AOBA
APARTMENT AND OFFICE
BUILDING ASSOCIATION OF
METROPOLITAN WASHINGTON

January 24, 2025

By Electronic Filing

Brinda Westbrook-Sedgwick
Commission Secretary
D.C. Public Service Commission
1325 G Street, N.W., Suite 800
Washington, D.C. 20005

Re: Formal Case No. 1180
In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Gas Service

Dear Ms. Westbrook-Sedgwick:

Enclosed for filing please find the Direct Testimony of Timothy Oliver and Bruce Oliver on behalf of the Apartment and Office Building Association in the above-referenced proceeding.

If you have any questions, please contact me by email above or on my cell at (301) 518-9700. Thank you for your attention in this matter.

Sincerely,

Frann G. Francis

Frann G. Francis, Esq.

cc: All parties of record

AOBA (A)

Before the
PUBLIC SERVICE COMMISSION
OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF	)	
	)	
The Application of Washington Gas Light	)	
Company for Authority to Increase Existing	)	**Formal Case No. 1180**
Rates and Charges for Gas Service	)	

VOLUME I OF II: DIRECT TESTIMONY OF AOBA WITNESS TIMOTHY B. OLIVER

January 24, 2025

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Timothy B. Oliver. My business address is 7103 Laketree Drive, Fairfax Station, Virginia, 22039.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am employed by Revilo Hill Associates, Inc., and I presently serve as Vice President and Senior Consultant for the firm.

Q. ON WHOSE BEHALF DO YOU APPEAR IN THIS PROCEEDING?

A. I am appearing on behalf of the Apartment and Office Building Association of Metropolitan Washington (AOBA).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony in this proceeding addresses issues relating to the Washington Gas Light Company's ("Washington Gas", "WG", "the Utility", or "the Company") Application for authority to increase its existing rates and charges for gas service. This testimony responds to portions of the pre-filed direct testimony and supplemental direct testimony, schedules, and responses to data requests that witnesses Burrows, D'Ascendis, Quenum, Baryenbruch, Block, and Tuoriniemi sponsor on behalf of the Company in this proceeding.

Q. PLEASE SUMMARIZE YOUR EXPERIENCE AND QUALIFICATIONS?

A. I have been employed by Revilo Hill Associates, Inc. since 2002. During my employment with Revilo Hill Associates, I have participated in the preparation of a wide range of energy and utility analyses addressing such topics as capital structure, costs of capital, and ROE requirements for gas and electric utilities; utility class cost of service allocations; utility mergers and acquisitions; revenue increase distribution and rate design analyses; the design and operation of revenue decoupling mechanisms; reviews of annual purchase gas cost filings; fuel oil pricing; assessments of issues associated with the siting of proposed LNG facilities, investigation of metering and billing disputes for large building owners, examination of the economics of competitive energy supply alternatives for commercial, governmental, and institutional customers; and evaluation of energy efficiency opportunities in master metered apartment buildings.

I have also prepared or assisted in the preparation of utility rate case analyses and testimony for more than sixty utility electric, gas, and water proceedings in eight different regulatory jurisdictions. Those jurisdictions include the District of Columbia, Maryland, Virginia, Utah, Massachusetts, Rhode Island, Guam, and the Virgin Islands.

I hold a Bachelor of Science degree in Chemistry from the College of William and Mary. I also have a Master of Science degree in Global Energy Management from the University of Colorado Denver Business School, a program that included courses in Regulatory Accounting, Corporate Finance, Energy Economics, Energy Law and Policy, Asset Management, and Strategic Planning.

Q. HAVE YOU PREVIOUSLY APPEARED BEFORE THIS COMMISSION?

A. Yes, I have. I appeared before this Commission in Formal Case Nos. 1103, 1137, 1139,1142, 1156, 1162, 1169, and 1176.

Q. HAVE YOU TESTIFIED BEFORE ANY OTHER UTILITY REGULATORY COMMISSIONS?

A. Yes, I have previously submitted testimony before the Virginia State Corporation Commission, the Maryland Public Service Commission, the Rhode Island Public Utilities Commission, and the Utah Public Service Commission.

Q. WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION AND CONTROL?

A. Yes, it was.

II. OVERVIEW

The Company's Application and supporting testimony and exhibits in this proceeding contain many of the same infirmities and misleading representations found in its filings in Formal Case No. 1169. Both top-down (i.e., high-level financing) and bottom-up (i.e., forecasting methodology) issues infect the reliability of numerous elements of WG's presentations. While some of the Company's proposals are re-packaged and/or renamed, the Company's Application in this proceeding engenders many of the same issues that arose in Formal Case No. 1169, from the Company's choice to pursue private placements of long-term debt to the failure to comply with the Commission's directives for simple linear regressions for the assessment of normal weather. AOBA's review of the Company's Application demonstrates a retrogression, not an improvement, from its filing in Formal Case No. 1169. The Company's attempted compliance with Commission Order No. 21939 to provide an explicit detailing of its affiliate transactions, the Company's Affiliate Cost of Service Study ("ACOSS") has not provided clearer insight into the issues that AOBA elucidated in Formal Case No. 1169.

The Company's Application in this proceeding does not meet the threshold for the Commission to determine the just and reasonableness of the Company's proposed rate increase. Additionally, full consideration of the Company's proposed revenue increase is precluded by Washington Gas's inappropriate and unreliable assessment of normalized gas use. Thus, any revenue requirement approved by this Commission should be applied in the manner proposed by AOBA Witness B. Oliver, which remedies many of the infirmities found in WG's gas use normalization analyses. The Company's problematic determination of normal weather in this proceeding precludes this Commission's ability to set rates on a cost basis.

The Commission's evaluation of Washington Gas' revenue increase request in this proceeding must necessarily address the Company's expanding role as a provider of services to a wide array of regulated and non-regulated WGL Holdings and AltaGas U.S. subsidiaries. This Commission is the only entity that can ensure that District of Columbia ratepayers do not bear costs incurred by Washington Gas in its growing role as a "*service company*."

This testimony addresses the Company's proposed rate of return, capital structure, affiliate issues, and revenue requirements. Issues pertaining to weather normalization, WG's proposed Weather Normalization Adjustment ("WNA"), class costs of service, revenue increase distribution, and rate structure are addressed in the Direct Testimony of AOBA witness Bruce Oliver, Exhibit AOBA (B).

III. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE THE KEY FINDINGS OF YOUR TESTIMONY REGARDING WASHINGTON GAS' APPLICATION AND ITS REVENUE INCREASE REQUEST IN THIS PROCEEDING?

A. The following are key findings that have been derived from my review and analyses of the Direct Testimonies of WG Witnesses Barrows, D'Ascendis, Quenum, Baryenbruch, Block, and Tuoriniemi in this proceeding, as well as from my assessment of the Company's Application, Filing Requirements, responses to Data Requests, and publicly available financial reporting:

- With recent declines in overall market return expectations, WG's currently authorized return has become more attractive to investors and is not reflected in the Company's request.

- Washington Gas' requested 10.50% ROE is **85 basis points above** the ROE approved by this Commission in Formal Case No. 1169.

- As Washington Gas presented in Witness Burrows' direct testimony, the capital structure unreasonably burdens District ratepayers and is, therefore, inappropriate for ratemaking purposes.

- The Company's decisions to de-list from the SEC and to source debt using private placements should be of concern to this Commission since both decisions have reduced transparency.

