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Washington Gas
A WGL Company

1000 Maine Avenue, SW
Suite 700
Washington, DC 20024
www.washingtongas.com

John C. Dodge
Office of General Counsel
(202) 624-6722 (Direct)
Jdodge@washgas.com

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**VIA ELECTRONIC FILING**

Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
1325 "G" Street, N.W., 8th Floor
Washington, D.C. 20005

**Re: FC 1130 – WG Comments**

Dear Ms. Westbrook-Sedgwick:

Pursuant to Order No. 21928 in the above-referenced matter, Washington Gas Light Company hereby files its Comments on the Synapse Value of Distributed Energy Resource Study's procurement activities on the District of Columbia's climate goals.

Kindly direct any questions to the undersigned.

Sincerely,

John C. Dodge
Associate General Counsel and Director,
Regulatory Matters
jdodge@washgas.com
(202) 624-6722

cc: Per Certificate of Service

**BEFORE THE**
**PUBLIC SERVICE COMMISSION**
**OF THE DISTRICT OF COLUMBIA**

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| IN THE MATTER OF<br><br>THE INVESTIGATION INTO MODERNIZING THE ENERGY DELIVERY SYSTEM FOR INCREASED SUSTAINABILITY | ) | Formal Case No. 1130 |

**WASHINGTON GAS LIGHT COMPANY'S COMMENTS**
**<u>ON THE SYNAPSE VALUE OF DISTRIBUTED ENERGY RESOURCE STUDY</u>**

Washington Gas Light Company, ("Washington Gas" or "Company") pursuant to the Public Service Commission of the District of Columbia's ("Commission") Order No. 21928, hereby files its Comments on the Synapse Value of Distributed Energy Resource ("DER") Study ("VDER Study" or "Study"). The Company believes that its underground natural gas infrastructure and related energy solutions, including programs that can and should be considered DER, will play a critical role in delivering value to the District to help reduce greenhouse gas ("GHG") emissions as the District charts a pathway to a decarbonized energy future for its residents and businesses. For this reason, the Company offers constructive input related to issues central to the Study, including compensation mechanisms, and other regulatory approaches to incent access to a broader portfolio of efficient and lower carbon distributed energy solutions, beyond those identified in the Study. This approach supports equitable and affordable energy access and reliability and helps to avoid the expensive and unnecessary overbuilding of electric infrastructure for limited duration peak energy needs. Washington Gas submits the following recommendations to the Commission:

1. **Synapse's Definition of DERs is severely limited:** The Study's analysis and findings use a limited set of DERs that excludes technologies recognized in the working definition used by FERC. The District should align its definition of DERs with FERC.
2. **Equitable Access to DERs**: Renters and residents of older homes in the greater D.C. region face significant barriers to deploying DERs due to limited control over property and energy management, inadequate weatherization, and insufficient supporting electrical infrastructure. The District should account for these dynamics as it works to refine its targets and programs related to DER adoption.
3. **High Upfront Costs of DERs:** The high upfront capital costs associated with DERs, and barriers related to financing and funding can be prohibitive for many consumers. The District should address how these challenges will be overcome to allow for wide-spread adoption of DERs.
4. **Interoperability Challenges:** There are substantial network communications and protocol-related considerations to deploying grid-interactive DERs, such as ensuring cybersecurity and protecting critical infrastructure. The District should ensure that any DER implementation efforts properly account for these inputs.
5. **DER Deployment:** The study does not adequately address the differences between residential and commercial DER deployments, such as the characteristics of and grid impacts resulting from electrifying large commercial load. The District should develop a DER valuation framework should differentiate

between customer use cases.

6. **Incentive Mechanisms:** Key inputs for potential DER incentive mechanisms remain unresolved, including the need for accessible grid constraint information and a clear consensus on what constitutes a DER. The District should ensure consumers have clarity around and access to the appropriate tools and information needed to effectively deploy DERs.
7. **Consumer Choice:** Consumer behavior will have a material impact on the trajectory of the District's DER programs, and there are many practical challenges around consumer choices that will impact how DERs are deployed and whether they are used optimally. The District should appropriately account for the uncertainty created by consumer choice, and its potential harmful impacts on reliability, when creating DER program goals.
8. **Study Assumptions and Results:** Several of the Study's assumptions, findings, and conclusions are unsound and inconsistent with widespread industry consensus. The District should examine these assumptions to ensure it adopts a feasible and safe policy.
9. **Winter-Peaking:** DER grid relief measures modeled in the Study are more effective at addressing summer-peaking scenarios, and the reliability and resiliency of DER solutions during severe winter weather events remains untested and uncertain. The District should explore rates, incentives, and other mechanisms that appropriately value and compensate the system reliability, cost savings, load reduction, and load shifting services that natural gas and thermal solutions can provide during extreme winter weather.

10. **The Value of the Underground Natural Gas Infrastructure and Thermal Energy:** A complimentary and coordinated multi-fuel energy system that includes lower-carbon gaseous fuels, increased reliance on DERs, and an electric system characterized by increasing amounts of renewable electricity has many benefits compared to an all-electric energy system. The District should give consideration to a broad array of DERs, such as CHPs, hybrid heating systems, and thermal energy networks, that can provide important affordability, reliability and effectiveness benefits to the District and its residents.

## I. Overview

Washington Gas respectfully submits these Comments on the VDER Study, prepared by Synapse Energy Economics, Inc. ("Synapse") for the Commission in *Formal Case No. 1130* ("FC1130"). The Company supports the District of Columbia's ("the District" or "D.C.") climate goals while recognizing the priorities of energy affordability, energy security and a safe and reliable energy network. The Synapse Study raises important questions and issues regarding how the District can both reliably and affordably meet its future energy demands. While the Company appreciates the potential benefits that both physical DERs[1] and virtual power plants ("VPP") may bring to the District, Washington Gas agrees with many of the concerns the Study raises related to the costs, practical challenges, timing, and incentive mechanisms needed to spur DER adoption at the levels necessary to provide the breadth of benefits envisioned. The Company shares the concerns expressed in the Study concerning peak demand growth on the District's

[1] For the purposes of these comments and consistency with the Study, DERs include solar photovoltaics, battery storage, energy efficiency, demand response, and managed charging of electric vehicles.

electric distribution grid, the viability of DERs to address so-called “needle” winter peaks, the high costs associated with electrification, including upstream electricity transmission, and generation capacity (and the need to defer or avoid overbuilding to meet such peaks).

Washington Gas disagrees with some of the assumptions used in the Study, particularly in relation to the Study’s assessment of temporal or peak energy usage in their load forecasts, choices of assumptions in construction of the “Main Relief Scenario,” as well as inconsistencies in the Study’s baseline data. In addition, Washington Gas is concerned that the types of DERs considered within the Study are overly limited. While there is not yet a clear consensus within the District, or at large, on what should constitute a DER, the Study’s definition of DERs, which includes only solar photovoltaics, battery storage, energy efficiency, demand response, and managed charging of electric vehicles, is significantly more limited than definitions used elsewhere. For example, the Study notes that the District defines DERs as inclusive of, but not limited to, photovoltaic solar, wind, cogeneration, energy storage, demand response, electric vehicles, microturbines, biomass, waste-to-energy, generating facilities, and energy efficiency. FERC Order 2222 uses a similarly expansive definition, which includes, but is not limited to, electric storage resources, intermittent generation, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment. Finally, the Company is particularly concerned with reliable and secure customer access to energy, especially during peak winter hours, and notes the limitations of certain DERs in these situations, as recognized by the Study, and is further concerned about the potential impacts on and cost to all energy customers.

## II. Background

Washington Gas was founded in 1848 by Congressional Charter and recently marked its 175th year of providing safe, reliable natural gas service to more than 1.2 million residential, commercial, and industrial customers in the District of Columbia (~164k), Virginia (~552k), and Maryland (~513k). Washington Gas operates approximately $5 billion in natural gas system assets across its service territory.

