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GOVERNMENT OF THE DISTRICT OF COLUMBIA
OFFICE OF THE ATTORNEY GENERAL

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Public Advocacy Division
Housing and Environmental Justice Section

E-Docketed

February 12, 2026

Ms. Brinda Westbrook-Sedgwick, Secretary
Public Service
Commission of the
District of Columbia
1325 G Street, NW, Suite 800
Washington, DC 20005

Re: Formal Case No. 1167 -- In the Matter of the Implementation of Electric and Natural Gas Climate Change Proposals

Dear Ms. Westbrook-Sedgewick:

On behalf of the District of Columbia Government (DCG or "the District"), I enclose for filing a paper it commissioned authored by Current Energy Group (CEG), setting forth a gas planning framework that identifies the least-cost, least-risk set of investments, resources, and actions needed to meet all District policies, including emissions reduction targets. The paper is entitled "Evolving the District of Columbia's Gas Distribution System for a Cost-Effective Clean Energy Transition: A Framework for Long-Term Gas Utility Planning."

On December 10, 2024, the Public Service Commission ("the Commission") issued Order No. 22339 in Formal Case No. 1167, which requested initial comments on the feasibility of establishing a gas planning proceeding. On April 28, 2025, the DCG filed comments strongly supporting creating a comprehensive gas planning process. This paper takes a step further by presenting a straw proposal for a gas planning framework that that emphasizes transparency, data-driven analysis, and robust stakeholder involvement. DCG supports all the recommendations in CEG's paper and urges the Commission to act.

The Commission has made great progress in advancing Integrated Distribution System Planning for the District's electric infrastructure. The same type of planning process is now urgently needed for the District's gas distribution system. As both the affordability crisis and the climate crisis continue to worsen, it is imperative that the Commission acts now to ensure that future gas investments are prudent, cost-effective, and consistent with the District's statutory commitments to reduce emissions.

If you have any questions regarding this filing, please contact the undersigned.

Sincerely,

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CURRENT
ENERGY GROUP

Evolving the District of Columbia's Gas Distribution System for a Cost-Effective Clean Energy Transition:

A Framework for Long-Term Gas Utility Planning

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Introduction and Justification of Long-Term Gas Plan

On December 10, 2024, the Public Service Commission (PSC, or "the Commission") issued Order No. 22339 in Formal Case (FC) No. 1167, which requested initial comments on the feasibility of establishing a gas planning proceeding in the District of Columbia (DC or "the District"). On April 28, 2025, the DC Government filed comments strongly supporting creating a comprehensive gas planning process. As the District outlined in those comments, comprehensive, long-term gas planning with robust stakeholder involvement is essential to align utility investments and operations with DC's clean energy policies as well as recent market and technology trends.[1] The DC Government also argued that such a proceeding is also necessary to consolidate the many other proceedings that the Commission has established on gas investment and climate issues, such as FC 1167 (Climate Business Plans), FC 1179 (accelerated pipe replacement), FC 1178 (leak reduction) and FC 1180 (review of Washington Gas Light investments as part of rate case).[2]

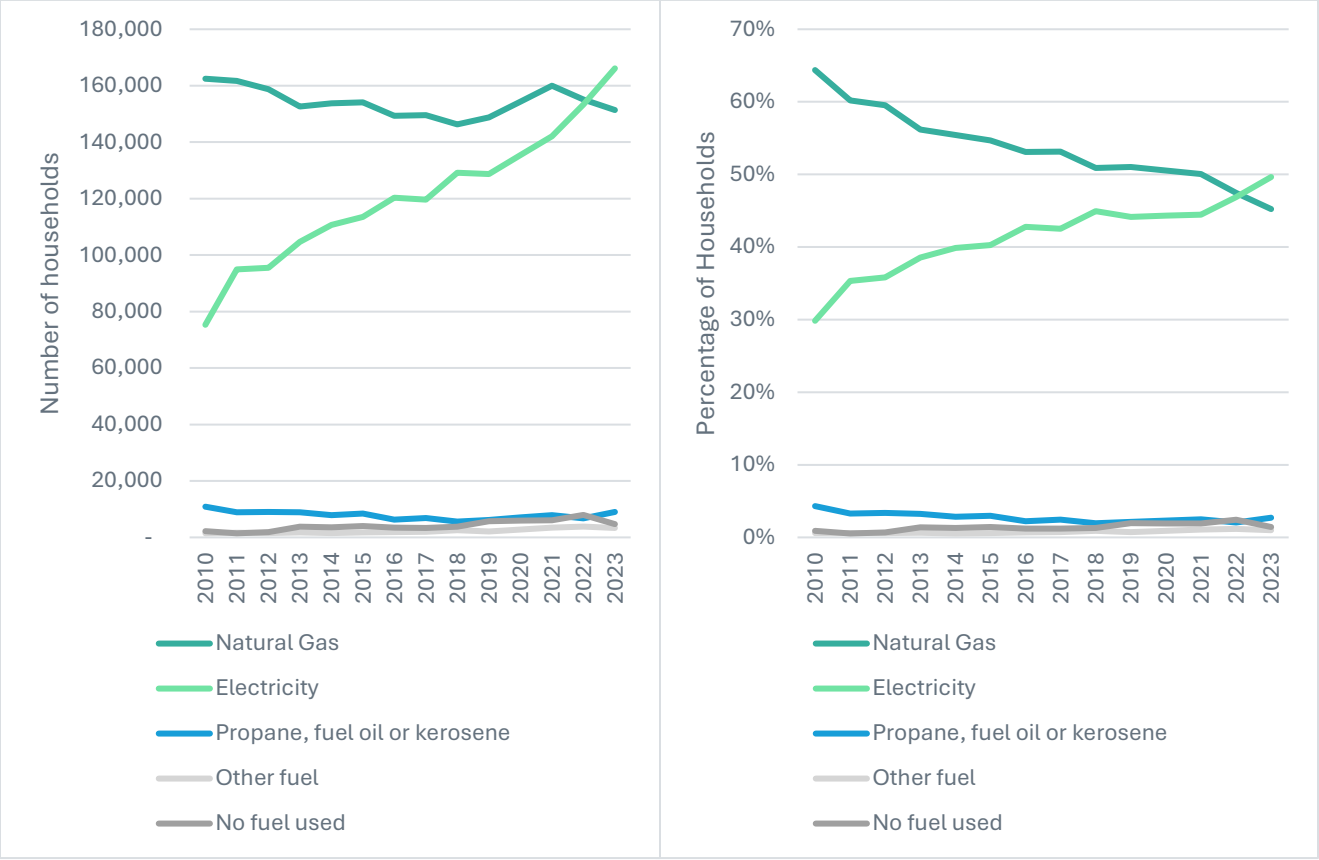
The purpose of this paper is to outline a gas planning framework that identifies the least-cost, least-risk set of investments, resources, and actions needed to meet all District policies, including emissions reduction targets. A robust planning process also helps ensure that system risks are ranked appropriately and that the gas utility focuses limited resources on "worst first" projects that are targeted to improve the safety and reliability of the gas system. This paper identifies the content and process for transparent, data-driven gas planning filings.

Comprehensive, long-term gas planning is urgent for the District given recent legislative, policy, technology, and market developments that heighten the risk for Washington Gas and Light (WGL) and their ratepayers if current gas system investment trends continue. As shown in Figure 1, the number of Washington, DC households using gas for heating has decreased by approximately 7% since 2010. As a percentage of households, the decline has been more dramatic; gas heating users have fallen from 64% of DC households in 2010 to 45% in 2023. In other words, the Company has experienced a 30% decline in its market share for space heating over the past 13 years.

