also be used in concert with measures to manage how and when customers leave the gas system. Runaway fuel switching could leave stranded costs with no or few customers to pay for them. Customer defection can be managed with targeted financial incentives, for example to encourage electrification by customers on parts of the gas system that are aging and should be retired rather than replaced. Exit fees can result in a more stable revenue stream for the gas utility. However, exit fees will discourage customers from electrifying; if such customers replace existing gas

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equipment in kind at the end of its life, instead of paying the exit fee, they may be unwilling or unable to switch off of gas service for years to come. Customers may also retain a token amount of gas use to avoid the fee, and thereby cause considerable O&M costs to maintain a larger gas network. Exit fees could also prove very challenging for customers least able to electrify—such as low- and moderate-income customers and renters, who face larger barriers to electrification. Low-income customers, for example, generally lack funds or the ability to borrow funds in order to make improvements to their residence. It will be important to implement special rates or protections for these customers. Targeted programs to help these customers electrify their end uses will be essential to mitigate the risk that they will be the only ones left to pay for stranded gas assets.

Controlling costs

Utility managers can foresee the risk that rates may rise to the point of not being just and reasonable, and should be aware of state and federal GHG policies. Prudent utility management therefore requires not just making prudent investment decisions in the context of a transitioning energy sector, but also prudent decisions regarding depreciation and O&M activities. Imagine the case of an imprudent utility manager who fails to adjust depreciation lifetimes to align with the expected useful life of an asset. If that asset reaches the end of its useful life while still having an undepreciated balance, the manager's imprudent decision should require that the shareholders, not ratepayers or taxpayers, cover the shortfall. Similarly, investment in new assets that could increase stranded cost risk should be carefully screened for prudence, given what utilities and regulators know now about the need for gas during the assets' lifetimes.

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A substantial portion of the depreciation of utility pipeline assets is set aside to cover the net cost of removal of the assets.[23] If portions of pipe, including service lines, are formally abandoned, this could reduce removal costs. It should be less expensive to purge and seal a section of pipe than to dig up the whole thing. If the net removal cost for the largest underground asset types in ratebase (mains and services) were reduced, the accumulated reserve for depreciation would cover a larger fraction of the asset value. Basically, shareholders would have received a larger portion of their "return of capital," and therefore face less risk and require less additional capital to be raised from existing/remaining customers.

Formal abandonment of gas assets should be accomplished with a careful eye to safety. The Pipeline and Hazardous Materials Safety Administration ("PHMSA") regulates pipeline safety and has formal regulations that govern pipeline abandonment.[24] These regulations require that:

> "Each pipeline abandoned in place must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard."

If Nevada pursues a policy of formally abandoning pipelines that are no longer used, the safest course of action would be to follow the PHMSA abandonment process to purge and seal the pipes. PHMSA does not recognize a pipeline status other than "active" or "abandoned"; if the unused pipes were not purged and sealed they would need to be maintained as though they were active.

[23] For example, SWG sets aside 20 percent of the cost of mains and 25 percent of the cost of services. See *supra* at fn 12.
[24] See 49 CFR 192.727, "Abandonment or deactivation of facilities".

7. **Phase 3 (vii): How can demand forecasting and planning by natural gas utilities be improved to incorporate consideration of electrification and/or other measures that reduce natural gas sales?**

The Commission should take a hard look at current gas planning processes. An effective planning process must consider Nevada's multiple, sometimes competing, policy objectives. At a minimum, these goals include achievement of carbon targets, cost management, customer protection, reliability, safety, and equitable access to essential energy services. Gas and electric planning processes should be integrated, using the same assumptions and forecasts for electrification. All plans should achieve climate targets. Further, load forecasting should be modernized and standardized. Load forecasts and plans should account for potential and expected changes in end-use technologies and customer behaviors that are not observed in historical trends, such as electrification, energy efficiency programs, building energy codes, appliance standards, and other policies and programs that reduce overall gas consumption and peak loads. In addition, the planning process should be as open and transparent as possible.