Washington Gas has been a leading voice in offering opportunities and suggestions to meet D.C. climate goals, including through its Climate Business Plan ("CBP") and 5-year and 30-year plans filed in Formal Case No. 1167 ("FC1167").[2] [3] [4] The Company has also been party to the GD-2019-04-M proceeding, which is ongoing and has important implications for how utility investments (including DER) will be valued in the District moving forward.[5] The Study raises issues related to the feasibility, effectiveness, and timeliness of the solutions discussed, the social cost of GHG emissions, the value of reliability and resiliency, and the value of avoided electric capacity (including energy, transmission, and distribution capacity).[6] These issues are important, not only for appropriately valuing DERs, but in valuing utility investments and the District's diverse energy infrastructure. In addition, the Company believes its underground natural gas

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[2] *Formal Case No. 1167, In the Matter of the Implementation of the Climate Business Plan,* (Formal Case No. 1167) Washington Gas. Climate Business Plan (Mar. 2020).

[3] Washington Gas. Climate Change Action Program – Part 1 (Dec. 15, 2021).

[4] Washington Gas. Climate Change Action Roadmap – Part 2 (Jan. 18, 2022).

[5] GD-2019-04-M, In the Matter of the Implementation of the 2019 Clean Energy DC Omnibus Act Compliance Requirements (GD-2019-04-M.)

[6] In the District, energy policies and regulations do not adequately recognize the full lifecycle impacts of GHG emissions beyond the District's own boundary. The Company acknowledges the Commission's recognition of this issue in its Order in GD-2019-04-M and believes that these upstream emissions are particularly important in relation to the electricity the District imports from the surrounding region via the PJM wholesale power market.

infrastructure is already providing many of the benefits examined in the Study in a "distributed" manner, relative to the District's electric infrastructure.

Washington Gas' system is designed to meet its customers' peak energy needs. The Company's infrastructure delivered 27.7 billion cubic feet (bcf) of natural gas to its 164,000 customers in the District on an annual basis in 2022.[7] That same year, the Company's infrastructure delivered over twice the amount of energy delivered by the electric grid into the District on 20 distinct days, and delivered 2.5 times the energy delivered by the electric grid into the District on one of the coldest days of the year, December 23, 2022 (See Figure 1).[8] [9] These figures serve as a useful proxy for understanding the critical role that natural gas and natural gas infrastructure plays in meeting the District's energy needs, particularly during extreme weather events, and the challenges associated with addressing the District's energy demand entirely through the electric grid.

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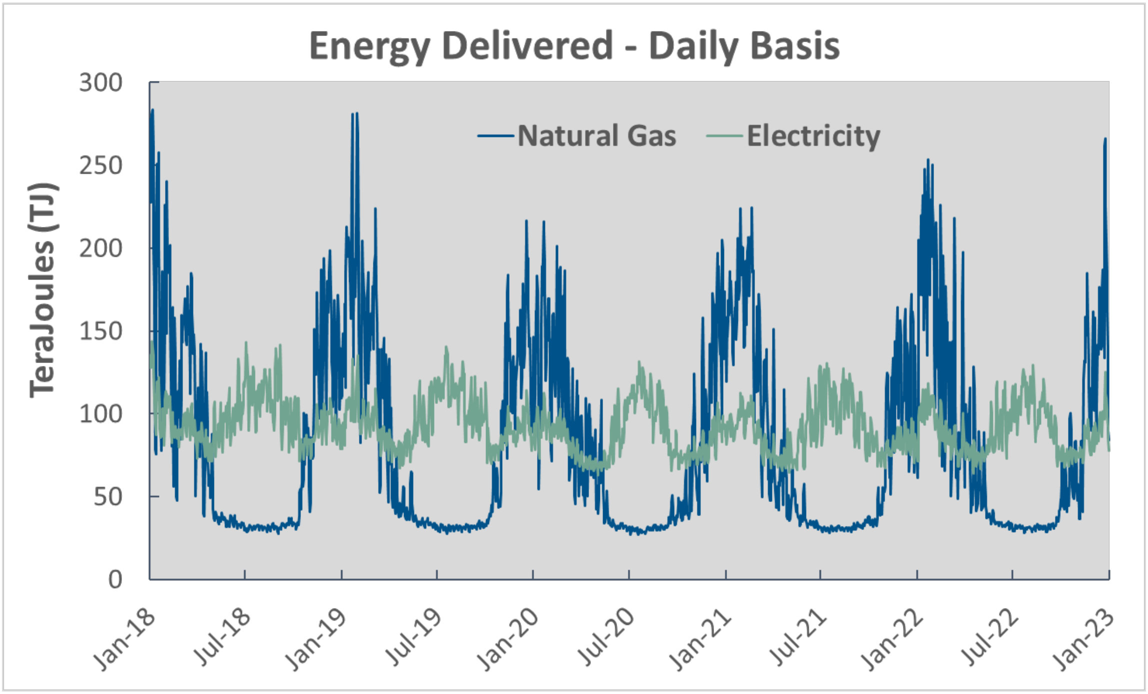
[7] U.S. EIA. Natural Gas Annual Respondent Query System (EIA 176 Data through 2022) (2024).

[8] Based on internal Washington Gas analysis. For natural gas, the Company analyzed daily natural gas system-wide delivery (D.C., Maryland, Virginia) and allocated the D.C. portion according to the portion of historical gas deliveries to D.C. (16%). For electricity, the Company analyzed hourly peak electric deliveries (MW) by PJM to Pepco's system (Maryland and D.C.), assuming that the peak within that hour held for the entire hour and allocated 37% of this to D.C. based on Pepco's annual energy sales split. See Appendix for additional data.

[9] These data, and supplemental analyses and data tables, are available in the Appendix.

*Figure 1 – Comparison of Energy Volumes Delivered to District of Columbia Customers by Washington Gas and Pepco*




The Company maintains over 50 billion cubic feet (bcf) of local and regional energy storage, including aboveground and underground natural gas and propane storage and additional "line pack," which is dispatched to meet the peak energy needs of the District and its surrounding communities. During winter hours, natural gas is essential to ensuring homes, businesses, and other critical infrastructure have the necessary heat and power, keeping residents safe and comfortable and businesses open and operating. The energy resources delivered by today's natural gas infrastructure help District of Columbia customers avoid the significant incremental costs and instability that broad-based policy driven electrification will trigger and that the Study is focused on alleviating. The value of natural gas infrastructure to reliably deliver critical energy during a period of rapidly escalating electricity demand and increasing electrical system fragility must be appropriately recognized. Furthermore, it must be noted that any further moves to curtail rather than leverage natural gas infrastructure will exacerbate both the cost and deliverability of electricity,[10] and could threaten safe and reliable service to the District.

Additionally, the Company's infrastructure provides a stable foundation upon which to advance a lower carbon energy transition while protecting customers from energy instability and cost. It offers the ability to access a portfolio of innovative and ready-now thermal solutions, including combined heat-and-power ("CHP"); dual fuel heating; renewable natural gas ("RNG") or biomethane; and fuel cells. These can reduce GHG emissions and provide reliability and resiliency benefits. Other solutions, such as carbon capture, and the future delivery of zero-emission fuels like hydrogen, are included in many forward-looking lower carbon "pathway" [11] plans, that offer lower-GHG emission energy service at a lower cost to customers than an all-electric approach.

## III. The District Should Use an Equitable and Practical Consumer-Focused Approach to DERs

While the Company supports the investigation of the temporal and spatial value of DERs in the District, and recognizes the potential benefits outlined in the Study, there are

[10] PJM is forecasting 40 gigawatts of retirements on its system between 2022 and 2030, at the same time as it has the longest interconnection queue wait times of any grid operator in the country (consisting of almost 94% renewables, for which the historical rate of successful completion and interconnection has been under 5%), and recently revised its demand forecasts to account for new and unanticipated load growth, including that driven by growing data center demands. These dynamics, taken together, and independent of the fate of the gas delivery infrastructure, are already stressing the regional power grid and consumers who take service from it. *See* PJM. Energy Transition in PJM: Resource Retirements, Replacements & Risks (Feb. 24, 2023); *See* DOE. America's Strategy to Secure the Supply Chain for a Robust Clean Energy Transition (Feb. 24, 2022); See BloombergNEF and The Business Council for Sustainable Energy. Sustainable Energy in America 2023 Factbook (Mar. 2023); *See* JM. Energy Transition in PJM: Resource Retirements, Replacements & Risks (Feb. 24, 2023).