- The Company's ROE request substantially overstates an appropriately determined equity return requirement for its gas distribution utility operations in the District of Columbia.

- The adjustment to WG's ROE and capital structure presented in this testimony would eliminate **$6.9 million** of WG's $45.6 million revenue increase request in this proceeding without any consideration of other revenue requirements issues.

- The Commission should find that WG's affiliate transactions negatively impact the transparency of the Company's rate-making cost determinations in this proceeding.

- The ACOSS and supporting testimonies are comprised primarily of allocations of costs from WG's parent companies, AltaGas and Washington Gas Holdings. It does not focus on the costs of services that Washington Gas provides to the affiliates.

- Washington Gas' extensive provision of services to both regulated and non-regulated affiliates places this regulated utility in a "**service company**" role that is not typically assumed by regulated utilities. That role and the accounting for affiliate transactions add unnecessary complexity and expense for all parties in the assessment of WG's utility costs of service. More typically, "*service company*" functions are performed by either a division of the parent company or a separate entity which reports directly to the parent company.

- The Commission should find that the provisions of WG's Service Agreement with SEMCO, which conveys oversight responsibilities for any or all elements of Washington Gas operations, customer and business services, should be immediately terminated.

- The Commission should find that the Company has failed to justify the costs SEMCO Energy has allocated to Washington Gas for executive services. It should also be noted that the elimination of WG's service company role could significantly reduce the number of documents in each case that must be classified as confidential.

- Washington Gas' acceptance in its Service Agreement with SEMCO Energy a provision that states: "***the President of SEMCO Energy <u>will provide</u> oversight of the operations, customer and business services of Washington Gas***" is inconsistent with the provisions of the Merger Agreement approved by this Commission.

- Washington Gas has not adequately addressed the manner in which cash flows associated with its affiliate transactions impact its cash working capital requirements, and elements of the lead-lag analyses that WG relies upon to compute its Cash Working Capital requirements for this proceeding are distorted by affiliate service costs.

- The oversight of WG's operations by a SEMCO Executive is inconsistent with the commitment to "local management" of Washington Gas that was agreed upon in the Merger Settlement.

- District ratepayers should not be burdened with costs for oversight of WG's operations by SEMCO Energy executives unless the inclusion of such costs in WG's revenue requirement is coupled with a corresponding reduction in costs for WG's Senior Management.

Q. WHAT RECOMMENDATIONS DO YOU OFFER WITH RESPECT TO WG'S APPLICATION IN THIS PROCEEDING?

A. The following presents a summary of recommendations that I offer for the Commission's consideration in this proceeding. These recommendations are based on the findings discussed above and the discussion of issues and supporting analyses contained in the remainder of this testimony, as well as the accompanying schedules.

1. The Commission should reject Washington Gas's request for a 10.50% ROE and approve a cost of equity for Washington Gas of not more than 9.5%.

2. If the Commission elects to accept the Company's proposed WNA, a downward 25 basis point ROE adjustment to reflect the reduced risk, resulting in an ROE of no more than 9.25%.

3. The Commission, for ratemaking purposes, should adopt AOBA's proposed capital structure of 50% total debt and 50% equity to ensure that District Consumers are not subsidizing AltaGas's extra-jurisdictional and non-utility endeavors.

4. The Commission should require Washington Gas to issue market-based long-term debt based on its stand-alone credit ratings.

5. The Commission should approve an overall rate of return for Washington Gas for the rate effective period of not greater than 7.24%.

6. The Commission should find that WG's affiliate transactions negatively impact the transparency of the Company's rate-making cost determinations.

7. The Commission should direct Washington Gas and AltaGas to terminate Washington Gas' service company role for both WGL Holdings affiliates and AltaGas U.S. affiliates within six months of the conclusion of this proceeding.

8. The Commission should direct Washington Gas to immediately terminate service under the provisions of the Company's service agreement with SEMCO Energy that give SEMCO Energy executives oversight responsibility for WG's operations, customer, and business services.

9. The Commission should determine that Washington Gas has failed to justify the costs SEMCO Energy has charged to Washington Gas for executive services and omit such costs from the Company's requested revenue increase.

IV. DISCUSSION OF ISSUES

Q. HOW IS YOUR DISCUSSION OF ISSUES IN THIS TESTIMONY ORGANIZED?

A. The testimony addresses three elements of the Company's Application. Part A presents AOBA's assessment of the Company's requested overall cost of capital with a focus on the Company's requested return on equity. Part A is comprised of three subparts: (1) Capital Structure, (2) Cost of Equity, and (3) Overall Costs of Capital. Part B contains AOBA's concerns that persist related to Affiliate transactions and relationships. Part C addresses AOBA's proposed adjustments to the Company's proposed revenue requirement.

A. CAPITAL STRUCTURE AND RATE OF RETURN

Q. WHAT IS THE OVERALL COST OF CAPITAL THAT WASHINGTON GAS ASKS THE COMMISSION TO APPROVE IN THIS PROCEEDING?

A. Washington Gas's Application indicates that the Company seeks Commission approval of an overall rate of return of **7.87%**. That requested overall rate of return is premised on a requested **10.50% Return on Equity** ("ROE") and a capital structure that includes **52.49% Common Equity**.

Q. IS WG'S REQUESTED OVERALL RATE OF RETURN REASONABLE?

A. No, it is not. WG's proposed 10.50% ROE is unreasonably and inappropriately high. Further, the Company's computed cost of debt is premised on private issuances that preclude comparison of the costs of debt that Washington Gas can be expected to incur during the rate effective period. Its assumed Common Equity percentage is inappropriately high without any clear demonstration of efforts by Washington Gas' management to minimize the overall cost of capital for District ratepayers.

Q. WHAT IS THE BASIS FOR YOUR ASSESSMENT THAT THE COMPANY'S REQUESTED RETURN ON EQUITY IS UNREASONABLY AND INAPPROPRIATELY HIGH?

A. The cost of equity analyses that Washington Gas Witness D'Ascendis presents: 1) are outdated in light of changes in market conditions since his May 2024 retrieval of financial information for his analyses; 2) incorporates financial data that is out of line with other publicly available sources; and 3) is overly reliant on his CAPM and ECAPM analyses.

Q. AT WHAT LEVEL SHOULD THE COMPANY'S AUTHORIZED ROE BE SET IN THIS PROCEEDING?

A. The Commission should set the authorized ROE for Washington Gas at 9.50%. If the Commission elects to approve the Company's proposed WNA, Witness D'Ascendis testifies that a WNA would lower the Company's comparative risk, thus warranting a reduction in the ROE.[1] AOBA proposes that a 25 basis point downward adjustment would be gradual and reasonable. This would result in an ROE for WGL of 9.25% if a WNA is accepted.

1. Capital Structure

Q. WHAT FACTORS SHOULD THE COMMISSION CONSIDER WHEN ASSESSING THE APPROPRIATE CAPITAL STRUCTURE FOR RATEMAKING PURPOSES IN THIS PROCEEDING?

A. Any determination regarding the appropriateness of a proposed equity component for WG's capital structure for ratemaking purposes must reflect a balancing of at least four considerations. Those considerations include:

[1] WG Exhibit (C), page 48, lines 19-23.

- ✓ Does the proposal reflect a reasonable attempt to minimize the overall costs to ratepayers of financing the Company's utility operations?