The planning process should be revised to include a more critical review of new gas investments, as discussed above regarding assessment of proposed system extensions. Also, Nevada should develop a comprehensive framework for non-pipeline alternatives. Utilities should be required to provide documentation that non-pipeline alternatives were considered, including quantitative analysis of benefits, costs, and risks associated with fossil gas investment and alternatives. Specifically related to gas demand forecasting, we direct the Commission's attention to NRDC's reply comments submitted on April 28, 2021 in Docket No. 19-12019,

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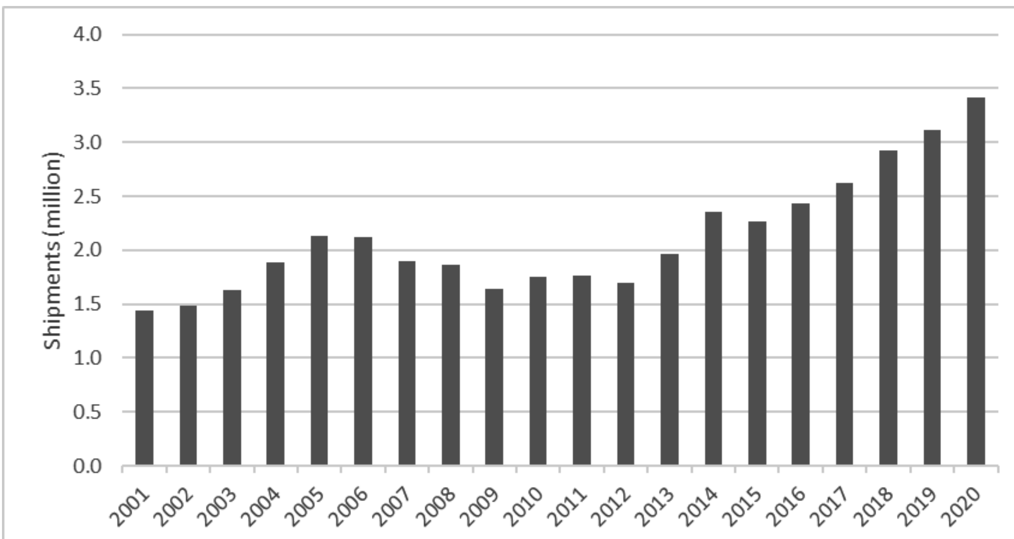
also drafted with the assistance of Synapse Energy Economics.[25]

a. What is the historical and current market share of gas appliances compared to electric appliances for cooking, water-heating, and space-heating?

Shipments of air-source heat pumps ("ASHP") have been growing over the past two decades in the U.S., particularly over the past 10 years, according to the Air Conditioning, Heating & Refrigeration Institute ("AHRI"), as shown in Figure 1. Approximately 1.7 million ASHPs were sold in 2000, nearly doubling to nearly 3.5 million by 2020.

Figure 1. Historical ASHP Shipments in the U.S., 2001-2020[26]