[11] Besides Washington Gas' own Climate Business Plan, filed in 2020 under FC1167 in D.C., Con Edison (Gas Long-Range Plan), Xcel Energy (Clean Heat Plan), and Baltimore Gas & Electric (BGE Integrated Decarbonization Strategy) are among the notable plans from combination gas and electric distribution utilities that also envision a role for hydrogen blending and lower-carbon fuels in the long-term in a least-cost decarbonization pathway.

a range of practical challenges to realizing these benefits that are not included in the Study or require a more fulsome analysis than what is presented. Issues with equitable access, incentive mechanisms, and consumer preferences deserve additional consideration beyond the analysis included in the Study, and the District should account for issues not raised in the Study, such as high upfront costs and interoperability challenges, as it works to promote the adoption of DERs. Each of these considerations pose significant challenges to deploying DERs at the scale and speed necessary to achieve the aggressive benefits envisioned in the Study. The Company presents its view of these challenges here in further detail:

3.1. Equitable Access to DERs: Individuals or households that do not own their homes or living spaces may be limited in their ability to deploy DERs and access certain future incentives or mechanisms envisioned by the Study that would allow customers who install DERs to financially benefit. The age of a home or building can also impact the ability to access DERs. The median age of a housing unit in the greater D.C. region is 69 years old (built in 1955), with nearly a third of housing units at 85 years or older (built in 1939 or earlier).[12] Many older buildings lack the weatherization or building shell necessary to make some of these measures, like demand response ("DR"), optimally effective. For many more, inadequate wiring or electrical panel capacity may limit the ability to install EV charging, electric appliances, or behind-the-meter solar. In each case, building shell and panel upgrades can be more invasive and expensive for older homes,

[12] Point2Homes. Washington, DC Demographics (2024). The survey identified 344,306 housing units in the District, with a median year built of 1955, and 113,235 are built in 1939 or earlier (~32.9%).

if not infeasible altogether. Renters also face challenges in adopting DERs in the manner envisioned. Only 41.4% of housing units in the District are owner-occupied, meaning more than 58% of units are rentals.[13] These residents often do not have the autonomy over their property and energy management required to install DERs. Small businesses or tenants of larger properties may be similarly unable to install or leverage DERs.

3.2. High Upfront Costs of DERs: The Study does not address the upfront capital costs associated with solar PV, EVs (and related charging infrastructure), or battery storage. These are expensive initial investments that most consumers cannot justify without reasonable assurance of the long-term financial benefit. In this way, access to DERs can also be limited by access to low-cost capital and access to subsidized funding, tax credits, rebates, etc. and may primarily affect those that are renters or limited-income individuals (e.g., without sufficient tax liability, tax credit incentives, such as those available under the Inflation Reduction Act, are unavailable). There are also balance-of-plant, controls,[14] and/or telecommunications investments needed to enable full grid interoperability that should be considered.

3.3. Interoperability Challenges: Meaningful network communications and protocol-related barriers exist to deploying grid-interactive DERs in a standard manner that is safe, reliable, and compliant with best-practice cybersecurity standards to

[13] United States Census Bureau. Quick Facts – Washington, D.C. (Jul. 1, 2023).

[14] Balance-of-plant and controls systems are supporting systems that ensure the synchronized operation of power system components. Examples include pumps, fans, heat exchangers, or environmental control systems.

ensure protection of critical national infrastructure.

3.4. Nuances Between Residential and Commercial DER Deployment: The Study also falls short of addressing the nuances between residential and commercial deployments of DER infrastructure, particularly EV charging, where the infrastructure necessary to accommodate aggressive plans to electrify fleets and commercial vehicles will be very expensive (more than $1 trillion nationally, according to recent estimates).[15] These commercial charging facilities are expected to be far less "distributed" than other types of DERs and can place highly local and collective strains on the distribution system. A 2021 study by National Grid and Hitachi Energy on the impact of fleet electrification in National Grid's electric service territory found that, of the 19 distribution feeders studied, 13 could eventually need to be upgraded when nearby fleets fully electrify.[16] Notably, National Grid's analysis *did not* account for other load growth from electrification (at-home charging or the electrification of heat). A single large fleet electrifying, like one (1) of Washington Metropolitan Area Transportation Authority's (WMATA) nine (9) bus fleet garages, could be enough to create a step-change that triggers an expensive, but necessary, upgrade to a substation or feeder.[17] Because the Study used national data and did not factor in the specific fleets within the District, nor their proposed or expected timelines to electrify, it is hard to say how many of the District's 765 feeders could also be

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[15] Clean Freight Coalition. New Report Pegs Cost of Electrifying U.S. Commercial Truck Fleet at $1 Trillion (Mar. 19, 2024).

[16] National Grid and Hitachi Energy. The Road to Transportation Decarbonization: Understanding Grid Impacts of Electric Fleets (Sep. 2021).

[17] WMATA. Zero-Emission Buses (2024).

forced to undertake similar "step-change" upgrades, and whether that impacts the Study's findings.

3.5. Incentive Mechanisms: Several of the key inputs for a potential DER incentive mechanism, as imagined by the Study, remain outstanding. First, the District must consider how it will balance any forecasted need for physical DER (like distributed solar or battery energy storage), both moving forward in time and in different locations on the system, with the traditional useful life of such systems. For instance, it is ineffective to incent DERs in specific locations, hoping that customers adopt a 20-year lifetime device, if the long-term financial support is unknown by the buyer, untenable, or only conditioned for a certain period of time. Second, local grid constraint information is not readily accessible nor published by the local electric utility. This information, along with credible projections of future temporal and spatial grid constraints, would need to be made available more broadly to incentivize the desired consumer adoption and behavior, including "*a new incentive tier for those who can reduce or shift load if they live in areas with potential distribution system pressures*" (p.72). Today, there is no easy and accessible way for a consumer adopting a DER to know if they are in an area with potential distribution system pressures. Similarly, there is a lack of comprehensive and transparent cost data that informs whether deployments of DERs will cause customers to incur expensive building or other infrastructure upgrades that would significantly impact customer willingness to adopt DERs.

Current DER incentive programs in the District (defined to include Energy Efficiency and Demand Response, or "EE/DR") are effective and important for conserving energy, but are not currently deployed in order to address specific temporal or spatial grid constraints.[18] The Study notes that Pepco has asserted that solar, backup generators, and battery storage are not "firm" DER resources, and considers energy efficiency to be a firm resource that it has proposed to support with Requests for Proposals (RFPs) to "reveal" the range of resource costs in the future.[19] As previously noted, while the collective definition of DERs remains in dispute, the Company suggests that networked geothermal, CHP, and other thermal energy network systems, such as natural gas storage, should be seen as "DERs" given their ability to "avoid" or reduce electricity, yet there is no plan in the Study to address their treatment, valuation, and compensation.[20] At the very least, a DER framework or incentive mechanism must be principled and flexible enough to accommodate new technologies or resources that can offer the same range of benefits as those identified in the Study and empower consumers to adopt the technologies that best meet their needs. The Company believes that in order to develop effective policies, rules, or regulations related to future frameworks or mechanisms to monitor, coordinate, and compensate DERs, it is important for the Commission to gather all relevant information and address information gaps.

3.6. Social Cost of Greenhouse Gases: The Study notes that reduced GHG

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[18] *"As proposed, none of the DCSEU or Pepco efficiency programs target peak hours or geographic locations that are likely to become constrained."* (p.16).

[19] Footnote 24: "*Pepco asserts that energy efficiency is considered a firm DER resource. Pepco also asserts that backup generators and solar are not firm DER resources. Battery storage, when dispatched to meet generation and transmission peaks, is also not a firm DER resource. Electric vehicles are not discussed in the ACR*." (p. 63).

[20] It is well-understood that networked geothermal and thermal energy network systems for residential and commercial heating can avoid straining the electric grid, especially during peak heating and cooling hours.

emissions, valued by the assignment of a "societal cost" of carbon or GHG emissions on a per ton basis, is a key benefit (value) of deploying DERs. However, there is considerable variation and inconsistency in how GHG emissions are valued, with potentially significant implications for the ultimate value of DERs. Throughout 2022, Regional Greenhouse Gas Initiative ("RGGI") prices for CO2 emission allowances on their secondary market ranged from ~$13.00-$14.00 per short ton, or roughly ~$14.00-$15.50 per metric ton CO2e.[21] This is less than one eighth of the median value used by the Study ($128 per short ton CO2e, or ~$138 per metric ton CO2e) and less than the draft value proposed by the Environmental Protection Agency ("EPA") in 2023 ($230 per metric ton CO2e).[22] The study gives great weight to the "social costs" in valuing DER investments and its uncertainty and variability is not conducive to developing reliable incentive mechanisms. Additionally, a move towards hourly GHG accounting in the electricity markets, including in PJM,[23] further complicates DER operation and accounting. For instance, charging, discharging, or refraining from charging a battery or an electric vehicle at different hours of the day, week, and year can result in a different net GHG emissions impact. The District should think carefully about how to appropriately measure, value, and compensate GHG emissions reductions from DER adoption and adopt a consistent and principled

[21] RGGI, Inc. Annual Report on The Market For RGGI CO2 Allowances: 2022 (Apr. 2023). RGGI is a cooperative effort between a number of Eastern states (including Maryland) to reduce emissions of carbon dioxide from the power sector.