- ✓ Does the proposal support the financial stability and health of the Company's utility operations?

- ✓ Does the proposal inappropriately foster subsidization of the activities of non-regulated affiliates?

- ✓ Does the proposal provide the Company with substantial opportunities to improve its profitability by utilizing an actual capital structure that differs from the capital structure approved for ratemaking purposes?

Q. WHAT CAPITAL STRUCTURE DOES WG PROPOSE TO USE FOR RATE-MAKING PURPOSES IN THIS PROCEEDING?

A. The pre-filed direct testimony of WG Witness Burrows at page 2, presents the Company's recommended capital structure. That Capital Structure includes the following components:

Common Equity	$2,344,085	52.486%
Long-Term Debt	1,915,107	42.881%
Short-Term Debt	206,965	4.634%
Total Debt	$2,344,085	47.514%
TOTAL	$4,466,148	100.00%

Q. HAS WG ADEQUATELY EXPLAINED OR JUSTIFIED ITS PROPOSED CAPITAL STRUCTURE?

A. No, it has not. The Direct Testimony of Witness Burrows asserts that WG's financial strategy has been developed to enable the Company to *"A sound financing strategy [allows a company] to fund its capital requirements at* ***a***

reasonable cost and to *remain flexible in accessing financial markets, even during periods of* economic *uncertainty or unexpected liquidity requirements*."[2] (Emphasis Added). However, the witness offers no quantitative basis for assessing the reasonableness of the costs that result from the Company's financing strategy. Nor does Witness Burrows offer any sensitivity analysis to demonstrate the manner in which the Company's financing costs and/or its access to financial markets would change with changes in planning assumptions or changes in market conditions.

Q. IS THE CAPITAL STRUCTURE THAT WG PROPOSES IN THIS PROCEEDING REASONABLE AND APPROPRIATE FOR RATEMAKING PURPOSES?

A. Since Formal Case No. 1142, Washington Gas and its parent AltaGas have experienced material changes in their financial profiles. The utilization of Washington Gas Light Company as a provider of affiliate services illustrates that the operational functions provided have eroded the independent nature of Washington Gas Light Company's financial profile. In light of this co-mingling the Commission must ensure that Washington Gas Light Company's capital structure is not leveraged by Washington Gas' parent company (AltaGas) and does not result in increased costs to District ratepayers to benefit the parent company's financial profile. However, given the Company's overall capital spending plans for the three jurisdictions in which it provides retail distribution service, further

[2] Exhibit WG (B), page 3.

issuances of debt by Washington Gas prior to or during the rate effective period appear unavoidable. Thus, any consideration of a capital structure that exceeds the equity percentage that is employed by its parent, AltaGas, that Washington Gas proposes in this proceeding should be balanced by consideration of additional debt that Washington Gas will need to issue to fully fund its plans for significant capital spending in each of the jurisdictions in which it provides service. Debt Issuances, whether in the form of private placements or obtained in the public markets, may not be sustainable as AltaGasUS continues to pursue the sale of assets. Furthermore, the leveraging of Washington Gas' common equity to lower the overall costs of capital enjoyed by AltaGasUS non-regulated affiliates should not be borne by District ratepayers. In this proceeding, Washington Gas has provided no meaningful information for this Commission to determine that "reasonable" efforts have been made to ensure that Washington Gas' capital requirements have included any considerations for minimizing the costs Washington Gas proposes to impose on District ratepayers.

Q. DOES THE FACT THAT THE COMPANY'S PROPOSED COMMON EQUITY PERCENTAGE FALLS WITHIN THE RANGE SPECIFIED IN THE MERGER COMMITMENTS SET FORTH IN FORMAL CASE NO. 1142 JUSTIFY COMMISSION APPROVAL OF THAT PERCENTAGE?

A. No. The range from 48% to 55% set forth in Merger Commitment 32 identifies extremes that should not be exceeded. That range says nothing about the reasonableness and appropriateness of any specific common equity percentage for which WG may seek approval in a subsequent rate case. Furthermore, Washington Gas has not presented any testimony illustrating that a common equity percentage, within the range of the merger commitment but lower than its requested 52.49%, would inhibit the Company's ability to flexibly meet its capital requirements at a reasonable cost to ratepayers.

Q. WHAT CRITERIA SHOULD BE USED TO ASSESS THE APPROPRIATENESS OF THE COMMON EQUITY PERCENTAGE THAT WASHINGTON GAS PROPOSES IN THIS PROCEEDING?

A. The Commission should seek to establish a capital structure and a common equity percentage that minimizes the capital costs that District ratepayers are asked to bear while maintaining reasonable financial flexibility to access financial markets to meet the Company's capital requirements. Given that Washington Gas no longer issues publicly marketed common equity or publicly marketed debt issuances, the appropriate common equity percentage for Washington Gas is primarily a function of the Company's need to maintain the ability to access private placement for additional debt at reasonable cost. Due to the opaque nature of private placements, the Commission should place paramount importance on the minimization of costs to District Ratepayers.

Q. HOW DOES THE COMMON EQUITY PERCENTAGE THAT WG PROPOSES IN THIS PROCEEDING COMPARE WITH THE COMMON EQUITY PERCENTAGE IN FORMAL CASE NO. 1169?

A. In Formal Case No. 1169 the Commission provided Washington Gas 53.68% of Common Equity in its capital structure. That is 119 basis points above the Company's requested Common Equity percentage in this proceeding. While the lower Common Equity percentage proposed is an improvement, Washington Gas provides no explicit operational or market drivers that quantify how its proposed equity percentage would provide benefits to ratepayers in the District compared to a lower percentage of common equity.

Q. WHAT SUPPORT DOES WASHINGTON GAS OFFER FOR ITS REQUESTED COMMON EQUITY PERCENTAGE IN THIS PROCEEDING?

A. The Company's recommended capital structure is premised on the assessment of the Company's "Average 4-Quarter Capital Structure" that is presented in Witness Burrows' Exhibit WG (B)-2, page 1.

Q. DOES THE ANALYSIS PRESENTED IN EXHIBIT WG (B) OFFER ANY ASSESSMENT OF THE IMPACT ON RATEPAYER COSTS OF WG'S PROPOSED INCREASE IN ITS COMMON EQUITY PERCENTAGE?

A. No, it does not. In the context of the magnitude of the large overall revenue increase that Washington Gas seeks in this proceeding, the absence of quantitative analyses of the impacts of WG's proposed Common Equity percentage on the Company's revenue requirement and rates should not be ignored. An unnecessarily high equity percentage has two adverse impacts. First, considering the much higher effective cost of common equity, increases in the portion of the Company's assumed capital structure for ratemaking purposes of common equity, directly increases the level of the Company's overall revenue requirement and cost of capital. Second, an unnecessarily high Common Equity percentage allows the Company to enhance its effective return on equity by making greater use of lower-cost debt alternatives.

Q. DOES THE ANALYSIS PRESENTED IN EXHIBIT WG (B)-2 REFLECT THE COMPANY'S ACTUAL CAPITAL STRUCTURE BY CALENDAR QUARTER FOR THE TEST YEAR?