Additionally, Figure 1 shows that the number of households using electricity for heating has increased by 21%. Half of DC households now use electricity as a primary space heating fuel. According to the most recent 2020 U.S. Energy Information Administration (EIA) Residential Energy Consumption Survey (RECS), 14% of DC homes used a central air-source heat pump.[3]

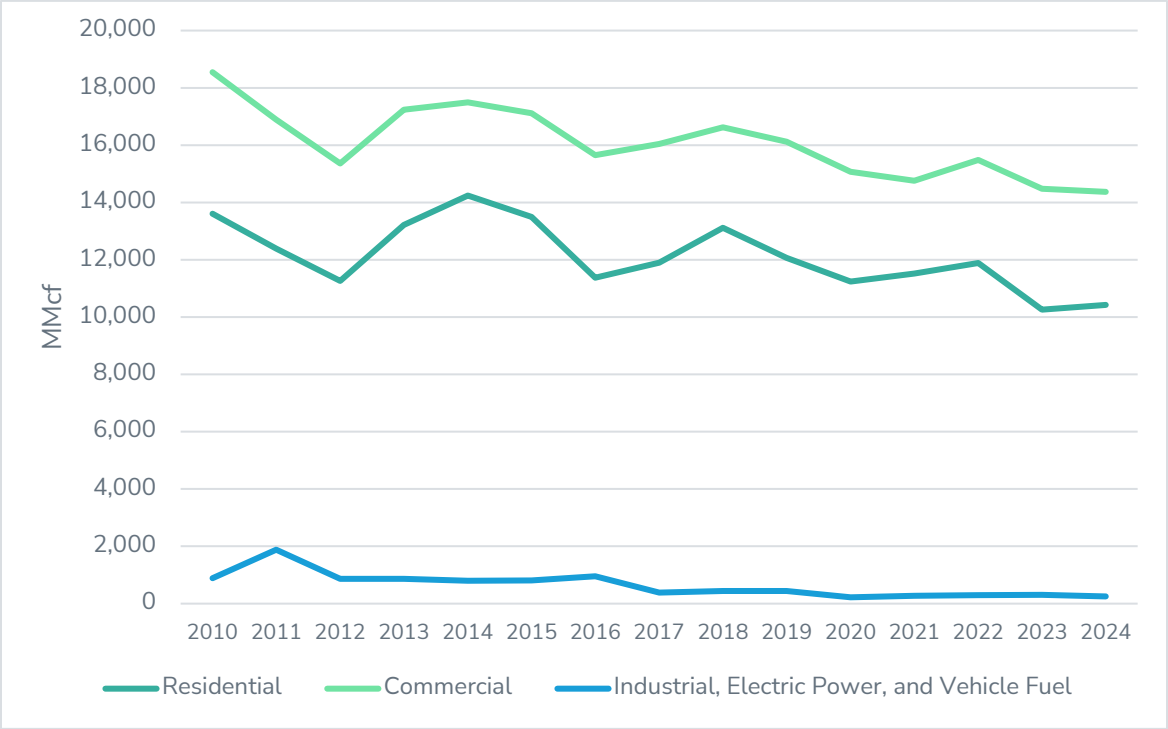
[1] FC 1167, April 28, 2025, In the Matter of the Implementation of Electric and Natural Gas Climate Change Proposals, at 3.
[2] *Ibid.*
[3] EIA, 2020 RECS, State Space Heating Highlights.

Figure 1. Household Heating Fuel in Washington, DC, 2010-2023[4]



[4] U.S. Census Bureau, American Community Survey. https://data.census.gov/table?t=Heating+and+Air+Conditioning+(HVAC)&g=040XX00US11.

Figure 2. Natural Gas Consumption by End Use in Washington, DC, MMcf[5]

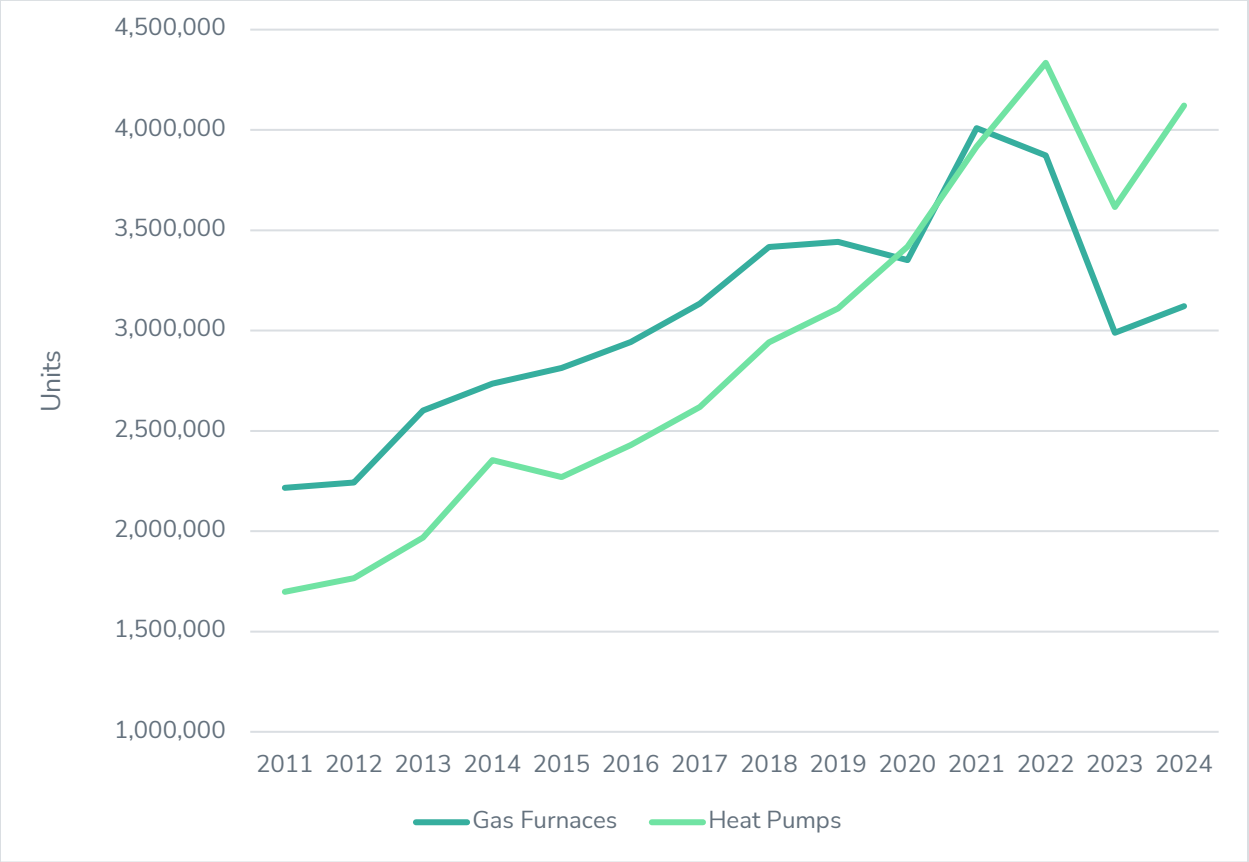


Likewise, Figure 2 above shows that residential and commercial gas consumption has fallen by about 23% in DC since 2010.[6]

The decline in the share of gas-heated households, relative to the increase in electric-heated households, reflects longstanding market and technology trends, along with policy changes in DC. These market and technology factors include the relative increase in gas rates and advances in heat pump technology. Between 2010 and 2023, residential natural gas rates in DC rose by 5.6% relative to electricity.[7] At the same time, heat pump technology has markedly improved. In 2021, the U.S. Department of Energy (DOE) launched the Residential Cold Climate Heat Pump Challenge to develop more efficient cold climate heat pumps. In November 2022, Trane, a heat pump manufacturer, announced that its newest prototype exceeded DOE targets by performing at temperatures as low as -23 degrees Fahrenheit.[8]

[5] U.S. Energy Information Administration, Natural Gas Consumption by End Use, https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SDC_a.htm.
[6] Industrial, electric power, or vehicle end uses of gas consumption are negligible.
[7] FC 1180, Direct Testimony of Asa Hopkins at 10.
[8] *Trane Passes Heat Pump Challenge*, Cooling Post (Nov. 4, 2022). https://www.coolingpost.com/world-news/trane-passes-heat-pump-challenge/.

Figure 3. U.S. Annual Sales of Heat Pumps and Gas Furnaces from 2012-2024[9]



The relative increase in electric heating and heat pumps in DC mirrors a national increase in heat pump adoption. As shown in Figure 3 above, in 2021, electric heat pump sales exceeded gas furnace sales for the first time in the U.S., and in subsequent years, the gap between the two continues to widen.