[22] These values are reflective of a 2% discount rate. The Study notes the impact of the discount rate on the value of avoided GHG emissions. "*The selection of an avoided GHG value and discount rate are important decisions as they shape the benefits that can be achieved by DERs and their cost-effectiveness.*" (p. 8).

[23] PJM Inside Lines. PJM EIS To Produce Energy Certificates Hourly (Feb. 13, 2023).

approach that does not favor one technology over another.

3.7. Consumer Choice: Consumers that adopt DERs have choices related to the type, size, and usage of the resource. Consumer behavior is challenging to control, incentivize, limit, and ultimately predict such that DERs do not provide the same reliability benefits because they may not be used in an optimal manner. Similarly, some customers may not wish to adopt DERs or opt-in to EE/DR services, irrespective of promised benefits or available incentives. The Company cautions the District against "betting the grid" – risking safe and reliable service – on its ability to achieve these collective outcomes related to spatial and temporal DER penetration, adoption, and usage. As a part of the Maryland Public Service Commission's recent Electrification Study, the Brattle Group, who administered the study, significantly tempered their assumptions related to DER adoption, smart thermostat and time-of-use rate enrollment, and wholly-dropped their modeling of vehicle-to-grid (V2G) benefits after stakeholders and electric utilities pushed back on the feasibility of achieving such high levels of consumer adoption and opt-in on relatively short timelines.[24] Pepco Holdings' Delmarva Power-PJM-Sunverge VPP pilot is facing similar challenges with customer behavior for a utility rebate program in which customers were provided behind-the-meter battery systems: "*Delmarva 'gave batteries to customers at no charge in return for allowing utility control when demand drives prices high, but customers wanted the batteries for their own backup power.'*"[25] The District should remain skeptical

[24] The Brattle Group. An Assessment of Electrification Impacts on the Maryland Electric Grid (Jan. 2024). Pages 82-83.
[25] Utility Dive. Tackling 3 key issues can help scale virtual power plants and spur a wave of benefits, analysts say | Utility Dive (Apr. 17, 2024).

of its ability to realize any "ambitious" or "maximum" outcomes, due to realistic constraints on consumer behavior, including the modeled "technical" potential of achieving 30% peak load reductions during the top 266 hours of the year put forth by the Study authors.[26]

## IV. There Are Critical Issues with the Study's Assumptions and Results

While the Company appreciates the depth and breadth of the Study, and supports many of the Study's sentiments, it has significant issues with several assumptions, and therefore, some of the Study's findings and conclusions.

First, the "Main Relief Scenario," relies on incorrect assumptions, particularly as it relates to the modeling of building electrification. The Study authors found that "*peak load nearly doubles with the building and vehicle electrification pressures, but the combination of load-shaping relief measures brings the load back to near current levels.*" (p.35). Washington Gas questions the finding that the "doubling" peak load impact of building electrification could be almost entirely mitigated through a high adoption of building retrofits. This may be attributable to Synapse's choice to model an aggressive case from NREL which assumes a high degree of building shell improvements or retrofits.[27] The assumption of a high degree of building shell improvements or retrofits leads the Study's authors to find that the average energy consumption of a home or building is much lower than what the peak load reduction would be. This does not align with other study findings

[26] "*The main load flexibility scenario elected was for reductions of 30 percent of peak load during the top 266 hours (the number of hours in which wholesale capacity prices are concentrated) and targeting of the highest cost hours after load shaping Main Relief was applied. While 30 percent reductions of peak load for that many hours may be ambitious, the technologies to accomplish this level of curtailment are diverse and rapidly advancing. With proper incentivization in the coming years, the Study Team believes 30 percent is an attainable technical potential*," (p. 39).

[27] NREL's EUSS Measure Package 10 assumes 1) whole-home electrification, 2) high efficiency appliances, and 3) an enhanced enclosure package.

relating to retrofit cost or customer adoption. High upfront costs are a significant barrier to such improvements and older buildings are typically more complex and expensive to improve. The Rocky Mountain Institute ("RMI") estimated deep building retrofit costs to range from $25-$150 per square foot for commercial buildings.[28] The significant renovations and operational changes needed to fully electrify a building—from opening walls and modifying HVAC and air handling systems, to making building shell improvements, and temporarily shutting down critical building services—can be highly disruptive to tenants and businesses and may only be made easily (but still not cheaply) during vacancies or during turnover between tenants. Intensive renovations may also require building owners to pay for tenant relocation during renovation. In New York City, where the nation's first building performance standard is in place, firms are estimating that retrofits can take as long as 10-12 years for large commercial buildings.[29] The Company believes that overestimating the adoption of building shell improvements or deep energy retrofits result in underestimating the peak load impacts of heating, which may lead the Study to discount the timing and number of District feeders that may become winter peaking. The prospect of a winter-peaking system is likely to create significant challenges for maintaining the safety, reliability, and resiliency of the District's energy systems, such as the ability accurately forecast load and ensure that sufficient fuel supplies and generators remain available during long-duration cold weather events.[30]

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[28] Rocky Mountain Institute (RMI). Guide to Building the Case for Deep Energy Retrofits (Sep. 2012).
[29] UtilityDive. Heat pumps are hot, but commercial retrofits face cold realities (Nov. 1, 2023).
[30] North American Electric Reliability Corporation. 2023 – 2024 Winter Reliability Assessment (Nov. 2023).

Additionally, building electrification pressure is incorrectly modeled as a percent increase based on the current hourly loads.[31] The Company notes that incremental load from the electrification of heat (where gas heating is replaced with electric) is unlikely to mirror current hourly energy loads. Using average current energy loads is likely to significantly underestimate the true peak load impacts of the electrification of heating on many circuits for the peak winter hours. Second, the Study drastically underestimates the degree to which the electric system (including the Bulk Power System) will transition to winter-peaking. To forecast load on the regional transmission and Bulk Power System in PJM, the Study authors used the NREL EULP and EUSS scenarios.[32] These scenarios, however, *are not* constructed as Design-Day hourly peak scenarios, rather they show monthly average hourly peaks. While the PJM PEPCO zone is still summer-peaking on balance today, PJM as a whole is anticipated to convert to winter-peaking under high degrees of electrification.

The Study authors presumed the wholesale market would remain summer-peaking (July and August weekdays, 2-7 PM) through 2045[33] in their analyses, and the associated transmission capacity costs over the same period would remain constant (p.101). The Company notes that this assumption is not consistent with other studies. In 2021, Pepco and the Brattle Group projected that the District will become winter-peaking

[31] "*Building electrification pressure is modeled as a percent increase based on the current hourly loads,*" (p. 30).
[32] "*This study referenced the National Renewable Energy Lab (NREL) studies on End Use Load Profiles (EULP) and End Use Savings Scenarios (EUSS). These studies were designed to support electrification planning, decarbonization analysis, utility integrated resource plans, and policy and rate design*." (p. 182).
[33] *"This kind of demand response measure represents a short-to-medium-term and market-oriented load responsiveness that would lead to avoidance of charging during the hours when the wholesale market is likely to peak (July and August weekdays, 2-7 pm in this study)*." (p. 85).

under widespread electrification.[34] A DC DOEE 2023 Study noted that, with combined electrification loads, the time of greatest stress on substations is 7:00 AM on winter mornings, not summer evenings.[35] The NREL EULP and EUSS scenarios used by the Study also show a locally winter-peaking system in the District, with annual residential electricity usage peaking in 2018 on February 4th.[36] PJM expects its winter peak to climb from 135 GW last winter to 165 GW in the 2033/2034 winter, and expects its average annual winter peak (2% per year) to exceed that of its summer peak (1.7%).[37] In Maryland, the Brattle Group's Electrification Study, which is based on a high building electrification scenario, found that Maryland's grid (on balance) switches to become predominantly winter peaking as soon as 2026-2027.[38]

## V. Winter Peaking Issues: Key Implications

The Study notes that because large distribution capacity projects are relatively expensive, and because they are driven by the peak hour of load, "needle" peaks that cause feeders to exceed their normal rating during only a few overloaded hours are among the most expensive events for customers (in terms of $/MWh).[39] Washington Gas

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[34] Pepco and The Brattle Group. FC1167: An Assessment of Electrification Impacts on the Pepco DC System (Aug. 27, 2021). "*Heating electrification eventually will shift the Pepco DC system peak to the winter season. Currently, Pepco DC's winter peak demand is lower than its summer peak demand,*" (p. 22).