A. No, it does not. The Company's recommended capital structure is premised on the assessment of an "Average 4-Quarter Capital Structure" that does not reflect the Company's actual capital structure for any calendar quarter. Instead of presenting the Company's actual capital structure for each quarter, Witness Burrows' Exhibit WG (B)-2 substitutes an annual average amount of short-term debt for WG's actual amount of Short-Term Debt for each quarter. That hides significant quarter-to-quarter fluctuations in the Company's actual use of Short-Term Debt. Exhibit WG (B)-3, page 2 of 3, Column C, indicates the Company's actual average daily Short-Term Debt balances by month for the Test Year. From that data, large fluctuations in the actual average daily Short-Term Debt balances can be observed. Over the 12 months of the Company's test year, short-term debt balances ranged from a high of approximately $320 million in September 2023 to a low of $98 million in March 2024. That level of month-to-month variations decreases the weight this Commission should place on the Company's average short-term debt presentation. It demonstrates that the Company does utilize an operational capital structure that is noticeably different from the capital structure utilized for ratemaking purposes.

Q. WHAT CONCERNS DO YOU HAVE REGARDING WASHINGTON GAS' DECISION TO PURSUE PRIVATE PLACEMENTS OF LONG-TERM DEBT ISSUANCES AS OPPOSED TO PUBLICLY MARKETED LONG-TERM DEBT?

A. Private placement debt issuances are not appropriate for proxy group comparisons; by definition, private placements are both opaque and not market based. If Washington Gas and its parent company have to resort to private placement debt issuances, then it should be understood that they are price-takers, and may be susceptible to affiliate contagion, and cannot achieve market-based rates for long-term debt, which is in violation of its merger commitments and is at the expense of District ratepayers. Further, a self-selected narrow proxy group should not be viewed by this Commission as a reasonable justification for Washington Gas' cost of long-term debt. The contrasting differences in the rates and term lengths of its 2022 and 2023 debt issuances demonstrate that costs of debt have diverged and increased since the consummation of the merger. District consumers should not pay a premium for Washington Gas's decisions or its holding company's inability to access public debt markets.

Further, AltaGas, which controls the timing, size, and terms of debt issuances, has a credit rating below that of the utility. If the independence of Washington Gas' financial planning is to be believed, the need for private placements would be avoided. Private placements impede this Commission's ability to enforce the merger commitments of no increased cost of debt due to the Merger. The Company's election to pursue private placements is both a sign of the erosion of a storied utility's credit ratings due to new foreign management and an attempt to avoid regulatory commitments made for the merger's approval.

Finally, this Commission should require Washington Gas to issue long-term debt in the public debt markets based on its credit rating on a stand-alone basis. This would be consistent with the merger commitments, which hold Washington Gas accountable for increased debt costs due to the merger and prevent the comingling of funds.

Q. DOES THE ANALYSIS PRESENTED IN EXHIBIT WG (B)-5 PROVIDE USEFUL GUIDANCE WITH RESPECT TO THE CAPITAL STRUCTURES USED FOR RATEMAKING PURPOSES FOR PEER UTILITIES?

A. No. Exhibit WG (B)-5 reflects actual capital structure data where the actual mix of capital that a utility chooses to employ can vary noticeably from the capital structures that regulators in other jurisdictions have used for ratemaking purposes. Moreover, Exhibit WG (B)-5 depicts a wide range of **actual** common equity percentages without any assessment of the factors that explain the reasons for the observed differences in common equity percentages across companies. It does not reflect the capital structures that regulators in other jurisdictions have found appropriate for utilities operated by the listed companies.

Thus, the fact that WG's calculated "median" common equity percentage of 52.49% appears to correspond closely with WG's proposed common equity percentage in this proceeding is of little, if any, significance.

Q. HOW DOES WG'S REQUESTED CAPITAL STRUCTURE COMPARE WITH THE CAPITAL STRUCTURE USED BY ITS PARENT COMPANY, ALTAGAS, LTD?

A. AOBA (A)- Attachment B, AltaGas' Third Quarter 2024 Financial report, indicates that AltaGas maintains a much higher debt ratio and less equity than WG requests in this proceeding. In the third quarter of 2024, Debt represented 55.1% of the overall capital used by AltaGas Ltd.[3] When Washington Gas' capitalization is subtracted from AltaGas' Q3 2024 capital structure for all other activities (including SEMCO's regulated operations), it is found to comprise nearly **57.5% Debt** and only about 42.5% Equity (with equity defined to include Common Stock, Preferred Stock, and Minority Interest funding). These calculations are presented in Exhibit AOBA (A)-2.

AltaGas' maintenance of greater percentages of equity in regulated utility operations than for its overall operations reflects a strategy that leverages the more secure returns of its regulated entities to obtain lower-cost financing for competitive business enterprises with generally greater risk. This use of financial leverage has the effect of raising costs to Washington Gas ratepayers while improving

[3] AOBA (A)- Attachment B, AltaGas' Third Quarter 2024 Financial report.

AltaGas' competitive position in other non-regulated markets and enhancing the profitability of its non-regulated businesses. Assuming AltaGas raises debt and equity capital at the same rates for both its regulated and non-regulated operations, the differences in capital structure between AltaGas and Washington Gas produce a lower overall cost of capital for AltaGas' non-regulated operations.

Q. WHAT CAPITAL STRUCTURE SHOULD THE COMMISSION APPROVE FOR RATEMAKING PURPOSES FOR WASHINGTON GAS IN THIS PROCEEDING?

A. For ratemaking purposes, the Commission should approve a capital structure of 50% common equity and 50% total debt for Washington Gas. That ratio is within merger commitment 32[4], would benefit and protect District of Columbia consumers, and has not been demonstrated by the Company that it would cause financial harm to Washington Gas' ability to obtain capital at reasonable rates. While the Commission may determine a capital structure for rate-making purposes, Washington Gas, as discussed above, may elect to utilize an alternative operational capital structure. Exhibit AOBA (A)-2 demonstrates that the parent company's capital structure leverages Washington Gas' utility capital structure to improve AltaGas' overall debt ratio. District ratepayers incur greater costs under this paradigm. For these reasons, a rate-making capital structure with an even distribution of equity and debt would provide some level of mitigation to Washington Gas' proposed increase in capital costs for District ratepayers.

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[4] Formal Case No. 1142, Appendix A, Merger Commitment 32.

2. Cost of Equity

Q. DO YOU HAVE ANY GENERAL OBSERVATIONS REGARDING THE ROE ANALYSES THAT WASHINGTON GAS HAS SUBMITTED IN THIS PROCEEDING IN SUPPORT OF ITS REVENUE INCREASE?

A. I do. With respect to the Company's ROE, Washington Gas asks for the Commission's approval of a 10.50% return on equity. That is a rather significant **85 basis points** above the 9.65% ROE level that this Commission approved for Washington Gas in Formal Case No. 1169 and reflects no consideration of gradualism in the adjustment of authorized ROEs. It is also 85 basis points above the 9.65% authorized ROE established for Washington Gas in the Company's most recent base rate case in Virginia, which was decided on August 29th, 2023.[5] Additionally, the most recent ROE determination by the Marland Public Service Commission in Case No. 9704 authorized a 9.5% return on equity, 100 basis points below WG's request in this proceeding.[6] Moreover, even considering the recent interest rate volatility, WG's currently authorized ROE now outpaces current market return expectations. When consideration is given to the effects of the Covid-19 pandemic on the District's economy and the Company's failure to meaningfully reduce hazardous leaks on its District of Columbia distribution system, an increase in the equity return for WG's sole shareholder, AltaGas, cannot be justified.