In addition, we expect recent policy developments in DC will accelerate building electrification and decrease demand for natural gas. Several of these policies are scheduled to take effect in the future and, therefore, are not yet baked into historical growth rates:

- The **Climate Commitment Amendment Act of 2022**, which sets greenhouse gas (GHG) emissions targets that the Commission's Order No. 21938 has adopted for the gas and electric utilities. The Carbon Free DC strategy and Clean Energy DC 2.0 plans outline strategies to meet

[9] "Monthly Shipments | AHRI," n.d. https://www.ahrinet.org/analytics/statistics/monthly-shipments

the targets, including phasing out the sale of fossil fuel appliances by 2035 and eliminating on-site fossil fuel combustion in buildings by 2045.[10] DC set a goal to reduce emissions:

  - 45% from 2006 levels by 2025
  - 60% from 2006 levels by 2030
  - 70% from 2006 levels by 2035
  - 85% from 2006 levels by 2040
  - Net zero by 2045.

- The **Greener Government Buildings Amendment Act of 2022** requires new or substantially renovated District-owned buildings to comply with a net-zero energy code.[11]
- The **Clean Energy DC Building Code Amendment Act of 2022** requires new or substantially renovated commercial buildings and residential multifamily buildings taller than three stories to comply with a net-zero energy standard, including a prohibition of on-site fuel combustion.[12]
- The **Building Energy Performance Standard** requires buildings over 50,000 square feet to comply with building type-specific energy use intensity (EUI) standards as of 2021. Buildings between 25,000 and 50,000 square feet will be required to comply starting in 2028, and buildings between 10,000 and 25,000 square feet will need to comply beginning in 2034.
- The **Healthy Homes and Residential Electrification Act of 2024** establishes the "Breathe Easy" residential electrification retrofit program for low- and moderate-income households.[13]

It is increasingly risky for WGL's ratepayers to accelerate spending on pipeline infrastructure that is incompatible with DC's climate policies. Taken together, the impact of DC's policies are likely to result in a continued decline in the number of buildings that use gas through 2045. Without careful planning, a decline in gas use could make gas utility capital investments more difficult to recover. Pipeline investments are typically depreciated over 35 – 60 years. If gas demand declines between now and then—as it already is in WGL's service territory—the utility will seek to recover the costs of new investments going into service today over a smaller customer base and shrinking sales.

There are two related but distinct cost pressures. First, if customers leave the system entirely, undepreciated costs, along with the costs to operate and maintain the remaining assets, will be spread over a smaller customer base. This would lead to higher costs for the remaining customers. Second, even if the number of customers remains stable due to partial or hybrid electrification, gas throughput will still decline. As fixed costs are recovered over fewer therms, declining throughput

[10] Carbon Free DC 2045 Strategy, at 24. https://sustainable.dc.gov/sites/default/files/dc/sites/sustainable/page_content/attachments/Carbon%20Free%20DC.pdf

[11] D.C. Law 24-306. Greener Government Buildings Amendment Act of 2022. https://code.dccouncil.gov/us/dc/council/laws/24-306

[12] D.C. Law 24-177. Clean Energy DC Building Code Amendment Act of 2022. https://code.dccouncil.gov/us/dc/council/laws/24-177

[13] D.C. ACT 25-488, Healthy Homes and Residential Electrification Amendment Act of 2024. https://lims.dccouncil.gov/downloads/LIMS/52291/Signed_Act/B25-0119-Signed_Act.pdf?Id=191649

will drive up the cost per unit of energy delivered. WGL is likely to seek recovery of undepreciated assets from a shrinking customer base, and over-shrinking therm sales, into the 2080s.

To prevent rising rates and stranded assets, careful and proactive gas planning is critical. Several states use gas planning to increase transparency into utility investments and to better align gas investments with state policy and ratepayer outcomes.

Gas Planning in Other States

Several states across the country have adopted gas utility planning requirements, either as a matter of good regulation or in response to declining demand, climate targets, and concerns over rising customer costs. These frameworks vary in form, ranging from integrated resource plans (IRPs) in Oregon and Washington that focus on optimizing demand- and supply-side resources, to long-term infrastructure plans in Michigan, Illinois, and Colorado, to emissions reduction and clean heat plans (CHPs) in New York, Massachusetts,[14] and Colorado. Gas utilities file various gas plans in New York, Colorado, Oregon, Washington, Nevada, New Mexico, Michigan, Missouri, Maine, Georgia, and Massachusetts, among others. Although each gas planning framework is unique, they share common elements for the most part, including a long-term demand forecast, scenario and sensitivity analysis, an evaluation of costs and risks, and a public process. More recently adopted requirements, such as those in Illinois, Washington, Massachusetts, Colorado, Missouri, and Minnesota, require gas utilities to evaluate the costs and risks of traditional infrastructure to non-pipeline alternatives (NPAs). Table 1 below summarizes components of other states' gas planning requirements.

Table 1. Comparison of State Gas Planning Requirements[15]

	New York Long-Term Plan	Oregon and Washington IRPs	Colorado Gas Infrastructure Plan (GIP) and Clean Heat Plan (CHP)	Massachusetts Climate Compliance Plans
Process Requirements				
Filing Cadence	Every 3 years	Every 2 years	GIP: Every 2 years CHP: Every 4 years	Every 5 years
Planning Horizon	20 years	WA: 10+ years OR: 20+ years	GIP: 6 years CHP: 5 years	Unspecified
Stakeholder Comments	X	X	X	X

[14] Massachusetts Department of Public Utilities Order 20-80-B.

[15] Cebulko, B, et al,; "A Regulator's Blueprint for 21st Century Gas Utility Planning," prepared by Strategen for Advanced Energy United. 2023, at 58.

	New York Long-Term Plan	Oregon and Washington IRPs	Colorado Gas Infrastructure Plan (GIP) and Clean Heat Plan (CHP)	Massachusetts Climate Compliance Plans
Technical Working Group		X		
Third-Party Evaluation	X			
Draft and Final Plan	X	X		
PUC Review	X	X	X	X
Analytical Requirements				
Near-Term Action Plan		2-4 years	GIP: 3 years	5 years
Load Forecasting	X	X	X	
Scenario and Sensitivity Analysis	X	X	X	X
Identification of Preferred Portfolio	X	X	X	X
Equity Analysis	X			Recommended
Bill Impact Analysis	X		X	
Capital Investment Forecast	X[16]		X	X[17]
NPA Analysis	X	Required by OR PUC	X	X
System Mapping		Included but not required	X	

[16] A capital investment forecast is not explicitly required in the NY PSC's gas planning order. However, a capital investment forecast is necessary for a reasonable bill impact analysis, and each of the New York gas utilities has included capital forecasts in their initial filings.

[17] Order 20-80-B requires the gas utilities to detail "the investment required" for their preferred portfolio, although none of the utilities in Massachusetts have provided a capital investment forecast in their 2025 plans.

DC is joining a growing cohort of jurisdictions requiring gas planning. Our proposal for the District draws directly from the precedent and examples from other states' planning requirements, as well as from our expertise in engaging in these plans, while tailoring the requirements to DC's unique policy landscape.

Existing Gas Planning Process in DC

A comprehensive gas planning framework would replace today's fragmented dockets with a single, transparent process that aligns WGL's investments, demand forecasts, and policy compliance under one coordinated plan.

The Commission has already established several dockets, enabling stakeholders to scrutinize aspects of the climate transition and WGL's gas expenditures. However, these dockets are not explicitly coordinated, and none currently offer a holistic view that connects the Company's long-term capital plan, specific planned investments, and the likely trajectory of demand in WGL's service territory, given market and policy trends.

WGL's 2020 Climate Business Plan and 2025 15-Year Plan are not aligned with DC's climate strategy, as outlined in the Carbon Free DC strategy and Clean Energy DC 2.0 plans. Furthermore, we are unaware of any current requirement for WGL to evaluate NPAs to planned capital investments, meaning that there is no mechanism steering the Company away from investments that risk becoming stranded in 20 years.

As the Department of Energy and Environment (DOEE) noted in its comments on April 28, 2025, in FC 1167, the current dockets are substantively interrelated but procedurally separate.[18] FC 1167 covers Climate Business Plans (CBPs) and WGL's 15-year plan; FC 1178 and 1179 cover WGL's most recent accelerated pipe replacement plan and leak reduction practices; and FC 1180, WGL's most recent rate case, covers a prudence review of WGL's investments. However, none of these plans constitute a long-term gas plan. WGL's accelerated pipe replacement plan does not plan specific investments well in advance of their need, and as a result, WGL does not give customers more than two years of advance notice that their service line is scheduled to be replaced.[19] This short-term framework does not account for how investments need to adapt to mitigate future risks, nor does it consider transitioning to lower-risk alternatives in the medium to long term.