[35] The District of Columbia Department of Energy and Environment Energy Administration. Formal Case No. 1130 and Formal Case No. 1167: The Strategic Electrification Roadmap for Buildings and Transportation in the District of Columbia (Apr. 5, 2023).

[36] National Renewable Energy Laboratory (NREL). EUSS ResStock National 2018 Release 2022.1 – District of Columbia – Timeseries Data (2022).

[37] Utility Dive. PJM triples annual load growth forecast to 2.4% driven by data centers, electrification (Jan. 2024).

[38] Maryland Public Service Commission. Electrification Study Results – Presentation to Economic Matters Committee and Environment and Transportation Committee (Jan. 16, 2024).

[39] "*Because large distribution capacity projects are relatively expensive, and because they are driven by the peak hour of load, "needle" peaks that cause the feeder to exceed its normal rating during only a few overloaded hours are among the most expensive events in terms of $/MWh. These peaks have the potential to drive hundreds of millions of dollars of capacity investment across the District when a few hours of relief could defer or avoid the upgrade.*" (p. 8).

concurs with this finding and agrees that the District should prioritize identifying such winter-peaking feeders as soon as possible and put careful thought into the value of relief measures.[40] The winter peaks will significantly worsen and require higher levels of investment if policies force a shift away from the use of the natural gas distribution infrastructure, especially during instances of extreme or prolonged cold temperatures. The natural gas infrastructure delivers a sizable portion of total energy demand on a given winter heating degree day, and a very significant portion on the coldest days/hours of the year. A study by NW Natural, looking at the coldest hour on their system in 2022 (December 22, between 8 and 9 am) estimated that over 3.4 GW of new electric capacity would be required to provide the same energy via the electric distribution system that the utility's natural gas distribution system served, at an incremental cost of $4 billion to serve that winter peak.[41] Critically, NW Natural's analysis only considered *energy* costs and did not include the incremental transmission or distribution system costs (which the Study estimated could *exceed* energy costs in their potential avoided value).[42]

More recently, during the week of January 13-19, 2024, which saw extreme cold and winter storms across much of the country, natural gas made up 62% of all of the energy delivered across the United States economy, as compared to less than 2% of energy from solar power.[43] This inability for solar power (the primary non-emitting and

[40] "*It will likely be important for the District to put careful thought into relief measures for winter-peaking feeders because more feeders may become winter-peaking over time with increased electrification. The modeled relief in this study (building retrofits, EVs, and solar generation) was more adept at addressing potential pressures on summer-peaking feeders than on winter-peaking feeders*," (p. 7).
[41] NW Natural. Understanding Peak Demand (2023).
[42] The Study also noted the uncertainty around potential distribution upgrade costs: "*Distribution upgrade costs are both less well studied and vary significantly based on the local grid configurations, including certain equipment (e.g., transformer) size and location and load profiles.*" (p. 7).
[43] American Gas Association (AGA). Natural Gas Has Become the Indispensable Energy Source (Feb. 6, 2024).

energy-generating DER identified in the Study) to reliably generate electricity has been credibly analyzed elsewhere in the United States. The Midcontinent Independent System Operator ("MISO") found that the accredited capacity on its system was anticipated to *decrease* in the medium-term, despite the overall increases in capacity installed.[44] This is due to the lower capacity accreditation of solar and wind, at approximately 20% and 16.6% accreditation, respectively, in the long-term, relative to 95% accreditation or more for traditional thermal resources. This was anticipated to lead to potential load interruptions of 3-4 hours in length for 13-26 days per year when solar and wind were reduced or unavailable.[45] Today, the District receives about 98% of its electricity from power plants in surrounding states. During peak winter hours, renewable energy made up <1% of all energy delivered and solar made up <0.5% of all energy delivered within PJM.[46] It is unlikely that the intense and inflexible energy demands of such winter peaks can be satisfied via electricity in the future without significant upgrades to both the regional transmission system and local distribution system circuits. The Study notes that more feeders may become winter-peaking than anticipated and that the DER relief modeled in the Study "*was more adept at addressing potential pressures on summer-peaking feeders than on winter-peaking feeders*," (p.8). The one winter-peaking feeder modeled in the Study, "Feeder 3," "*continues to experience pressure as the relief scenario is not well designed for a feeder that is winter-peaking,*" and the Feeder's "*winter [peak load] has*

[44] *"MISO modeling indicates that a reduction of that magnitude could result in load interruptions of three to four hours in length for 13-26 days per year when energy output from wind and solar resources is reduced or unavailable. Such interruptions would most likely occur after sunset on hot summer days with low wind output and on cold winter days before sunrise and after sunset."*

[45] Midcontinent Independent System Operator (MISO). MISO's Response to The Reliability Imperative (Feb. 2024). Accredited capacity reflects how much energy resources are realistically expected to produce during times when they are needed the most by accounting for their performance, which includes limiting factors such as their forced outage rates during adverse weather conditions.

[46] PJM. Winter Storm Elliot Report - Event Analysis and Recommendation Report (July 27, 2024).

*greater value, 1.6x that of summer,*" (p. 50, 57). The Study additionally asserts that increasing electrification will affect feeders for "*only a few hours per year at first.*"[47] The Company's analysis of NREL EUSS data analysis found that over 200 hours in the year experience significantly increased peak loads (more than 1.8 times the baseline scenario peak loads) as electrification pressure builds (also not considering "Relief" measures).[48]

The Study also proposes further exploration of rates, incentive tiers, or other mechanisms that would reward customers or system participants that can reduce or shift *electric* loads on overloaded feeders or areas of the system during such peak events, which provides an opportunity for gas and thermal solutions that can achieve these outcomes, wholly or partially. The Study failed to consider the role of gas and thermal solutions. The Company recommends the District also consider new, innovative approaches to valuing and compensating any energy infrastructure that ensures the greatest reliability outcomes at the lowest total cost to the consumer. There is already precedent for such structures and incentives. In Canada, the government of the province of Québec encouraged the development of a joint GHG reduction program by Hydro-Québec and Énergir, the largest electric and gas utilities in the province, which created a program to share costs across their customer bases. The approved "dual energy" program recognizes the benefits of the natural gas infrastructure in reducing peak electric loads and providing reliable energy. Canadian regulators approved compensatory payments from Hydro-Québec to Énergir to compensate for gas demand lost to incremental electrification, distributing ratepayer savings more equitably across natural

[47] Synapse, 8. Table ES- 1. Summary of Key Findings (#3).
[48] National Renewable Energy Laboratory (NREL). EUSS ResStock National 2018 Release 2022.1 – District of Columbia – Timeseries Data (2022).

gas and electricity customers.[49] The program was premised on the notion that an all-electric system would increase the system winter peak by between two (2) and four (4) times and could cost roughly $2.4B more to ratepayers to meet heating demand via electric technologies, primarily due to the high demands during system winter peak events. Washington Gas already has a natural gas DR program in place in Maryland through its EmPOWER energy efficiency programs, which could similarly provide support in the District while also lowering costs for customers. Programs like this represent a win-win for all impacted entities.

The operation of different types of energy infrastructure under such severe winter weather events, like Texas' Winter Storm Uri (2021) or the Mid-Atlantic's Winter Storm Elliott (2022), can be unpredictable. The Study recognizes that the reliability and resiliency of its DER solutions remains largely untested and uncertain, with potential "endogenous risks" arising from distributed systems related to coincident behavior.[50] Washington Gas supports efforts to bolster the reliability and resiliency of the District's energy supply and infrastructure. As such, The Commission must ensure that DERs will help and not hurt the grid during the periods of greatest stress in order to be dependable to protect human life and ensure public safety during such events.