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[5] Virginia State Corporation Commission, Case No. PUR-2022-00054, FINAL ORDER, dated August 29, 2023, page 5.

[6] MD PSC Order No. 90943, page 139, issued on December 14, 2023.

The proxy group companies that Witness D'Ascendis employs to support his ROE recommendation reflect a reasonable sample of the few holding companies with substantial gas distribution operations for which public market data is available at this time. Unfortunately, this is due to the continued M&A activity in the utility industry, including AltaGas' acquisition of Washington Gas, which has diversified the risk profiles of many of the largest natural gas distribution utilities. The vast majority of natural gas utilities are now subsidiaries of diversified energy holding companies like AltaGas. The large pool of investors who these companies seek to raise equity from only have the option to invest at the holding company level, therefore reducing the number of available companies with large gas distribution utility operations available for comparison. This constraint does not ameliorate the discrepancy of the risks between a holding company and the comparable risk of a gas distribution utility, such as Washington Gas. Witness D'Ascendis' proxy group is comprised of utility-holding companies with investment portfolios that often include significant non-utility and non-price-regulated business activities. The reliance on diversified energy holding companies without deleveraging the regulated and unregulated operations continues to lead to ROE analysis results that represent risks greater than that of a stand-alone gas distribution operation.

Q. WHAT RATE OF RETURN ON COMMON EQUITY ("ROE") DOES WG WITNESS D'ASCENDIS RECOMMEND IN THIS PROCEEDING?

A. Witness D'Ascendis' Direct Testimony recommends that the Commission approve an ROE of **10.50%.**[7] His recommendation is based on his assessment that the Company's ROE should fall within a range of 9.99% to 11.63%.[8]

Q. WHAT SUPPORT DOES WITNESS D'ASCENDIS OFFER FOR THE COMPANY'S REQUESTED 10.50% COST OF EQUITY?

A. Witness D'Ascendis presents cost of equity analyses that are developed using four equity cost estimation methods. Those methods include (1) a discounted cash-flow ("DCF") model, (2) a traditional Capital Asset Pricing Model ("CAPM"), and (3) a Bond Yield Risk Premium Model ("RPM").[9] After his presentation of the results of those models, Witness D'Ascendis also applies these three methods to a proxy group comprised of non-price regulated companies.

Q. DOES WITNESS D'ASCENDIS CONSISTENTLY APPLY THE STANDARDS ESTABLISHED FOR ROE DETERMINATIONS IN *HOPE* AND *BLUEFIELD*?

A. Yes, but only in part. Although he asserts that his analyses and recommendations consider "*the Company's business risk relative to the proxy group…*" the continuation of that sentence states that the proxy group is comprised of "*comparable companies*." The differences in risk between the utility holding

[7] Exhibit WG (2C), page 5.
[8] Ibid.
[9] Exhibit WG (2C), page 4.

companies that comprise his selected proxy group and the risk of WG's regulated utility operations are significant and must not be ignored. However, investors only vehicle to assess relative risk are utility holding companies.

Witness D'Ascendis also does not consider the impacts of changes in industry structure and regulatory policies over time on gas distribution utility risk and ROE requirements. There is now only one investor in Washington Gas. That is AltaGas, whose investors base their investment decisions on the risks and returns offered more broadly by AltaGas, not WG's gas distribution utility operations. In fact, there are numerous examples of the financial community's recognition of greater business and financial risk in utility holding companies than in their distribution utility subsidiaries. The Commission must further recognize that the comparable risk standards set forth in the *Hope* and *Bluefield* decisions can be satisfied even when differences in risk between utility holding companies and their distribution utility subsidiaries may be addressed in regulatory cost of equity determinations for distribution utilities by appropriately acknowledging the lower risk associated with the regulated gas distribution operations, which is supported by Washington Gas Light Company's favorable investor grade credit rating compared to AltaGas.

I. DCF Analyses

Q. ARE WITNESS D'ASCENDIS' CONSTANT GROWTH DCF ANALYSES REASONABLE?

A. Only in part. Witness D'Ascendis' DCF analysis in Exhibit WG (C)-3 is an improvement from his previous presentations with the elimination of multiple averages of stock price time periods, with the utilization of 60-day average stock prices, and the elimination in his presentation of "mean low" and "mean high" results. However, Witness D'Ascendis' DCF is unduly influenced by the financial information provided by Value Line. Value Line's projections of earnings are significantly different than earnings growth projections offered by other financial information providers such as Zacks, Seeking Alpha, and Finviz and should not be relied upon.[10]

Q. OTHER THAN THE FACT THAT THE VALUE LINE ESTIMATES OF EARNINGS GROWTH DIFFER FROM THOSE FROM OTHER SOURCES, WHY SHOULD THE VALUE LINE EARNINGS GROWTH ESTIMATES BE DISREGARDED?

A. My analysis relating to the Value Line earnings growth estimates on which Witness D'Ascendis has relied raises significant concerns. It appears that Value Line's earnings growth estimates have not been computed in a manner that eliminates consideration of abnormal or one-time adjustments for earnings. Further, Value

[10] The three sources of financial data utilized in my ROE analyses are publicly available and tightly correlated.

Line's deviation from other publicly available financial information persists in Value Line's "adjusted betas." Value Line provided data has become an outlier and should be given significantly less weight by this Commission in its determination of Washington Gas' return on equity.

ii. CAPM Analyses

Q. HOW SHOULD THE COMMISSION ASSESS THE RISK PREMIUM ANALYSES THAT WITNESS D'ASCENDIS PRESENTS ON BEHALF OF WG?

A. Witness D'Ascendis offers a number of scenarios for the CAPM and Bond Yield Plus Risk Premium analyses that are all premised on two estimates for 30-year U.S. Treasury Bond yields: the current rate and a near-term projected rate. Witness D'Ascendis uses a current 30-year U.S. Treasury Bond yield of 5.13% and a projected rate of 5.17%.[11]

Q. ARE THERE PROBLEMS ASSOCIATED WITH WITNESS D'ASCENDIS' CAPM ANALYSIS?

A. Yes. Witness D'Ascendis' presentation fails to openly discuss differences in measures of Beta that he employs. The Commission should recognize that Beta coefficients have been developed as measures of the volatility of a company's stock price relative to the volatility of the broader market. However, that focus on relative stock price volatility only addresses one element of a company's risk.

[11] WG Exhibit (D), page 31.

Other forms of financial risk, operating risk, and market risk that a company may face in the production and marketing of its products and services are not addressed. This is important since regulated distribution utilities often are provided mechanisms (e.g., revenue and/or cost adjustment mechanisms) to insulate them from various forms of risk for which competitive enterprises have no protection.

The Commission is also asked to appreciate that Beta coefficients are key inputs to CAPM analysis. Yet, there are numerous alternative methods for computing Beta coefficients, and some of those alternatives can noticeably alter the ROE estimates that are derived from CAPM models. It is, therefore, imperative to understand differences in: (1) Beta computation methods; and (2) the time periods over which different measures are computed.