WGL's CBP and 15-year plan also do not align the Company's gas investments with its long-term climate targets. In the five years since WGL filed its first CBP, the Commission has yet to approve a long-term climate plan. Both plans largely overlook electrification as a climate compliance option and assume that carbon offsets will comprise the bulk of the Company's climate strategy.[20]

[18] FC 1167, DOEE Comments, April 28, 2025, at 3.
[19] FC 1179, Hopkins Direct Testimony at 46.
[20] FC 1167, WGL 15-Year Plan at 48, Figure V-4.

This assumption contrasts sharply with the DC government's Carbon Free DC strategy, which envisions phasing out the sale of fossil fuel appliances by 2035 and fossil fuel combustion in buildings by 2045.[21] The assumption that natural gas will continue to be used at current levels contrasts sharply with recent trends, where electricity has overtaken natural gas as the predominant space heating fuel in DC.

Our proposal, as outlined below, attempts to rectify the gaps in WGL's previous climate and gas infrastructure planning efforts. The primary purpose of our proposed long-term gas plan straw proposal is to identify and subject to intervenor scrutiny a least-cost, least-risk portfolio of investments and actions that are robust to various gas demand and policy futures. The proposal aims to move beyond business as usual and grapple with the potential impacts of continued large-scale spending on pipelines on ratepayers in a highly electrified future. The proposal folds related proceedings, such as the accelerated pipe replacement proceeding, into one consolidated docket with clear linkages between DC's long-term strategy, WGL's investments, and ratepayer outcomes. The proposed process also would solicit expert stakeholder feedback throughout development of the gas plans, in contrast to current planning processes that are entirely utility-led.

Lastly, one of the primary benefits of a gas plan is that it serves as a single repository of critical utility information that is available to the Commission, stakeholders, and the public at large.[22] Our proposed framework establishes a comprehensive gas planning framework that will provide all parties with a coordinated repository of information, linking WGL's long-term capital plans, projected demand, and policy compliance in a single proceeding.

Below, we lay out our recommended process and analytical requirements for a long-term gas plan.

Long-Term Gas Plan Straw Proposal

Regulatory Process of Long-Term Gas Plan

The regulatory and public process that guides long-term gas planning is crucial for ensuring that utility investments and actions align with policy objectives and customer interests. The imperative process also provides transparency between the utility, ratepayers, and the public. The people affected by utility decisions, ratepayers, and the broader public should both have a voice in shaping these plans and access to the information needed to understand them.

Stakeholders must have opportunities to provide feedback on the gas utility's planning in advance of the litigated filing, at which point the utility's application is likely to be fully baked with few avenues for iteration.

[21] The Commission has previously recognized the Clean Energy DC plan as the District's primary climate and clean energy roadmap, stating, "[a]t the outset, we recognize that multiple roadmaps for moving forward . . . have the potential of creating unnecessary confusion and are not in the public interest. We agree with Sierra Club that the Clean Energy DC Plan is the District Government's roadmap for achieving the District's climate goals."11 F.C. 1167, Order No. 20754, 43 (rel. June 4, 2021).

[22] Cebulko, B, et al,; "A Regulator's Blueprint for 21st Century Gas Utility Planning," prepared by Strategen for Advanced Energy United. 2023, at 58.

A well-structured cadence and stakeholder process is essential to ensure the long-term gas plan remains transparent, adaptive, and aligned with District policy. We recommend the following framework:

Cadence

- The long-term gas plan should be filed at least once every three years. A three-year cadence enables the utility's planning to adapt to changing conditions, while also avoiding undue administrative burden.
- The first plan should be filed by January 1, 2027, or within 365 days of a Commission decision establishing a long-term gas planning requirement, whichever is later.
- Prior to the plan filing, there should be a robust stakeholder process. The stakeholder process is necessary to facilitate alignment of the long-term gas plan with the city of DC's broader climate strategy.

Stakeholder Process

The stakeholder process should be a formal component of the Commission's gas planning docket, subject to the Commission's rules for docketed proceedings, rather than an informal utility engagement. The Commission should require the following elements to ensure transparency, fairness, and accountability:

- **Workplan:** One year in advance of the plan filing, WGL should file a workplan that identifies the number of stakeholder workshops to be held, workshop dates, and the content of each workshop.
- **Public Workshops:** WGL should be required to hold at least six to eight workshops in advance of plan filing, facilitated by a third-party facilitator.
    - At least one of these workshops should solicit stakeholder input on scenarios to be modeled as part of the plan.
    - Presentation materials should be made publicly available five business days in advance of each workshop.
    - Following the workshop, WGL should allow at least 10 business days for stakeholders to submit written comments to the Company. Stakeholders may also file information requests on the presentations, which the Company should respond to within five business days.
- **Draft Plan:** WGL should present a draft plan for stakeholder comment at least 90 days before filing the final plan. Stakeholders should be given at least 20 business days to provide comments on the draft plan to the Company. Stakeholders may also file information requests on the presentations, which the Company should respond to within five business days.

- **Stakeholder Participation Documentation**: The final plan should include an appendix listing all stakeholder recommendations received through workshops and on the draft plan, whether written or provided in person, along with the Company's response and justification for any recommendations not adopted.

Commission Review and Approval

To the extent that the plan relies on confidential data, the Company must make assumptions, inputs, and outputs available to intervenors in the plan proceeding under a non-disclosure agreement in native formats.

In determining whether to approve, deny, or approve with modifications WGL's plan, the Commission's evaluation should include, but not be limited to, the following:

- Whether the plan satisfies all filing requirements; satisfying the filing requirements should be necessary but not sufficient for the Commission to approve the plan
- Whether the Company adequately responded to and incorporated stakeholder feedback
- The methods and processes used to create the plan, including the adequacy of the Company's forecasting and alternatives evaluation
- Whether the inputs, assumptions, and methodologies are transparent, supported by evidence, and consistent with Commission precedent, industry standards, and best practices
- Whether the plan's modeled outputs are internally consistent, transparently derived, and reasonably supported by the record
- Whether the investments detailed in the approved plan are least-cost and least-risk according to evidence in the record

The Commission may grant a presumption of prudence for investments detailed in the plan if the Commission determines that the record supports the reasonableness of the investment and the evaluation of alternatives. If the Commission denies WGL's gas plan, WGL must file an amended plan in response to the Commission's decision within 60 days.

Long-Term Planning Case Study: Xcel Colorado 2024-2028 Clean Heat Plan

Colorado requires two complementary types of gas plans:

- **Clean Heat Plans (CHPs):** Every five years, gas utilities must file long-term CHPs to meet statutory greenhouse gas emissions targets, starting with a 4% greenhouse gas reduction target from 2015 levels by 2025 and a 22% reduction target by 2030. Utilities may meet these emissions reduction targets by deploying resources, including beneficial electrification, energy efficiency, renewable gas, and green hydrogen. The CHPs must also project long-term sales, customer count, system-wide design-day demand, resource portfolios, and emissions trajectories through 2050 or for a 20-year period, whichever is greater.[1]
- **Gas Infrastructure Plans (GIPs):** Additionally, the utilities must file short-term GIPs every two years, detailing the new business, capacity expansion, and system safety and integrity investments required within the next six years. The gas utilities must analyze NPAs for planned projects above a certain dollar threshold, currently set at $3 million for Xcel, the state's largest utility.[2]

In 2023, Xcel filed its first CHP, which proposed portfolios through 2028 for meeting the 2030 emissions reduction targets. In its initial plan, the utility proposed a preferred portfolio incorporating a mix of beneficial electrification, energy efficiency, renewable gas, and green hydrogen. Xcel also proposed to obtain roughly a third of the required emissions reductions from certified gas and carbon offsets. The Company withdrew the certified gas and carbon offset proposals after intervenors filed a motion arguing that those two pathways were not compliant with the law.[3]

During the evidentiary hearing, the Colorado PUC issued a bench order requiring Xcel to submit new modeling results using revised assumptions regarding the cost and scalability of beneficial electrification, as well as a revised cost-benefit analysis incorporating the Utility Cost Test. In its 2024 decision, the Colorado PUC approved a modified clean heat resource portfolio based on the bench order modeling, which included a significantly greater share of electrification and efficiency than Xcel had originally proposed. The PUC also approved NPAs for two gas infrastructure projects, the Pearl Street Mall main replacement project and the Aurora F-3 capacity expansion project, which had been rolled over from Xcel's 2023 GIP.[4]

[1] Proceeding 21R-0449G, Decision C22-0760A, Attachment A.
[2] *Ibid.*
[3] Proceeding 23A-0392EG, Hrg. Ex. 114, Verified Amendment to Application
[4] Proceeding 23A-0392EG, Decision C24-0397

Contents of Long-Term Gas Plan

The long-term gas plan should provide a structured, transparent foundation for evaluating the utility's future under multiple demand and policy scenarios. Each element of the plan—demand forecasting, capital and operating expenditure plans, depreciation and stranded-asset analysis, etc.—serves to connect investment decisions to the District's climate commitments, customer affordability, and maintaining a safe and reliable system. Taken together, these requirements enable the Commission and stakeholders to assess whether the Company's proposed investments and actions represent a least-cost, least-risk pathway across a range of possible demand and policy futures.