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[49] S&P Global. Quebec's hybrid gas-electric approach to decarbonizing building space heat (Jun. 23, 2022).

[50] "*Energy distribution systems are facing greater risks from what once were considered "once-in-a-hundred year" events….it is more necessary than ever to ask "what if" questions in regard to systems designs, asking whether the system will be able to function when these kinds of events occur...there are some endogenous risks arising from the emerging distributed systems themselves...specifically, as loads become more flexible, designs will need to consider the impact of coincident demand on various circuits*." (p.87).

## VI. The Value of Underground Natural Gas Infrastructure and Thermal Energy

Washington Gas believes that its infrastructure is a critical component of today's and tomorrow's integrated energy system. A complementary and coordinated multi-fuel energy system presents a cost-effective, secure, reliable, resilient, and feasible path forward. This can include roles for lower-carbon gaseous fuels and support for increased reliance on DERs, as well as an electric system powered by higher levels of intermittent renewable electricity generation. The Company appreciates the Study's inherent focus on preserving affordability[51] and on the benefits to affordability by avoiding such large investments that can be mitigated through other strategies, including DERs. The Commission can also achieve this objective by continuing to leverage the underground natural gas infrastructure and other thermal solutions, such as those put forth by Washington Gas in its 2020 Climate Business Plan ("CBP").[52] The Company's CBP compared different decarbonization pathways and highlighted the cost savings that a fuel neutral approach (including gas infrastructure) offered versus a higher cost policy-driven electrification pathway.

Direct use of natural gas by residential customers often has less GHG emissions at a lower cost than electricity. While outcomes are dependent upon appliance efficiency and other factors, they are also heavily determined by the fuel source and energy losses in electricity production, transmission, and distribution.[53] For commercial and industrial ("C&I") customers, CHP systems offer many of the same benefits as DERs, while avoiding

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[51] "*When the need for large investments can be deferred or avoided, the ratepayer benefits can be substantial,*" (p.8).
[52] Washington Gas. Climate Business Plan (Mar. 2020).
[53] AltaGas. Fundamentally Focused - 2023 Investor Day (Dec. 5, 2023). Page 56.

grid costs. Currently, many CHP installations have the ability to be grid-balancing or grid-interactive with a microgrid configuration. CHP systems can also leverage blends of RNG or other lower-carbon fuels, emerging carbon capture solutions, etc. to reduce GHG emissions even further, on top of already-high efficiencies as compared to central plant power and transmission and distribution delivery. In 2020, the Company, as part of its Climate Business Plan, also proposed hybrid heating as a solution for avoiding the costs and reliability issues associated with winter peak electricity usage, an approach that is now being pursued in other jurisdictions.[54] In Maryland, the Building Codes Administration released a recent report that stressed the benefits of strategies to replace carbon-based systems with hybrid or mixed-fuel systems where conditions don't allow for full-electric replacement, due to retrofit challenges or prohibitive up-front costs, such as in large residential or commercial buildings.[55] In the future, hybrid heating systems can leverage blends of lower-carbon fuels to provide low or no GHG emissions. The Company is interconnecting RNG projects to its system, which can provide customers with an additional source of resilient, local supply that also avoids significant GHG emissions. Washington Gas is also actively exploring use cases for thermal energy networks such as geothermal, as well as other waste thermal sources such as sewer gases. These systems can offer higher efficiencies and lower emissions, while reducing peak electric delivery needs in both the summer (for cooling) and in the winter (for heating), helping to avoid costly upgrades associated with meeting peak demand in either season. The high value of avoided electricity costs that result from geothermal and thermal energy networks

[54] Other leading utilities have recognized and are investigating the benefits of hybrid heating, including BG&E, CenterPoint Energy (MN), and Énergir (BC).
[55] Maryland Building Codes Administration (Department of Labor) - Report to the Public Service Commission and Legislative Policy Committee (February 1, 2024).

has been widely recognized in recent policies and regulatory proceedings, including in Massachusetts, New York, Minnesota, and Maryland, as well as by the United States Department of Energy. The Company recommends that the District consider these benefits, the same benefits as those in the DER Study, as it progresses towards a framework or mechanism that seeks to incent a wide range of DER technologies, and not limit its thinking to only the DERs identified in the Study. Appropriately ascribing value to the benefits provided by thermal energy systems and resources, in terms of the reliability and affordability benefits to customers, and the relief they can provide for the electric system, as well as other "distributed" benefits they can provide to local energy consumers (including avoided GHG emissions), will be critical to ensuring the District enables the market to reward those technologies and solutions that are the best fit for consumers and produce the greatest benefits for the District's energy system.

## VII. Conclusion

The Company recognizes and appreciates the charge of the Study authors in developing the *Value of DER* Study and commends the Study for its investigation of an important issue. Washington Gas would like the Commission and other stakeholders to seriously consider the many challenges that the District faces, raised by the Study, related to high generation, transmission, and distribution capacity costs, the corresponding impacts to ratepayers, and the potential for significant negative impacts on reliability and resiliency, especially as the system moves towards winter-peaking. Washington Gas shares many concerns outlined in the Study and supports the further investigation necessary to realistically evaluate the costs and benefits of DERs, as well as the frameworks or structures to appropriately incentivize and fund utility infrastructure in the

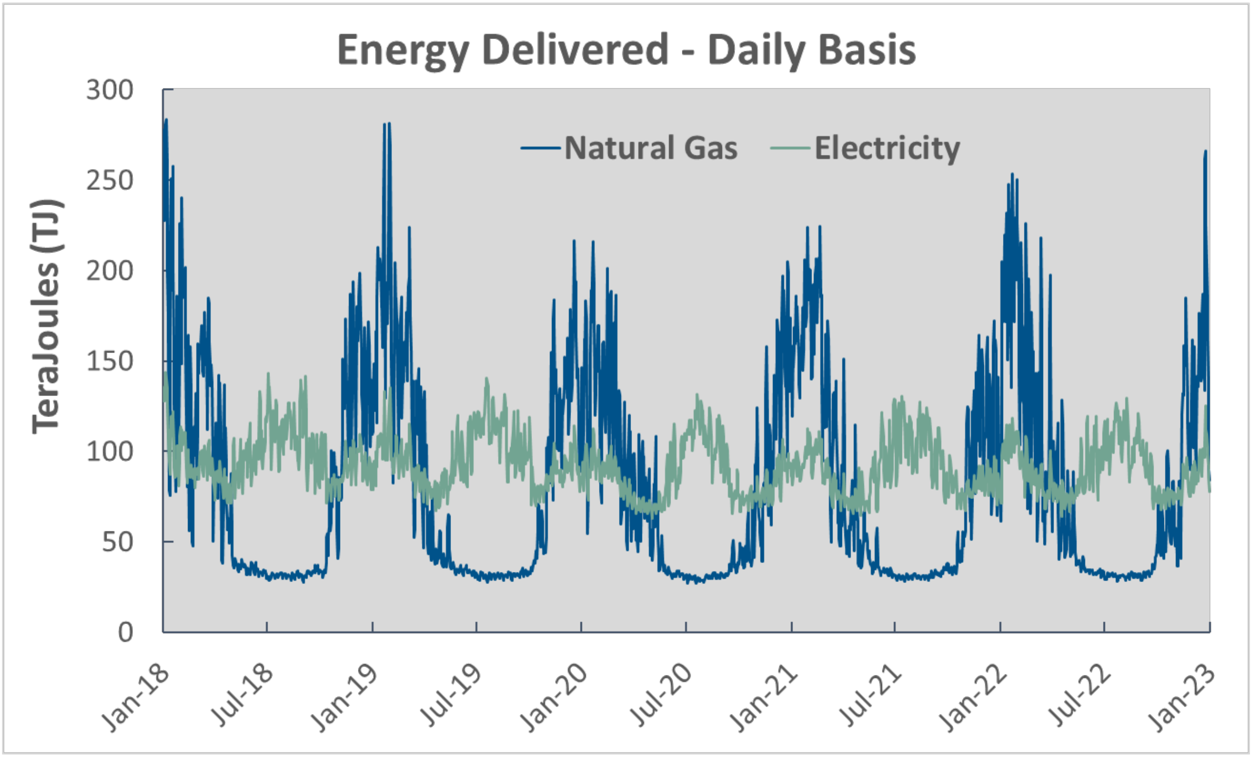
District, including DERs. As the Commission continues to investigate several matters of consequence in open formal cases (e.g., FC1167, GD-2019-04-M, etc.) – such as avoided costs, compensation mechanisms, and reliability and resiliency – the Company believes that the many benefits of the underground natural gas infrastructure and other thermal energy solutions that help alleviate some of the concerns raised in this report should receive fair treatment under any potential framework or compensation mechanisms that may be developed.