Q. WHAT IS YOUR ASSESSMENT OF WITNESS D'ASCENDIS'S BOND YIELD PLUS RISK PREMIUM ANALYSIS?

A. Witness D'Ascendis' Bond Yield Plus Risk Premium analysis engenders a number of concerns from both conceptual and practical perspectives. His efforts to estimate a regression relationship are based on data for A2-rated bonds and measures of 30-year Treasury yields quarterly from 1928 through 2023 (i.e., roughly 95 years). Over that period, there have been substantial, and in some respects dramatic, changes in the utility industry, regulatory policies, financial market conditions, and the ownership of distribution utilities. Natural gas has been fully deregulated at the wellhead, gas transportation markets have been opened to competition, and gas service offerings are increasingly unbundled. There has also been a dramatic consolidation of utility ownership through numerous mergers and acquisitions that have resulted in gas distribution utilities becoming subsidiaries of larger, and generally more diversified, holding company parents. Regulatory practices have also changed to allow increased numbers of rate adjustment mechanisms and cost deferrals. Also, in many jurisdictions, utility revenues have been either fully or partially decoupled in a manner that provides increased assurance of revenue recovery. In addition, the Federal Reserve has become more active as a manager of the economy through its monetary policies. As a result of such changes, the risks faced by gas distribution utilities today differ substantially from those faced by companies providing the same utility services in prior decades. Yet, Witness D'Ascendis offers no assessment of the impacts of those changes on his analysis and the proper interpretation and application of the results of his analysis.

The Bond Yield Plus Risk Premium methodology employed by Witness D'Ascendis is premised on the notion that changes in utility equity return requirements over time are related to changes in the costs of risk-free investments. However, nowhere in that model is there an ability to account for changes in the risk profiles of the utilities for which ROE determinations are rendered. Instead, users of the Bond Yield method must implicitly assume that either (1) there have been no changes in utility risk profiles over time or (2) the risks faced by all utilities have generally affected all utilities in a uniform manner over time. Neither of those assumptions is reasonable. Again, it is inappropriate for Witness D'Ascendis to assert that he has considered the comparable risk standards of the *Hope* and

Bluefield decisions when he does not account for changes in the risk profiles of companies within the industry over time.

In terms of more practical considerations, Witness D'Ascendis provides no indication of how the measure of the risk-free rate (i.e., the 30-year U.S. Treasury Bond Yield) that he associates with individual rate case decisions were determined. U.S. Treasury Bond yields measured as of the date of issuance of orders would not be a measure of yields that regulators could have considered in reaching their ROE determinations. If the measures of bond yields for individual rate case ROE determinations that Witness D'Ascendis uses in his regression equation were not actually considered by regulators when making their ROE determinations, then the relationship estimated by Witness D'Ascendis may represent little more than coincidence (e.g., a correlation between stock market performance and the length of hemlines on women's dresses). The identification of a statistical correlation does not necessarily imply a causal relationship, nor does it necessarily imply that the identified relationship will continue to hold as we move forward in time. In other words, correlations developed from past relationships may not be reliable predictors of future outcomes.

In past proceedings, this Commission has primarily relied upon DCF analyses to determine equity return requirements. However, before relying on regression-based Bond Yield Plus Risk Premium analyses, the Commission must consider the limitations discussed above. Washington Gas would need to provide more detail regarding assumptions and inputs.

iii. AOBA Cost of Equity Analyses for WG

Q. PLEASE DESCRIBE THE COST OF EQUITY ANALYSES THAT YOU HAVE DEVELOPED FOR THIS PROCEEDING?

A. In addition to my review of Witness D'Ascendis' cost of equity presentation, my efforts to estimate an ROE for WG in this proceeding include the computation of DCF and CAPM analyses. Those analyses are presented in Exhibit AOBA (A)-1, pages 1 through 5. For my analyses, I have used the same proxy group chosen by Witness D'Ascendis, even with my past stated concerns regarding the small size of the proxy group and its representation of the risk of holding companies, not distribution utilities such as WG.[12]

Q. HOW ARE YOUR DCF ANALYSES PRESENTED?

A. The detail of my DCF analysis is presented on page 2 of Exhibit AOBA (A)-1. That analysis employs annual high and low stock price data and earnings growth projections from Zacks, Seeking Alpha, and Finviz in a traditional Constant Growth DCF model. Overall proxy group DCF results are summarized for each source of earnings growth estimates on page 1, lines 1-4 of Exhibit AOBA (A)-1.

[12] As a result of recent mergers and acquisitions, few alternatives remain for the construction of gas utility proxy groups.

Q. WHAT BETA COEFFICENTS DID YOU UTILIZE IN THE DEVELOPMENT OF YOUR CAPM ANALYSES?

A. I utilized three different estimates of beta coefficients in my analyses: Zacks, Seeking Alpha, and Finviz.

Q. WHAT IS AN APPROPRIATE RISK-FREE RATE FOR USE IN ROE DETERMINATIONS FOR THIS PROCEEDING?

A. The risk-free rate used to estimate the required ROE for Washington Gas' Distribution Utility operations should be based on recent actual 30-year treasury rates. With that and the current environment of recent interest rate volatility, I have selected the recent 30-year treasury rate, as of January 9th, 2025, of 4.92% for my CAPM analysis.

Q. WHAT IS THE BASIS FOR THE 9.50% ROE THAT YOU RECOMMEND?

A. My presentation of AOBA's ROE recommendation for WG is supported by the analyses presented in Exhibit AOBA (A)-1. Exhibit AOBA (A)-1, page 1, summarizes those analyses and presents AOBA's ROE recommendation. Exhibit AOBA (A)-1, pages 2 through 5, presents AOBA's ROE analyses utilizing the same proxy group as the Company. The average of AOBA's DCF results is 9.81%. The average of AOBA's CAPM results is 9.22%. The results of AOBA's cost of equity analyses combined is 9.52%.

Even without the inclusion of the Company's currently authorized ROE in the results of my analyses, the average of the above ROE determinations produces a rounded result of 9.50%, as shown in Exhibit AOBA (A)-1, page 1. This clearly supports a downward adjustment to the Company's currently authorized 9.65% ROE.

3. Overall Cost of Capital

Q. WHAT IS THE COMPANY'S PROPOSED OVERALL COST OF CAPITAL?

A. Washington Gas proposes an Overall Cost of Capital of 7.87%. That overall cost of capital reflects a requested return on equity of 10.50%, or an increase of 85 basis points over the ROE determined in the Final Order No. 21939 in Formal Case No. 1169.

Q. DOES AOBA SUPPORT THE COMMISSION'S APPROVAL OF WG'S REQUESTED 7.87% OVERALL COST OF CAPITAL?

A. No. AOBA does not support either the weighting of the debt and equity components in the Company's proposed capital structure or the Company's determinations of the cost rates for those capital structure components. AOBA recognizes that financial market conditions have changed. However, AOBA finds the Company's requested Overall Cost of Capital is excessive.

Q. WHAT IS THE OVERALL COST OF CAPITAL THAT RESULTS FROM YOUR ROE AND CAPITAL STRUCTURE RECOMMENDATIONS?

A. The combined impact of the ROE and capital structure recommendations that I present would lower WG's overall rate of return ("ROR") to 7.24%. That result is shown in AOBA Exhibit (A)-3.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE APPROPRIATE COST OF EQUITY AND CAPITAL STRUCTURE FOR WASHINGTON GAS?