Forecasts and Analyses Planning Horizon

All forecasts and analyses, unless otherwise stated, should use a 20-year planning horizon. A 20-year outlook enables the Commission and stakeholders to compare scenario and sensitivity results on a consistent basis and on a timeline aligned with the District's policy goals.

While the planning horizon should extend 20 years, the Commission does not need to assign equal weight to all years of the forecast. Near-term results (years 1–5) should generally carry greater weight in evaluating the reasonableness of proposed actions, since those outcomes are more certain and immediately relevant to ratepayers. The mid-term years (years 3–10) are also critical, as they provide a realistic window for identifying, designing, and implementing NPAs if those prove more cost-effective than traditional infrastructure.

At the same time, maintaining a longer-term outlook (years 10–20) is essential for understanding how trends and trajectories evolve under different policy and market futures. A 20-year planning horizon encompasses the period through 2045, by which the District is required to achieve a net-zero GHG emissions target, enabling the Commission and stakeholders to evaluate how customer demand is likely to change as policies take effect toward achieving this target. This longer view is also particularly important for gas infrastructure, where pipelines and related assets have service lives spanning multiple decades and may remain in rate base long after demand has begun to decline.

Demand Forecast

The demand forecast serves as the basis for utility planning, informing supply requirements, capacity needs, and planned investments. A utility's demand forecast must be conservative enough that it can meet demand on the coldest days of the year, but not so conservative that it unnecessarily siphons ratepayer dollars to overbuild its system. The utility must also forecast demand enough in advance to address future constraints in a least-cost, least-risk manner.

We propose that the gas utility must model a range of long-term demand forecast scenarios over the 20-year planning horizon. Each demand forecast scenario must project design-day peak demand, monthly throughput, customer count, and system-wide Scope 1 and Scope 3 GHG emissions, by customer class. The demand forecast must also contain the following key components.

Design-Day Criteria

As part of each forecast, the gas utility will identify its design-day temperature and the criteria used to establish it, and provide a detailed description of the methodology used to calculate or derive the design-day. In addition to historical weather records, the methodology should reference relevant

climate science to assess whether long-term warming trends or changing weather variability may affect peak demand assumptions over the 20-year planning horizon.

Scenarios and Sensitivities

Utility planning under conditions of policy change and market uncertainty requires more than a single set of forecasts and assumptions about the future. Scenario and sensitivity analysis are necessary to test how investments perform across a range of plausible futures, including different levels of demand, prices, and policy ambition. Scenarios, in particular, bookend the range of future uncertainty. By comparing utility investments under multiple scenarios and sensitivities, regulators and stakeholders can evaluate whether the proposed portfolio is robust, least-cost, and least-risk, rather than optimized only for a single set of assumptions.

Scenarios

The plan must include at least four scenarios: one developed by the Company and the remaining three developed by a third party hired by the Commission. All scenarios must reflect current municipal and federal laws and policies that directly impact gas demand, as well as market trends.

In coordination with the Company's workplan filing, the Commission should issue a Request for Proposals (RFP) for a third-party consultant, overseen by Commission Staff, to design at least three additional scenarios. Other states, such as New York, have used Commission-hired consultants to broaden scenario development. Those consultants use input from the stakeholder process to inform their inputs and assumptions.

At a minimum, the third-party scenarios should include Baseline Scenario, a Climate Policy Scenario, and at least one scenario developed using a set of assumptions from WGL stakeholders.

Baseline Scenario

The purpose of the Baseline Scenario is to establish a reference case reflecting current laws, policies, and market conditions.

Requirements:

The Baseline Scenario must account for all current municipal and federal laws and policies that directly impact gas demand, as well as market trends. The Baseline Scenario must account for market electrification, based on historical trends in heat pump and gas appliance sales, as well as forecasted rates and the price elasticity of demand. The third-party consultant must coordinate with stakeholders prior to filing the plan to ensure that it accurately characterizes current DC policies.

The first plan's Baseline Scenario must incorporate the following laws and policies:

- Current building codes and performance standards, including:
    - 2022 Greener Government Buildings Amendment Act, which establishes a net-zero energy standard for all commercial buildings and residential buildings taller than three stories.
    - The District Building Energy Performance Standard
    - Clean Energy DC Building Code Amendment Act of 2022
    - Healthy Homes and Residential Electrification Act of 2024

- All current DC Sustainable Energy Utility (DCSEU) energy efficiency and electrification programs and targets

Subsequent plan Baseline Scenarios should account for the changing laws and policies that occurred since the previous plan.

Climate Policy Scenario

The purpose of the Climate Policy Scenario, or scenarios, is to ensure that the planning aligns with the District's broader climate strategy.

Requirements:

The third party, in consultation with the DC DOEE, should develop the assumptions for the climate policy scenario. The climate policy scenario(s) must model a pathway for the gas utility to meet all DC emissions targets for its Scope 1 and Scope 3 emissions. These targets include:

- The 2045 net-zero target and all interim targets contained within the 2022 Climate Commitment Amendment Act, which the Commission's Order No. 21938 has adopted for the gas and electric utilities:
    - 45% from 2006 levels by 2025
    - 60% from 2006 levels by 2030
    - 70% from 2006 levels by 2035
    - 85% from 2006 levels by 2040
- Net zero by 2045
- All targets within the Carbon Free DC strategy and Clean Energy DC 2.0 plans

Assumptions:

No less than 270 days prior to the plan filing deadline, the third party and DOEE shall provide WGL with a set of assumptions reflecting the DC Government's climate strategies and roadmaps for achieving the above statutory targets. These assumptions may include, but are not limited to:

- Residential and commercial building appliance sales and stocks in each year,
- Number of new and existing buildings fully electrified in each year, and
- Building envelope assumptions for new and existing buildings, to reflect anticipated building codes to be promulgated under DC's climate strategy.

Stakeholder Developed Scenarios

The purpose of the Stakeholder Developed Scenarios is to ensure that the long-term gas plan incorporates a scenario that reflects the perspectives and priorities of non-utility parties.

Requirements:

The third party must solicit responses and, from those responses, develop at least one coherent scenario that is differently situated than any other scenario and represents the perspectives and priorities of non-utility parties. The third party must document the process for soliciting stakeholder input and provide a summary of the assumptions used, with an explanation of how competing or

conflicting proposals were reconciled. The third party may recommend up to three additional scenarios.

Sensitivities

A sensitivity is a variation of a single input variable designed to test how planning results change when that variable is adjusted. While scenarios reflect a set of assumptions and inputs about policy or market futures, sensitivities isolate the impact of uncertain variables (e.g., fuel prices, or technology adoption, etc.) on system needs and costs. By modeling sensitivities, the Commission and stakeholders can assess whether proposed investments are robust to changes in critical drivers and avoid strategies that only perform well under a single set of assumptions.

Requirements:

Both the Company and the third-party consultant may develop sensitivities for modeling in the gas plan.

- Each proposed sensitivity must be limited to variation in a single input variable.
- The Company and third party must model sensitivities across all the scenarios.
- The third-party consultant must take into consideration non-utility party requests for sensitivity analyses.
- For each proposed sensitivity, the Company and the third party must provide documentation describing the rationale, assumptions, and range of values selected.
- The number of sensitivities should strike a balance: enough to provide robust insight into the resilience of proposed investments, but not so many as to impose an unreasonable modeling burden.