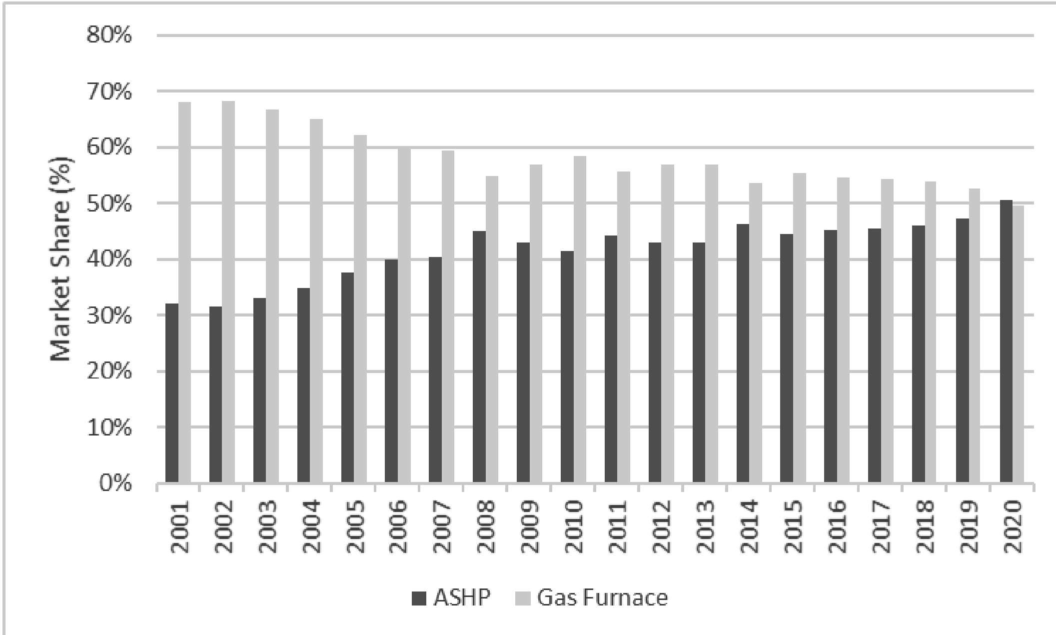


The share of ASHPs relative to gas furnaces also increased substantially over the past two decades. While the shipment increases for ASHP were much greater over the past decade than over the preceding decade, the market share for ASHPs increased continuously from 30 percent in 2001 to 50 percent in 2020, as shown in Figure 2.

[25] Investigation and Rulemaking to adopt, amend, or repeal regulations regarding review of long-term natural gas procurement practices pursuant to NRS 704.185 and 704.991 and requirements for long-term natural gas forecasting.

[26] AHRI, *Central Air Conditioners and Air-Source Heat Pumps*, accessed December 13, 2012. available at: https://bit.ly/3mejsdw

Figure 2. Historical ASHP and Gas Furnace Market Share, 2001-2020[27]



We also observed an increase in electric heating in Nevada based on the American Community Survey ("ACS") data. The ACS provides data on the number of households by fuel type for heating by state. According to the ACS, electric heating was used by about 29 percent of households in 2010 and increased to 35 percent in 2019. On the other hand, gas heating decreased from 65 percent in 2010 to 59 percent in 2019 as shown in Figure 3.

[27] *Id*. Note: the graph assumes that the share of ASHP and gas furnace equals 100 percent.

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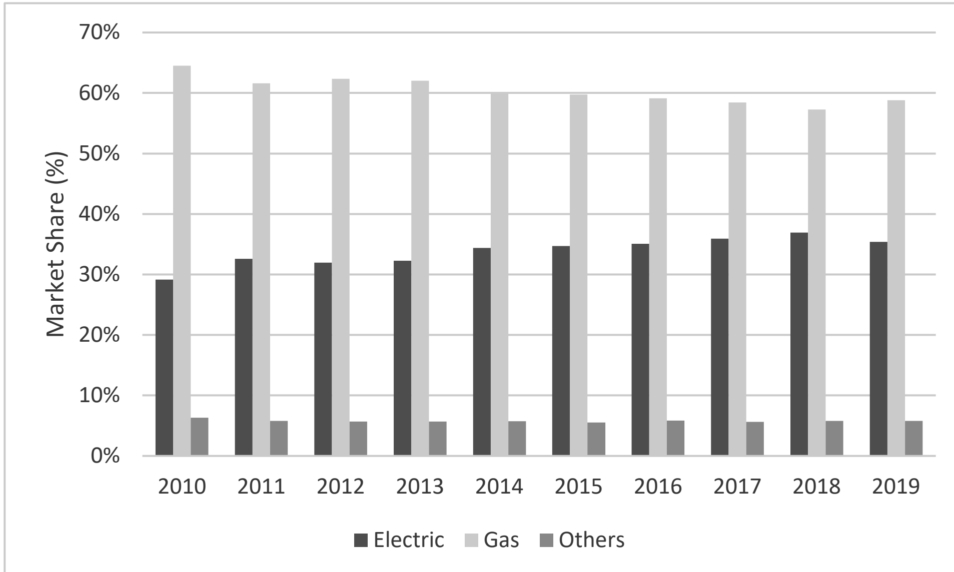
Figure 3. Historical Residential Heating Fuel Share in Nevada, 2010-2019[28]