A. My analyses suggest the Company's ROE should be no more than 9.5%. However, just as commissions are encouraged to reflect gradualism in their adjustment for rates for utility customers, it would be reasonable for this Commission to reflect a measure of gradualism in its adjustment of WG's ROE. My recommended ROE for the Company in this proceeding is 9.50%, which represents a gradual adjustment. That represents the elimination of 15 basis points, a gradual adjustment, from WG's currently authorized ROE (i.e., 9.65% in Formal Case No. 1169). Although current market conditions could justify a larger downward adjustment to WG's ROE, the more gradual adjustment proposed provides for greater continuity in regulatory determinations and avoids a large one-time change.

Adjustment of the Company's requested ROE to a level that more reasonably reflects current market conditions and WG's risk profile, and utilizing AOBA's recommended ratemaking capital structure, results in approximately a $6.9 million reduction to WG's requested revenue increase in this proceeding. As discussed in detail later in Part C of this Testimony and in the Direct Testimony of

AOBA Witness Bruce Oliver, there are a litany of further reductions to WG's requested revenue requirement that should serve to mitigate harm to DC consumers.

B. AFFILIATE ISSUES

Q. WHY DOES THIS COMMISSION NEED TO CONTINUE TO ADDRESS WASHINGTON GAS' AFFILIATE TRANSACTIONS?

A. Washington Gas' affiliate transactions have expanded significantly since the Merger closed. Both the dollar amounts of affiliate transactions and the number of affiliated entities for which WG provides services and/or receives services have increased noticeably.

1. <u>Shortcomings of WG's Attempted ACOSS</u>

Q. HAVE YOU REVIEWED THE COMPANY'S FILED ACOSS AND SUPPORTING MATERIALS?

A. Yes, I have.

Q. DOES THE COMPANY'S PRESENTATION OF AFFILIATE TRANSACTIONS REMEDY AOBA'S CONCERNS?

A. No. The Company's presentations of Witnesses Baryenbruch and Block discuss the affiliate and Corporate services provided to Washington Gas, respectively.

Both Testimonies only discuss a singular dimension of the Affiliate issues (i.e., what is incurred by WG, not the costs for services provided by WG to its affiliates). Both are monodirectional and focus primarily on the services and perceived values of the services rendered to Washington Gas. This narrow presentation generally ignores the issues raised by AOBA in Formal Case No. 1169 regarding the services that Washington Gas Light Company provides to its corporate affiliates and parent Company (AltaGas). While Witness Quenum states that “all transactions are cash closed on a monthly basis.” However, included in her testimony is an acknowledgment that corrections, reclassifications, and other adjustments persist and are part of the allocation process. That caveat demonstrates the lack of specificity and erodes the confidence that can be placed on the Company’s presented ACOSS.

Furthermore, the Modified Massachusetts Formal used by both Witnesses Baryenbruch and Block is applied to a set of factors different from those described in the Company’s most recent CAM filing, upon which Witness Quenum applies in the application of allocation of “pooled costs.” The aggregation of costs into pools and the majority of those costs being allocated using composite allocation factors. This does not provide insight into the specific details of the costs, which are otherwise treated as homogeneous. AOBA’s concerns from Formal Case No. 1169 included the ability to verify the accuracy and appropriateness of source data of discrete costs between affiliates. The Company’s approach in this proceeding does not elucidate specific transactions; instead, it’s an exercise of aggregation and allocation that is not cost-based or provides verifiable documentation of the actual costs incurred by each affiliate.

Additionally, the absence of discussion or recognition of the services provided by the utility (i.e., Washington Gas Light Company) only provides half the picture of the increasing reliance on the regulated utility's insidious role as the financial guarantor and service provider to all the subsidiaries under AltaGas' corporate umbrella.

As discussed above in part A of this testimony, it is clear that AltaGas is leveraging the financial attributes of its largest regulated subsidiary (Washington Gas Light Company). This leveraging reflects an undue burden to ratepayers when the Company is allowed significant latitude to make large retroactive adjustments.

Q. SHOULD THE COMMISSION PLACE ANY WEIGHT ON THE AFFILIATE INFORMATION PROVIDED IN THIS PROCEEDING?

A. Little, if any, due to the solely top-down presentations from Witnesses Baryenbruch and Block., as well as Witness Quenum's cryptic ACOSS presentation. All three of these presentations place significant focus on aspects that were not the focus of AOBA's concerns in Formal Case No.1169. At the same time, AOBA can understand that certain corporate synergies may reduce operational and corporate costs. The presentations provided do not alleviate or elucidate the concerns AOBA has raised regarding Washington Gas' subsidization of AltaGas' subsidiaries at the expense of District ratepayers.

Q. IS WASHINGTON GAS' EMPLOYMENT OF THE MODIFIED MASSACHUSSETS FORMULA (MMF) CONSISTENT OR REASONABLE?

A. Traditionally, the MMF is an allocation of last resort, applied to miscellaneous items or costs that cannot be directly or proportionally assigned. Washington Gas' reliance on the use of a Modified Massachusetts Formula ("MMF") to assess the responsibilities of WGL Holdings and Washington Gas for costs associated with AltaGas Corporate Services is overly broad in its application. As described in the Company's most recent CAM filing, the majority of affiliate costs utilized the MMF allocation methodology. Witnesses Baryenbruch and Block utilize an MMF based on EBITA, Relative Payroll Costs, and Relative Property. This is the basis for these witnesses' assessment of the value of services provided to Washington Gas from its affiliates and corporate services. In contrast, WG's ACOSS, sponsored by Witness Quenum, employs an adjusted MMF consisting of Average Invested Capital, Adjusted Net Revenue, and Labor. This discrepancy in the MMF precludes a direct comparison of the Company's affiliate-related testimonies. The formulation of the MMF utilized by Witness Quenum provides little assurance that costs allocated to Washington Gas and its ratepayers will be insulated from the fluctuations in changes of the relative earnings of other entities subject to the MMF allocations. This is highly inappropriate. Under no conditions should the costs allocated or assigned to Washington Gas be a function of the level of earnings recorded by non-utility entities within the AltaGas family.

The Application of any variation of the Modified Massachusetts Formula is traditionally an allocation of last resort. Its application should be limited to a marginal amount of costs that cannot be directly assigned or allocated using more specific cost-based allocation relationships. WG's ACOSS relies on its Adjusted MMF to allocate a majority of its affiliate costs. This is in part due to its decision to pool costs that are then adjusted by a dubious "burden rate." further, the Testimonies of Witnesses Baryenbruch and Block, in their assessment of the affiliate and corporate costs to Washington Gas, use a different variation of the MMF than Washington Gas utilizes for its allocations in its ACOSS

2. <u>Loss of Ratemaking Transparency</u>

Q. SHOULD THIS COMMISSION BE CONCERNED ABOUT THE TRANSPARENCY OF WASHINGTON GAS' APPLICATION?

A. Yes. A major concern of this Commission and the parties to this proceeding should be the substantial loss of ratemaking transparency that underlies the development of the Company's revenue requirements in this proceeding. There are at least four areas in which the transparency of WG's rate presentation in this proceeding must be questioned. Those areas include:

i. WG's expanded Service Company role within the AltaGas corporate structure;

ii. WG's delisting from the SEC;

iii. WG's increased reliance on private placements of long-term debt and;

iv. WG's substantial departure from reliance on FERC accounts when presenting adjustments to its test year costs.