Scenario Planning Case Study: Pacific Northwest Gas Integrated Resource Plans[1]

Both Oregon and Washington State require gas utilities to file IRPs that evaluate demand- and supply-side resources under multiple load scenarios and sensitivities. A key feature of both states' requirements is that the gas utilities must model compliance with statutory GHG emissions reduction targets. Oregon requires compliance with the Climate Protection Program, a cap-and-trade program with an emissions reduction target of 50% by 2035 and 90% by 2050. Washington requires utilities to model compliance with its Climate Commitment Act, a cap-and-reduce emissions program that establishes a 95% emissions reduction target by 2050.

For example, Northwest Natural's 2022 Gas IRP used a cost-optimization model, along with Monte Carlo simulations, to test nine scenarios. These scenarios incorporated different portfolios of electrification, demand-side management, and alternative fuels, as well as potential policies such as a moratorium on new gas customer connections. The IRP produced outputs on resource cost, demand, and deployment of demand- and supply-side resources under each scenario.

[1] Cebulko, B, et al,; "A Regulator's Blueprint for 21st Century Gas Utility Planning," prepared by Strategen for Advanced Energy United. 2023, at 40-41.

Capital Plan

The capital plan provides a long-term forecast of the utility's infrastructure investments, showing how spending will be allocated across categories such as safety, reliability, capacity, and new customer connections. Its purpose is to provide regulators and stakeholders visibility into upcoming investments, the underlying drivers of the investments, and their potential rate impacts.

The gas utility should outline the capital investments it requires to maintain safe and reliable service under each scenario or sensitivity. The capital forecast should project the utility's overall spending by investment category and provide more detailed information on specific known planned projects.

We propose that the gas utility provide a 20-year forecast of total capital spending for each scenario and sensitivity included in the Company's demand forecast. The 20-year capital forecast is for planning purposes, with the understanding that the forecast may change over time, especially in the out years of the planning horizon. A 20-year planning horizon encompasses the period through 2045, by which the District is required to achieve a net-zero GHG emissions target, enabling the Commission and stakeholders to evaluate how customer demand is likely to change as policies take effect toward achieving this target. A long-term capital planning horizon will provide the Commission and intervenors with visibility into how investments and associated ratepayer impacts might evolve under multiple scenarios as the District progresses toward its 2045 GHG target.

We acknowledge that the gas utility is unlikely to have visibility into individual planned projects in the second half of the 20-year planning horizon. However, the utility needs to identify investment categories and discrete investments to the extent that they are known, so that the utility, the Commission, and intervenors in the long-term gas planning proceeding can evaluate those investments in advance. This is particularly important for projects that may be a cost-effective candidate for NPAs, as described in the "Non-Pipeline Alternative Analysis" section.

Requirements:

The gas utility shall provide its 20-year capital investment forecast for each scenario and sensitivity.

- The capital forecast will be subdivided by investment category (e.g., new business, capacity expansion, system safety and integrity, mandatory relocation). Subdivision by investment category is necessary to show the drivers of gas system investment under various demand scenarios, including scenarios where demand decreases from current levels.
- For each year of the planning horizon, the capital forecast will project the following:
    - Number and cost of miles of main added
    - Number and cost of service lines added
    - Number and cost of miles of main replaced
    - Number and cost of service lines replaced
    - Number and cost of miles of main retired without replacement
    - Number and cost of service lines retired without replacement

Operational Expenditure Plan

An operational expenditure (OPEX) plan provides transparency into expected spending on activities such as system operations, maintenance, customer service, and administration. Aligning the OPEX plan with the capital plan and long-term scenarios allows the Commission and stakeholders to assess the full cost of service and evaluate how operational needs may change as the gas system transitions.

Requirements:

- The gas utility will provide its OPEX investment forecast for each scenario and sensitivity over the planning horizon, aligning with the Company's demand forecast and capital plan.
- The OPEX forecast will be subdivided by investment category.

Resource Plan

The resource plan shall present a unified assessment of both supply-side and demand-side options available to meet forecasted gas demand under each scenario and sensitivity. The purpose is to identify a least-cost, least-risk portfolio of resources that reliably meets customer needs while remaining aligned with the District's climate commitments.

The plan must evaluate how both supply and demand-side options can evolve over time as building electrification, efficiency programs, and other trends reduce throughput and reshape peak demand. The analysis should demonstrate whether regional pipeline capacity, storage, or peaking resources are necessary, or whether demand-side measures and NPAs can defer or avoid new supply investments.

Requirements:

- **Supply-Side Resource Assessment**: The utility should assess the cost, risks, and availability of firm and interruptible pipeline capacity, storage, peaking contracts, spot purchases, and any alternative fuel supply. Each resource must be described in terms of cost, contract length, flexibility provisions, and risk of underutilization.
- **Demand-Side Resource Assessment**: The utility should assess the cost, risks, and availability of energy efficiency, electrification, demand response, targeted load reductions, and NPAs. Each resource must be evaluated for potential to reduce system demand, defer capacity needs, and lower costs.
- **Integrated Evaluation**: The utility must show how combinations of supply- and demand-side resources can meet design-day and annual requirements. The evaluation must identify portfolios that minimize stranded asset risk, reduce exposure to volatile gas prices, and advance compliance with District emissions targets.
- **Comparative Portfolio Analysis:** For each demand forecast scenario and sensitivity, the utility shall present a comparative evaluation of portfolios that integrate supply-side and demand-side resources.

Non-Pipeline Alternative Analysis

To promote a least-cost, least-risk strategy for meeting customer demand, the long-term gas plan must incorporate a comparative evaluation of traditional infrastructure investments and NPAs. An NPA analysis compares the costs and benefits of pipeline projects with portfolios of demand- and supply-side resources that can reduce or avoid the need for new infrastructure. Other states, including New York, Colorado, and Massachusetts, already require such evaluations.

An NPA can be any resource or portfolio of resources capable of meeting customer demand on a peak design day that can be deployed either to avoid building out pipeline capacity or to enable the gas utility to retire an asset or set of assets in lieu of repair or replacement. NPAs can be deployed individually or in tandem with one another to avoid a particular pipeline investment. Pipeline repair can also be combined with NPAs as part of an overall strategy to maintain a safe and reliable system until customers can be converted and sections of pipes can be decommissioned. Examples of NPAs are outlined in Table 2.

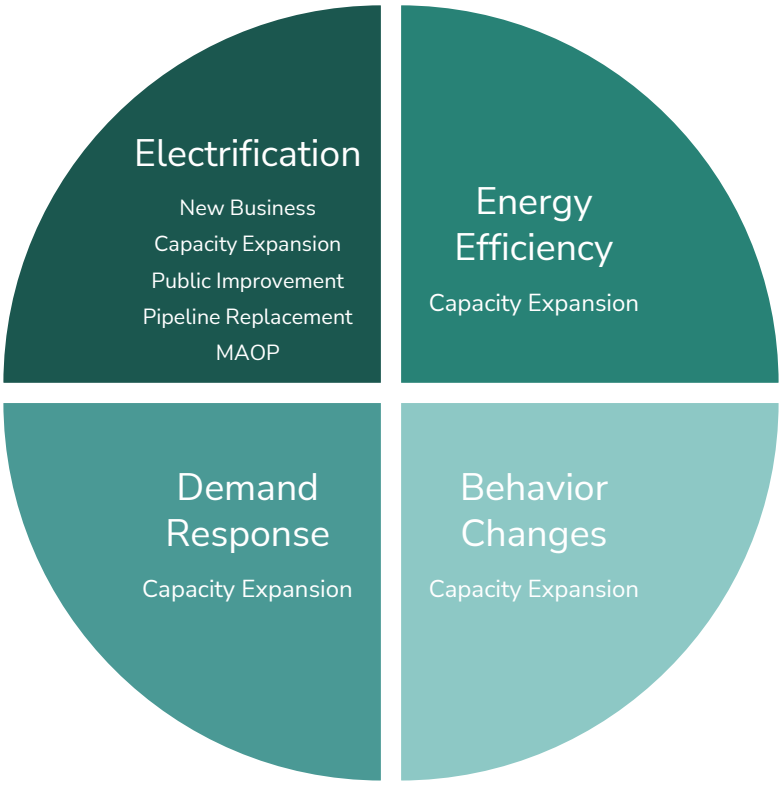
Table 2. Examples of Non-Pipeline Alternatives to Pipeline Investments

Demand-side NPAs	Supply-side NPAs[23]
Targeted electrification	On-system liquefied natural gas peaking storage
Targeted energy efficiency	Compressed and liquefied natural gas trucking (virtual pipelines)
Targeted demand response and interruptible tariffs	Propane air peak shaving
Thermal storage	On-system storage
Behavior change	
Networked geothermal	

Different NPA resources are best suited to different types of pipeline investments. For example, to avoid a pipeline replacement, the utility must enable customers taking service from the affected segment of pipe to meet their entire heating demand through an alternative energy source. In practice, the utility must fully electrify all customers taking service from the affected segment so that the segment can be decommissioned. On the other hand, the utility can avoid a capacity expansion project through several types of NPAs, such as by simply reducing demand on affected portions of the system. Therefore, any of the demand- and supply-side resources listed in Table 1 can be used as part of a portfolio to avoid a capacity expansion project. Figure 4 summarizes key demand-side NPA resources and the types of pipeline investments that they are suited to avoid.