Respectfully Submitted,

John C. Dodge
Associate General Counsel and
Director, Regulatory Matters
jdodge@washgas.com
(202)624-6722

**APPENDIX**

**Comparison of Energy Volumes Delivered to District of Columbia Customers by Washington Gas and Pepco**




Natural gas is critical to meeting the current and future energy needs of the District of Columbia.

On December 24, 2022, the coldest day of the year with temperatures dropping to 9°F, Washington Gas delivered over 266 Terajoules (TJs) to District of Columbia customers, more than twice the amount – 130 TJs – that Pepco delivered on its peak summer day. On 27 different days in 2022, the Company delivered more than 150% of the energy that Pepco delivered during its other highest energy delivery days.

To assess the volumes of energy delivered by the respective energy providers, Washington Gas analyzed daily natural gas system-wide delivery (D.C., Maryland, and Virginia) and allocated an amount to the District of Columbia according to the proportion of historical gas deliveries to the District (16%).

To determine  electricity delivered to the District of Columbia, the Company used data published by the PJM Interconnection (PJM) – the regional transmission organization (RTO) that coordinates the movement of wholesale electricity in the mid-Atlantic region serving Pepco – that reported the peak electric power deliveries (in MWs) onto Pepco's system (Maryland and D.C.)[56] and assumed the PJM's peak power measure within a given hour was constant for the entire hour (to obtain MWhs). These volumes were then allocated to the District of Columbia based on the proportional amount of Pepco's annual energy system sales to District of Columbia customers, 37%[57] as reported in EIA data.

The Company converted both MMBTUs and MWhs to a common energy unit, Joules, for ease of comparison.

[56] From PJM.com

[57] From EIA. Electric Sales, Revenue, and Average Price with Data for 2022: Class of ownership, number of consumers, sales, revenue, and average price by State and utility: T10 - All Sectors https://www.eia.gov/electricity/sales_revenue_price/index.php

Comparison of Electric and Natural Gas
Energy delivered into D.C.
For the first half of 2022
Amounts in Terajoules (TJs)

| | Jan | | Feb | | Mar | | Apr | | May | | Jun | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Pepco | WGL | Pepco | WGL | Pepco | WGL | Pepco | WGL | Pepco | WGL | Pepco | WGL |
| **1** | 71.3 | 61.4 | 105.0 | 183.0 | 89.0 | 118.7 | 78.8 | 105.8 | 68.2 | 56.1 | 119.4 | 34.1 |
| **2** | 71.3 | 101.7 | 98.7 | 140.6 | 81.3 | 88.4 | 72.6 | 85.5 | 76.0 | 41.9 | 109.5 | 34.3 |
| **3** | 98.4 | 205.0 | 90.5 | 103.5 | 81.9 | 141.1 | 72.4 | 105.8 | 76.8 | 44.5 | 90.3 | 34.2 |
| **4** | 104.2 | 191.5 | 90.3 | 170.4 | 90.3 | 143.1 | 82.4 | 91.8 | 79.8 | 42.7 | 82.7 | 32.5 |
| **5** | 101.6 | 171.4 | 97.8 | 215.5 | 77.4 | 81.1 | 81.6 | 85.7 | 76.1 | 43.9 | 78.6 | 34.3 |
| **6** | 96.0 | 172.0 | 99.1 | 189.8 | 72.5 | 50.0 | 78.9 | 74.2 | 77.4 | 57.1 | 86.7 | 34.2 |
| **7** | 106.2 | 219.7 | 99.9 | 170.0 | 76.7 | 65.6 | 81.2 | 99.7 | 72.7 | 88.6 | 91.9 | 34.1 |
| **8** | 102.9 | 196.7 | 95.7 | 167.8 | 77.2 | 105.9 | 76.8 | 79.4 | 71.5 | 88.7 | 102.4 | 33.8 |
| **9** | 95.1 | 171.7 | 92.1 | 127.7 | 86.9 | 143.9 | 72.0 | 98.7 | 75.0 | 59.9 | 96.5 | 34.6 |
| **10** | 104.6 | 209.9 | 85.7 | 126.1 | 85.5 | 123.3 | 74.6 | 115.6 | 74.0 | 49.5 | 87.9 | 33.1 |
| **11** | 114.5 | 231.7 | 83.7 | 84.2 | 79.8 | 93.4 | 77.5 | 65.7 | 75.1 | 43.7 | 77.7 | 32.0 |
| **12** | 104.6 | 170.5 | 74.3 | 112.2 | 92.4 | 218.4 | 75.4 | 46.4 | 78.4 | 40.3 | 85.0 | 32.9 |
| **13** | 95.4 | 150.8 | 91.6 | 198.1 | 93.0 | 173.7 | 79.1 | 40.3 | 81.1 | 37.2 | 114.4 | 32.2 |
| **14** | 93.5 | 176.7 | 108.5 | 226.1 | 85.7 | 104.2 | 81.1 | 48.2 | 75.6 | 37.6 | 107.7 | 33.1 |
| **15** | 107.0 | 247.8 | 106.2 | 190.1 | 78.2 | 74.3 | 70.8 | 45.1 | 77.8 | 37.4 | 111.0 | 32.9 |
| **16** | 114.6 | 213.3 | 94.7 | 120.6 | 75.6 | 61.2 | 67.2 | 45.7 | 84.5 | 39.2 | 110.0 | 33.0 |
| **17** | 102.5 | 199.6 | 84.0 | 68.4 | 77.8 | 77.8 | 64.0 | 78.6 | 80.9 | 39.5 | 119.4 | 31.6 |
| **18** | 105.2 | 193.5 | 83.3 | 163.1 | 75.1 | 48.5 | 83.8 | 128.2 | 77.1 | 38.8 | 82.9 | 32.3 |
| **19** | 96.5 | 135.1 | 91.5 | 195.5 | 68.3 | 49.5 | 82.3 | 115.8 | 85.1 | 37.8 | 73.0 | 33.2 |
| **20** | 99.3 | 215.2 | 92.3 | 166.8 | 68.3 | 88.6 | 77.4 | 76.7 | 101.2 | 34.4 | 81.3 | 33.7 |
| **21** | 118.5 | 253.7 | 83.9 | 95.8 | 74.7 | 68.4 | 75.8 | 59.4 | 107.5 | 33.4 | 92.2 | 32.7 |
| **22** | 109.0 | 220.3 | 82.2 | 65.8 | 73.9 | 66.9 | 73.7 | 46.9 | 100.2 | 35.4 | 101.1 | 32.8 |
| **23** | 100.3 | 183.7 | 77.3 | 95.8 | 78.4 | 88.1 | 68.2 | 41.4 | 84.8 | 37.7 | 88.4 | 35.1 |
| **24** | 100.1 | 171.9 | 95.5 | 176.8 | 77.9 | 85.3 | 70.6 | 43.2 | 77.8 | 41.9 | 93.0 | 33.3 |
| **25** | 99.3 | 193.2 | 93.2 | 150.8 | 75.2 | 79.0 | 75.2 | 46.0 | 76.8 | 40.0 | 97.7 | 30.0 |
| **26** | 109.1 | 229.3 | 87.6 | 155.2 | 74.3 | 122.6 | 76.5 | 55.2 | 81.0 | 37.0 | 100.9 | 30.6 |
| **27** | 111.1 | 196.2 | 81.9 | 128.4 | 85.0 | 168.7 | 73.6 | 88.3 | 86.2 | 34.7 | 102.6 | 33.8 |
| **28** | 104.0 | 195.0 | 87.8 | 143.3 | 100.3 | 197.7 | 76.3 | 89.2 | 77.1 | 35.3 | 90.0 | 34.0 |
| **29** | 111.2 | 250.6 | | | 96.9 | 158.1 | 73.5 | 72.3 | 80.1 | 33.6 | 100.0 | 33.6 |
| **30** | 111.1 | 225.4 | | | 87.3 | 87.2 | 66.5 | 53.5 | 96.7 | 34.2 | 110.5 | 32.3 |
| **31** | 110.7 | 211.7 | | | 79.4 | 55.4 | | | 115.9 | 33.9 | | |