The national market share trend for residential water heating between electric and gas has not changed as much over the past two decades, as shown in Figure 4. The share of residential electric water heating increased by just 3 percent during this period, to 50 percent in 2020. On the other hand, the share of commercial electric storage water heaters increased from just about 33 percent in 2001 to 64 percent in 2020, according to AHRI, as shown in Figure 5 below.

[28] Calculated based on U.S. Census Bureau. American Community Survey 2019 5-Year Estimates Detailed Tables, House Heating Fuel, Table B25040. Available at https://bit.ly/3GPXYve

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Figure 4. Historical Residential Water Heating Market Share, 2001-2020[29]

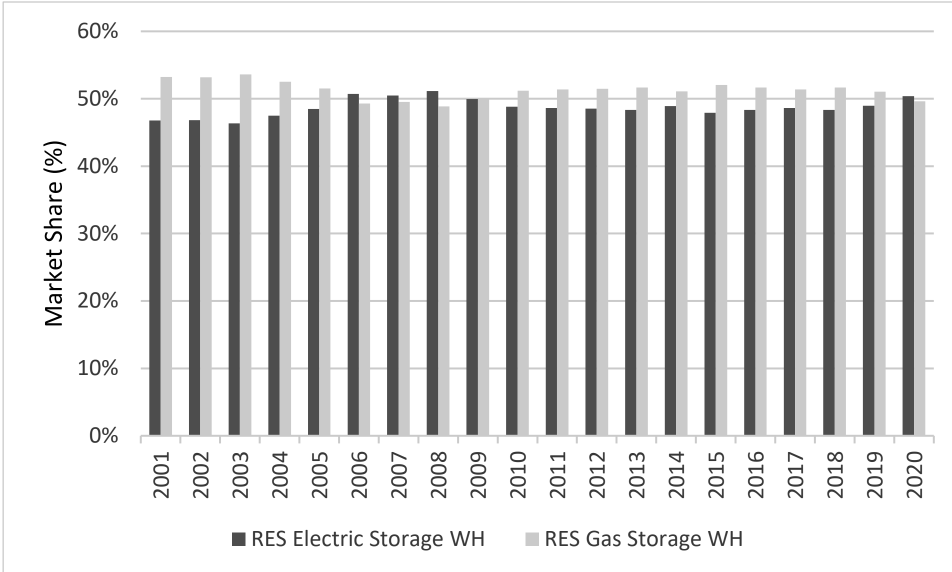
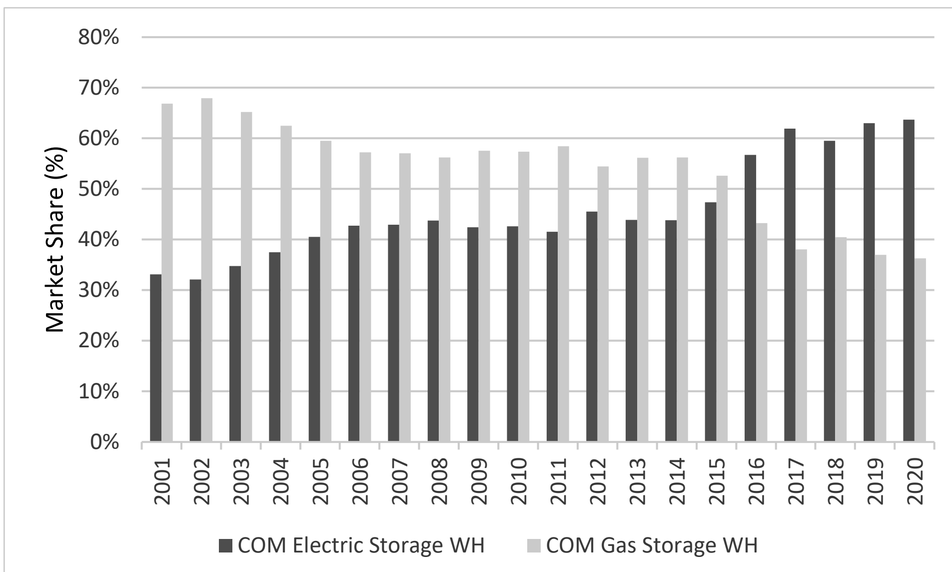