[23] We see limited potential for supply-side NPAs in DC due to the lack of capacity expansion investments required in this service territory.

Figure 4. Capital Project Types Suited to Demand-Side Non-Pipeline Alternative Resources[24]



Typically, the utility analyzes the costs and benefits of NPA portfolios in comparison to traditional pipeline investments to select the portfolio that maximizes net benefits for ratepayers. Approaches vary by jurisdiction: the New York Public Service Commission requires utilities to use the Societal Cost Test (SCT) to evaluate NPAs, while the Colorado Public Utilities Commission requires a "modified" Total Resource Cost (mTRC) test that accounts for the social cost of carbon and social cost of methane.[25] Although there is no fixed way to conduct a cost-benefit analysis of NPAs, states with emissions-reduction targets generally treat it as best practice to use a cost test that accounts for the emissions benefits of NPAs. Generally, these jurisdictions use the same cost test for NPAs that they use for other energy efficiency and demand-side management programs. The cost-benefit test should also account for additionality, isolating the costs and benefits attributable to the NPA from the costs and benefits that would have occurred even in the absence of the NPA due to other market and policy drivers.

[24] Strategen, "Non-Pipeline Alternatives: A Regulatory Framework and a Case Study of Colorado," prepared for Lawrence Berkeley National Laboratory, at 20.
[25] *Id.* at 26.

While cost tests vary by state, the District should avoid adopting the ratepayer impact test (RIM) for evaluating NPAs. The RIM test is unique among cost-effectiveness tests in that it counts lost utility revenue as a cost. Lost revenue reflects recovery of prior system investments rather than an incremental cost associated with the NPA. For this reason, it is more appropriate for cost-benefit analysis to focus on incremental costs and benefits. This is especially true in the District, where emission-reduction goals require careful evaluation of alternatives that reduce gas consumption. By treating lost revenue as a cost, the RIM test effectively biases results in favor of system expansion and against NPAs that lower gas demand.

Requirements:

Below, we present our proposed NPA analysis straw proposal for DC. As an overarching recommendation, we suggest that the Commission adopt as much detail as possible on the NPA framework in its gas planning rules. Our experience in other jurisdictions has been that NPA evaluations, particularly the cost-benefit analysis of NPAs, tend to be heavily litigated in plan proceedings. There is often significant disagreement among utilities and intervenors regarding the cost tests, methodologies, and assumptions that the utility should use for evaluating NPAs. Developing the NPA framework beforehand, as part of the long-term gas plan rulemaking, can help avoid time-consuming future litigation.

- **Scope:** The gas utility must present an NPA analysis for all known pipeline projects that are anticipated to begin construction within 10 years of the plan filing. These include, but are not limited to,
    - All projects within the Company's comprehensive LPP remediation plan
    - All individual projects and project categories identified in the Company's capital investment plan
    - All projects for which the Company plans to seek a certificate of public convenience and necessity
    - The gas utility must conduct an NPA analysis before it seeks cost recovery for any project
- **Eligible NPAs:** Alternatives may include electrification, efficiency, demand response, thermal energy networks, thermal storage, and any other measure that reduces or eliminates the need for pipeline infrastructure investment, so long as the overall NPA portfolio does not increase GHG emissions.
    - The Commission has determined that it cannot order the gas utility to cease providing natural gas service (Order 21593). Still, it retains the authority to require comparative analysis of NPAs to optimize the utility's investment in its system.
    - WGL already contributes ratepayer funds to DCSEU, which the gas utility itself describes as "purely an electrification fund."[26]

[26] The Gas Utility, June 26, 2025. Comments in FC 1167, at 5.

If the Commission approves an NPA that includes voluntary targeted electrification, WGL must coordinate with DCSEU to implement the NPA. DCSEU shall implement the targeted electrification measures, and the gas utility shall retire the gas pipe if and when the segment is successfully electrified.

- **Benefit-Cost Analysis:** The gas utility must present a benefit-cost analysis (BCA) for all potential NPAs.
    - All NPA BCAs must comply with Order 21938 and the BCA framework adopted by the Commission, when it is complete.
    - Avoided costs of the traditional pipeline project must be treated as a benefit of the NPA.
    - To mitigate administrative burden, the utility may present an initial BCA screen in spreadsheet format with standardized cost assumptions and perform a more detailed BCA for projects that pass the initial screen.
- **Programmatic NPAs:** The gas utility must develop and implement programmatic NPA approaches for identifying situations where NPAs are likely to be the least-cost, least-risk option for meeting customer needs, such as for common, standardized categories of projects (e.g., new business requests, service line replacements, meter replacements).
    - This approach should draw on established energy efficiency program design principles, where measures meeting defined cost-effectiveness thresholds are deemed cost-effective and deployed without requiring case-by-case economic analysis.
    - At a minimum, WGL must provide a service line replacement program offering customers incentives to fully electrify rather than having their service line replaced. Service replacements account for over half of WGL's overall pipe replacement budget[27] and cost an average of $35,300[28] per line, compared with $10,000 and $30,000 to fully electrify a single-family home in DC.[29]
    - WGL must coordinate with DCSEU to offer enhanced incentives for electrification to customers requesting a new business extension.
- **Coordination with Electric System:** Each long-term gas plan must describe the gas utility's coordination with Pepco and DCSEU to enable the analysis and development of NPAs, including analyzing available electric capacity within the District, electric demand-side management strategies that could avoid the need for distribution system upgrades, and quantifying primary and secondary distribution upgrade costs where applicable.

[27] Beverley Partial Concurrence to Order 22003 at 3.
[28] FC 1179, Hopkins Direct Testimony at 17:16-17.
[29] FC 1179, Botwinick Direct Testimony at 23:9-10, citing Rewiring America, "Report: Upfront cost of home electrification" (Mar. 1, 2024), https://www.rewiringamerica.org/research/home-electrification-cost-estimates.

Near-Term Action Plan

The near-term action plan should provide a detailed, actionable picture of known planned capital and operational expenditures, including NPAs, within six years of the plan filing. The near-term action plan should align with the long-term capital and operational expenditure plans. However, the near-term action plan differs from the long-term plans in that it not only projects overall spending totals but also provides detailed information, enabling the Commission to evaluate and deliver proactive direction on specific planned projects and groups of programmatic projects.

Requirements:

The gas utility must provide the following information on all known discrete planned projects, groups of geographically-related projects, and NPAs during the planning horizon, as applicable:

- Project category
- Scope of work
- Engineering life
- Construction start date
- In-service date
- Cost estimate
- Pipeline length and diameter
- Pipeline material
- Maximum allowable operating pressure
- Impact on revenue requirement and rates
- Project location
- Number of impacted or served customers
- Permitting requirements
- Environmental requirements, and
- Change in projected GHGs due to project
- Geographic Information System (GIS) mapping of the location of the project (see System Mapping section)

The gas utility must present an NPA analysis for all planned pipeline projects in the near-term action plan. The NPA analysis must demonstrate that the NPA is technically infeasible or cost-prohibitive in order for the utility to move forward with the pipeline project in its near-term plan. (See Non-Pipeline Alternative Analysis section.)