Comparison of Electric and Natural Gas
Energy delivered into D.C.
For the second half of 2022
Amounts in Terajoules (TJs)

| | Jul | | Aug | | Sep | | Oct | | Nov | | Dec | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Pepco | WGL | Pepco | WGL | Pepco | WGL | Pepco | WGL | Pepco | WGL | Pepco | WGL |
| **1** | 116.6 | 30.0 | 108.2 | 31.6 | 100.2 | 31.9 | 71.8 | 43.8 | 76.2 | 47.5 | 91.6 | 161.6 |
| **2** | 109.0 | 29.1 | 116.2 | 31.6 | 100.4 | 30.2 | 71.3 | 57.7 | 75.0 | 57.6 | 92.6 | 118.3 |
| **3** | 95.8 | 29.1 | 116.6 | 31.0 | 97.6 | 28.9 | 79.2 | 78.0 | 75.3 | 56.4 | 77.4 | 101.8 |
| **4** | 95.0 | 29.2 | 122.6 | 31.0 | 99.3 | 28.5 | 80.8 | 78.5 | 76.0 | 42.0 | 82.6 | 157.8 |
| **5** | 110.1 | 30.4 | 113.1 | 30.5 | 101.8 | 30.3 | 78.4 | 56.4 | 73.5 | 36.8 | 94.8 | 142.6 |
| **6** | 117.7 | 31.2 | 106.1 | 28.4 | 106.0 | 31.2 | 76.4 | 43.8 | 75.4 | 36.6 | 90.8 | 106.4 |
| **7** | 106.8 | 33.0 | 111.8 | 29.8 | 96.3 | 33.4 | 76.1 | 42.1 | 79.8 | 49.4 | 83.5 | 89.2 |
| **8** | 108.3 | 30.9 | 125.3 | 30.5 | 92.7 | 33.1 | 67.9 | 71.6 | 74.2 | 83.5 | 82.0 | 106.8 |
| **9** | 87.9 | 30.8 | 129.3 | 30.2 | 92.1 | 31.6 | 68.7 | 68.6 | 77.3 | 83.7 | 86.2 | 141.4 |
| **10** | 87.4 | 32.3 | 119.8 | 30.5 | 85.5 | 30.4 | 74.2 | 62.5 | 76.7 | 47.3 | 86.8 | 137.6 |
| **11** | 97.9 | 32.0 | 107.5 | 32.2 | 91.7 | 31.4 | 75.8 | 52.8 | 78.5 | 40.7 | 83.5 | 136.0 |
| **12** | 105.5 | 31.6 | 98.0 | 30.9 | 104.7 | 32.2 | 76.0 | 40.6 | 70.6 | 55.3 | 94.6 | 159.8 |
| **13** | 110.2 | 31.6 | 83.0 | 29.3 | 94.6 | 33.1 | 78.9 | 45.5 | 72.8 | 121.2 | 96.8 | 176.4 |
| **14** | 109.0 | 32.8 | 85.4 | 30.3 | 89.2 | 32.8 | 74.0 | 55.2 | 84.7 | 131.8 | 101.1 | 165.5 |
| **15** | 108.0 | 31.1 | 90.7 | 32.3 | 90.0 | 34.1 | 68.6 | 45.6 | 93.1 | 131.9 | 100.8 | 152.3 |
| **16** | 99.6 | 30.6 | 92.1 | 32.5 | 85.0 | 33.0 | 68.1 | 44.3 | 87.9 | 130.9 | 91.3 | 139.1 |
| **17** | 100.8 | 31.0 | 91.1 | 33.3 | 81.8 | 30.8 | 75.1 | 61.6 | 90.8 | 158.2 | 86.3 | 141.0 |
| **18** | 116.7 | 31.2 | 93.6 | 32.8 | 86.3 | 32.3 | 76.6 | 97.2 | 90.9 | 147.7 | 88.5 | 175.4 |
| **19** | 116.4 | 32.2 | 102.7 | 31.6 | 99.0 | 32.2 | 79.9 | 100.3 | 85.3 | 150.3 | 101.7 | 186.9 |
| **20** | 122.3 | 30.8 | 99.8 | 30.2 | 97.4 | 33.0 | 79.0 | 89.8 | 89.9 | 184.8 | 100.9 | 185.1 |
| **21** | 126.8 | 31.1 | 93.8 | 30.3 | 96.1 | 32.3 | 77.0 | 75.6 | 97.0 | 155.2 | 99.3 | 165.5 |
| **22** | 123.6 | 29.7 | 107.2 | 32.2 | 90.7 | 35.3 | 69.7 | 63.2 | 89.1 | 129.8 | 96.6 | 133.8 |
| **23** | 117.2 | 28.2 | 104.0 | 32.1 | 73.9 | 37.7 | 70.8 | 55.7 | 86.0 | 115.0 | 105.7 | 261.8 |
| **24** | 117.5 | 28.4 | 104.7 | 32.1 | 68.1 | 35.0 | 77.8 | 49.7 | 78.1 | 92.7 | 125.0 | 266.4 |
| **25** | 122.7 | 30.6 | 107.6 | 31.9 | 72.7 | 36.4 | 78.3 | 48.9 | 77.5 | 101.3 | 112.1 | 224.6 |
| **26** | 104.2 | 31.4 | 112.9 | 30.5 | 80.2 | 34.9 | 77.4 | 52.7 | 75.2 | 93.6 | 109.3 | 203.7 |
| **27** | 113.5 | 30.5 | 104.9 | 30.0 | 76.7 | 39.1 | 75.3 | 71.9 | 75.0 | 89.9 | 101.8 | 184.4 |
| **28** | 119.0 | 31.1 | 107.8 | 30.4 | 74.9 | 41.1 | 77.8 | 83.1 | 81.1 | 116.0 | 98.3 | 160.9 |
| **29** | 109.1 | 31.1 | 121.2 | 32.1 | 74.6 | 42.4 | 70.8 | 83.4 | 86.3 | 110.7 | 92.0 | 139.0 |
| **30** | 99.4 | 31.1 | 116.3 | 31.2 | 75.0 | 48.6 | 71.8 | 66.8 | 86.4 | 128.4 | 85.7 | 89.8 |
| **31** | 94.2 | 31.1 | 100.5 | 32.3 | | | 77.3 | 52.9 | | | 77.9 | 84.3 |

**CERTIFICATE OF SERVICE**

I hereby certify that a copy of WG;s Comments on the Value of Distributed Energy Resources ("VDER") study was served this June 14, 2024 on all parties in Formal Case No. 1130 by electronic mail.

Ms. Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
1325 G Street N.W. Suite 800
Washington, DC 20005
bwestbrook@psc.dc.gov

Brian R. Caldwell
Assistant Attorney
General Public Advocacy Section
Office of the Attorney General for D.C.
441 Fourth Street, N.W., Suite 600-S
Washington, D.C. 20001
Brian.caldwell@dc.gov

Sandra Mattavous-Frye, Esq.
Office of People's Counsel
655 15th Street NW, Suite 200
Washington, D.C. 20005
smfrye@opc-dc.gov

Nina Dodge
DC Climate Action
6004 34th Place, NW
Washington, DC 20015
Ndodge432@gmail.com

Kevin Auerbacher, Esq. Telsa, Inc.
1050 K. Street NW Suite 101
Washington, DC 20001
kauerbacher@telsa.com

Christopher Lipscombe, Esq.
General Counsel
Public Service Commission
of the District of Columbia
1325 G Street N.W. Suite 800
Washington, DC 20005
clipscombe@psc.dc.gov

Meena Gowda, Esq.
Deputy General Counsel
DC Water and Sewer Authority 5000
Overlook Avenue, S.W.
Washington, DC 20032
Meena.gowda@dcwater.com

Kristi Singleton, Esq.
Assistant General Counsel
Real Property Division
U.S. General Services Administration
1800 F Street, NW Room 2016
Washington, DC 20405
Kristi.singleton@gsa.gov

Brian R. Greene, Esq.
GreeneHurlocker, PLC
1807 Libbie Avenue, Suite 102
Richmond, VA 23226
BGreene@GreeneHurlocker.com

John C. Dodge