Figure 5. Historical Commercial Water Heating Market Share, 2001-2020[30]



We are not aware of any data about the share of electric vs. gas cooking equipment. As this is an area where consumers show strong preferences, we expect minimal changes on the share over the past decade or so. However, various electric cooking devices, such as induction

[29] *Id*. Note: the graph assumes that the share of electric and gas storage heaters equals 100 percent.
[30] *Id*. Note: the graph assumes that the share of electric and gas storage heaters equals 100 percent.

cooktop, air fryers, and multi-use cookers (e.g., Instant Pot) have become widely available in the market over the past few years. In addition, a growing number of studies are finding adverse health impacts of indoor air pollutions from gas cooking.[31] Thus, we expect that the share of electric cooking will grow gradually over time as consumers learn about the benefits of new electric cooking equipment and the health impacts of gas cooking.

b. Is there an identifiable, naturally-arising electrification trend? Are consumers currently buying electric appliances at regular appliance turnover points?

As discussed in our response to Question 8.a above, there's a naturally-occurring electrification trend in some end-use markets such as heating and water heating. However, there are still numerous barriers to electrification at appliance turnover points, including:

- When existing heating systems suddenly fail to operate and need immediate replacement, customers and contractors tend to replace the systems in kind and with equipment that is readily available. This is because rebate programs—a common energy efficiency program design—may not change what products distributors keep in stock. Alternate program designs, such as midstream approaches, can change distributor behavior and increase equipment availability such that electric alternatives are readily available in emergency situations.
- Some customers, such as renters, lack the ability to make changes in their buildings.
- Contractors and customers may lack knowledge of electrification technologies and their benefits, or with costs and impacts of gas equipment.

The presence of these and other barriers means that policy intervention may be necessary to support naturally-arising electrification trends.

[31] See, for example, Seals, B., Krasner, A., *Health Effects from Gas Stove Pollution* (2020) RMI, Physicians for Social Responsibility, Mothers Out Front, and Sierra Club, available at: https://bit.ly/32fnYkM

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8. Phase 3 (viii): What can and should be done for the natural gas utility's workforce if there is a transition away from natural gas service? Should new hiring be curtailed to prevent employees from becoming "stranded" with sunk training costs and limited employment options?

As the transition to a decarbonized energy sector continues, it will be important to support a "just transition" for fossil fuel workers. In the case of combined gas and electric utilities, workers on the gas side will play an important role for years to come in assisting with the coordination of fuel-switching actions and paired infrastructure investment and retirement actions. Beyond these activities, gas workers in joint operating companies should be encouraged to move within the company as opportunities requiring similar skills arise and to support the growth likely to occur on the electric side. While some training may be needed for these workers, they have valuable knowledge of the utility business to draw on.

For gas-only utilities, there may be opportunities for workers to support new business areas. For example, geothermal wells or districts may prove a natural fit for gas utilities and their workers. Some skills such as excavation and plumbing are likely applicable to other businesses as well. Training programs should be offered to refine and tailor existing skills to ease the transition to a related industry, in particular when there are no opportunities within the utility.

DATED December 17, 2021.

Respectfully submitted,

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