Analysis of Depreciation and Stranded Assets

The most effective way to minimize near-term customer costs and mitigate long-term risk is to constrain unnecessary investment in new pipeline infrastructure. Limiting investment into pipeline infrastructure—and thereby limiting the accumulation of rate base—should be the first line of defense against stranded asset risk, as rate base is directly correlated to the total amount that ratepayers must pay for the utility to recover its assets. A depreciation analysis is necessary to evaluate how various proposed investment scenarios translate into rate base, bill impacts, and underutilized or stranded asset exposure over the planning horizon under various depreciation scenarios. This analysis will provide the Commission and stakeholders with a clear understanding of how different depreciation approaches impact rate base recovery and stranded asset exposure under varying scenarios.

Requirements:

- The gas utility must model rate base, rates, and bill impacts and quantify underutilized or stranded assets from the present day through 2050 under the scenarios and sensitivities, under multiple depreciation scenarios.
- Depreciation scenarios must include, but may not be limited to:
    - A straight-line, average life group depreciation scenario
    - An equal life group depreciation scenario
    - A unit of production depreciation scenario
    - A scenario in which all assets are depreciated by 2050.

Comprehensive Leak-Prone Pipe Remediation Plan

The gas utility's accelerated leak-prone pipe (LPP) remediation plan should be subsumed within the long-term gas plan process. The current process, in which WGL's pipe replacement program has been litigated through its own separate docket, has resulted in plans that are disconnected from the market and policy trends, including the District's broader climate strategy. The Commission has acknowledged the misalignment between DC's policies and previous PROJECT*pipes* proposals. In Order 22003 on WGL's PROJECT*pipes* 3 application, the Commission acknowledged "the reality of the need to change the focus of the pipe replacement program to address the District's climate policies, which promote electrification as opposed to use of natural gas."[30] In that Order, the Commission directed the Company to submit a new application reflecting "a focused approach, demonstrating the critical balance between reductions in future leaks and GHG emissions against the risk of stranded assets as the District continues its energy transition."[31]

[30] Order 22003, para. 49.
[31] *Ibid.*

With this directive in mind, the proper venue for evaluation of WGL's LPP remediation plan is the long-term gas plan. Placement within the long-term gas plan will enable the Commission to evaluate whether the LPP remediation plan is "strategically targeted"[32] within the broader context of various possible climate-constrained demand futures. Housing the LPP remediation plan within the long-term gas plan will also enable the Commission to determine whether the gas utility has appropriately minimized the risk of stranded assets.

Requirements:

This straw proposal outlines a comprehensive LPP remediation plan, with the aim of promoting the "focused approach" that the Commission called for in Order 22003. The LPP remediation plan must include the following elements:

- A 20-year plan to remediate LPP at least cost and least risk, using an optimized mix of remediation methods including replacement, repair, and retirement. The 20-year plan should contain a project list, subdivided by year, with the following information for each project:
    - Pipe material
    - Risk score
    - Main diameter
    - Main length
    - Number of customers served by the project
    - The estimated dollar value of each project and 80% confidence interval
    - The year and month the project is anticipated to start construction, for projects planned within five years
    - In-service date, for projects planned within five years
- All information described in Order 22003 at paragraph 51, along with any other information that the PSC determines in FC1154 or FC1179 is needed to evaluate pipe replacement plans.
- A transparent risk ranking of all LPP on the gas utility's system, including methodology, segment-level input data for risk scoring, component scores as applicable, and final scores by pipe segment. Rankings should account for risk factors, including leak history and leak ratios, age, material, and number of customers. The plan must also describe in detail the Company's methodology for risk ranking and project prioritization.
- Prioritization of remediation of pipe (if feasible, NPAs) for environmental justice communities. The plan should present a GIS map that allows the viewer to see the location of LPP layered over the area of environmental justice communities (see the "System Mapping" section next).
- For each LPP segment that the gas utility plans to replace, the utility must demonstrate that neither an NPA nor a combination of repairs and NPAs is feasible and cost-effective. Any cost-effectiveness test must comply with Order 21938 and use the social cost of carbon and methane.

[32] *Id.*, para. 48.

- A description of coordination with the DC municipal government to align municipal projects (e.g., roadwork) and LPP remediation to maximize the feasible deployment of NPAs.
- A description of the Company's use of advanced leak detection to rank risk, prioritize LPP segments for remediation, and generate leak repair activity. This must include a detailed description of the equipment, the survey method, the percentage of the system surveyed in each year, and the survey interval.

System Mapping

System mapping is a critical tool for identifying geographic areas that will face upcoming capacity constraints and for better understanding which areas of the system might be hydraulically feasible to electrify. Detailed mapping can also facilitate geotargeting of electrification and efficiency incentives and facilitate collaboration with municipal officials on neighborhood-scale NPA projects. For example, Pacific Gas and Electric's Gas Asset Analysis Tool provides segment-level mapping of pipeline assets with overlays of electric distribution system data and customer demographic data. A third-party expert consultant recently used this tool to identify and evaluate potential zonal electrification NPA pilots.[33]

Requirements:

This straw proposal recommends that the plan include system mapping requirements, including:

- Use of GIS software to display locations, material, age, pressure, leak history, JANA risk scores, and other characteristics of pipe alongside layers showing planned projects, electrification trends, participation in efficiency and electrification programs, and EJ communities, in line with Commissioner Beverley's recommendations.[34]
- GIS shapefiles may be filed under a highly confidential seal. However, the public version of the Plan should include at least one high-level system map, which may be provided as a PDF.

Line Extension Allowances

Gas line extension allowances (LEAs) are no longer aligned with the District's policy and planning environment. Traditionally, LEAs were justified on the basis that new customer revenues would exceed the incremental costs of service, thereby helping to recover fixed costs shared across the customer base and putting downward pressure on rates.

In light of current market trends and climate policies, system expansion carries heightened risk, particularly in states that have adopted emissions-reduction mandates. Adding new customers under a climate-constrained future increases customer risk: the gas utility incurs additional fixed costs to serve the new customer even as its overall sales and revenues are declining. There is no

[33] Halbrook, Claire. "Selecting Gas Decommissioning Pilot Locations." Gridworks, March 4, 2023. https://gridworks.org/2022/08/selecting-gas-decommissioning-pilot-locations/
[34] Beverley Partial Concurrence to Order 22003 at 6.

reasonable assurance that new customers will remain on the system long enough to recoup the fixed costs required to serve those customers.

Moreover, offering incentives for new customers to join the gas system is directly at odds with the District's broader electrification strategy. Under the current framework, incentives are working at cross purposes—the gas LEA is offsetting electrification incentives that DCSEU provides for new builds. This is an inefficient use of ratepayer and municipal funds, especially given that new commercial and multifamily buildings above three stories must be constructed without gas starting in 2026. Eliminating gas LEAs will streamline incentives in favor of the District's climate policy strategy.

Requirement:

The gas utility shall require all customers seeking an extension for new gas service to pay the entire cost of connecting to the existing distribution system.

Conclusion

The District is at a critical juncture in managing the future of its gas distribution system. Demand for natural gas is declining, while public policy, market, and technology trends are accelerating the transition towards electrification. Forward-looking planning can help mitigate the risk of proceeding with large-scale capital investments that may not align with the District's climate goals or long-term customer needs. This misalignment would expose customers to higher rates, stranded asset risks, and inequitable cost burdens.

The straw proposal presented here outlines a comprehensive approach to gas planning that emphasizes transparency, data-driven analysis, and robust stakeholder involvement. It establishes a regular cadence for long-term plan filings, sets expectations for demand forecasting and capital planning, and requires the evaluation of NPAs and equitable approaches to LPP remediation. These elements are designed to ensure that future gas investments are prudent, cost-effective, and consistent with the District's statutory commitments to reduce emissions.

By adopting a structured gas planning process, the Commission will provide clarity to stakeholders, create accountability for Washington Gas, and minimize customer risk exposure during the energy transition. While this planning framework may not resolve every issue in the gas transition, it establishes a necessary foundation for aligning utility planning with the District's clean energy future.

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Any errors or omissions are the responsibility of the authors.

CERTIFICATE OF SERVICE

I hereby certify that on this 12th day of February, 2026, I caused true and correct copies of the paper titled "Evolving the District of Columbia's Gas Distribution System for a Cost-Effective Clean Energy Transition: A Framework for Long-Term Gas Utility Planning," to be sent by email to the following:

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