The Commission's evaluation of Washington Gas' revenue increase request in this proceeding must necessarily address the Company's expanded role as a provider of services to a wide array of regulated and non-regulated WGL Holdings and AltaGas U.S. subsidiaries. This Commission is the only entity that can ensure that District ratepayers do not bear costs incurred by Washington Gas in its growing role as a "*service company*."

Washington Gas represents that its determination of revenue requirements for this proceeding starts with the Company's "**per books**" costs, and then the Company allocates those costs among the jurisdictions in which it provides regulated gas services (i.e., the District of Columbia, Maryland, Virginia, and FERC). However, the Supplemental Information provided by the Company with its Application and the Company's Cost Allocation and Inter-company Pricing Manual ("CAM") provide substantial evidence of Washington Gas Light Company's role as a "*service company*" for numerous AltaGas U.S. affiliates (many of which are unregulated entities). The Company's most recent CAM, filed with this Commission by Washington Gas on April 30, 2024, identifies more than 30 affiliated entities (including a significant number of AltaGas affiliates that are outside of the WGL Holdings corporate umbrella) for which Washington Gas Light Company has contracted to provide services.[13] Those categories of services represent a wide range of activities that Washington Gas may be called upon to provide.[14]

[13] The Washington Gas Light Company Cost Allocation and Inter-company Pricing Manual filed by the Company under DCPSC Docket WGCAM2024-01-G on April 30, 2024, page 21.
[14] Ibid., page 24.

Yet, nothing in the Company's development and presentation of its revenue requirements for this proceeding clearly documents any adjustments to Washington Gas Light Company's "per books" costs and revenues to reflect allocations or assignments of costs the Company has incurred to provide services to affiliated entities or reflect payments (i.e., revenues) received from such entities. The implication is that Washington Gas maintains two sets of books: one set that includes affiliate transactions and one set from which the costs of services provided to affiliates have been excluded. However, the supporting detail for the Company's testimony and exhibits in this proceeding include multiple examples of the influence of affiliate services transactions on Washington Gas' purported "per books" costs and its revenue requirement determinations.

The development of WG's revenue requirements and rates in Washington Gas Light Company base rate proceedings has long involved the performance of both jurisdictional cost allocation studies and class cost of service studies. But nothing in those studies provides necessary and appropriate evidence of the costs of services that WG provides to affiliates and the removal of such costs from the "per books" costs that the Company uses to support its claimed costs and revenues for ratemaking purposes. With Washington Gas Light Company's expanded "**service company**" role under AltaGas U.S., greater focus must be placed on the thorough and careful examination of costs associated with WG's "service company" activities and the impacts of such affiliate transactions on WG's revenue increase requests.

AOBA recognizes that this Commission has required audits of WG's application of its "Cost Allocation and Inter-company pricing Manual" ("CAM"), but the fact remains that there is nothing in the record of this proceeding that demonstrates the Company's development of its revenue requirements in this case has fully reflected the allocations and assignments of **test year** **costs** to affiliates that its CAM requires.

3.WG's Service Agreement with SEMCO Energy

Q. WHY SHOULD THE COMMISSION TAKE PARTICULAR NOTE OF THE PROVISIONS OF THE SERVICE AGREEMENT WASHINGTON GAS HAS ENTERED INTO WITH SEMCO ENERGY?

A. Washington Gas' Service Agreement with SEMCO Energy includes provisions not found in WG's service agreements with other affiliates. Of particular importance are provisions that specify that SEMCO Energy executives are given broad oversight of Washington Gas' activities. For example, Washington Gas has agreed to a provision that states:

> *The President of SEMCO Energy* **will provide** ***oversight of the operations, customer, and business service of Washington Gas,*** *including specialized expertise, strategy direction, and* ***oversight of operational areas such as capital improvements, infrastructure replacement projects, operations safety, customer service, and billings****. Executive services will also include the development and implementation of strategic planning efforts to grow the utility business and enhance operational efficiencies.*[15]

[15] Two copies of Service Agreements between Washington Gas and SEMCO Energy are found among the 353 pages of Service Agreements that Washington Gas provided as part of its April 2, 2022,

The same Service Agreement provides that: "*The Vice President, Human Resources, Utilities, SEMCO Energy* ***will provide oversight*** *of human resources and benefits strategy of AltaGas' U.S. utility businesses…*"[16] Further, in the context of this provision, the Commission must appreciate that Washington Gas constitutes the largest component of AltaGas' U.S. utility businesses. Moreover, as of this point in time, Washington Gas represents the only component of AltaGas' U.S. utility business other than SEMCO's much smaller operations.

Q. HAS ANY WITNESS FOR WASHINGTON GAS IN THIS PROCEEDING ATTEMPTED TO JUSTIFY THESE PROVISIONS OF THE SERVICE AGREEMENT BETWEEN SEMCO AND WASHINGTON GAS AND/OR EXPLAIN THE RATIONALE FOR THESE PROVISIONS?

A. No. The direct testimonies filed by witnesses for WG in this proceeding are devoid of discussion of those provisions. Nowhere is there an explanation of the reasons Washington Gas, SEMCO, or their parent companies found oversight of Washington Gas' activities by executives of a smaller affiliate necessary. Likewise, Washington Gas' witnesses in this proceeding have failed to explain why it is appropriate to assess Washington Gas ratepayers for the costs of such oversight activities when Washington Gas maintains its own executive leadership. If there

Supplemental Information Filing in the DCPSC FC 1169 proceeding. The first, found on pages 289-305 of 353 indicates it was entered into on the 18th day of March 2020. The second, found on pages 321-337 of 353, indicates it was entered into by Washington Gas and SEMCO on the 16th day of December 2020. Both documents contain the same language with respect to the oversight that the identified officers of SEMCO Energy will provide for Washington Gas. See Attachment A, Article III., Description of Services provided by the Affiliate [SEMCO Energy], paragraphs A in each of those Service Agreements.

[16] Ibid., Attachment A, Article III, paragraph B.

are shortcomings in Washington Gas' senior management that necessitate the implementation of such oversight provisions, those shortcomings should be explicitly stated. Moreover, Washington Gas, as well as its parent companies, should document and explain those shortcomings and the analyses they have undertaken to determine that SEMCO's oversight of Washington Gas' operations would provide the most cost-effective alternative for addressing identified shortcomings in WG's senior management capabilities.

Q. ARE THERE OTHER UNIQUE ASPECTS OF THE REFERENCED PROVISIONS OF THE SEMCO-WG AFFILIATE SERVICE AGREEMENT?

A. Yes. Those provisions of the Service Agreement between SEMCO and Washington Gas, which delegate **oversight** responsibilities to a party other than a parent company, are not found in any of the other service agreements. Moreover, no other affiliate service agreement provided by the Company **specifies an individual by organization and title** and states that the individual "**will provide**" specific "oversight" or other services. Furthermore, it is unclear whether the identified provisions are intended to apply to anyone who may subsequently hold the specified SEMCO titles or only the current persons who hold the specified positions for SEMCO. It is not inherently obvious why Washington Gas, AltaGas, or this Commission would assume that either the current or future holders of such titles for SEMCO are necessarily better qualified to exercise such oversight for Washington Gas' activities than Washington Gas' own senior management.

When addressing the services Washington Gas is committed to provide under the SEMCO-WG Service Agreements and under other service agreements between Washington Gas and its non-parent company affiliates, the provider of services is typically specified as "**Washington Gas" [not a specific individual within Washington Gas].** Further, such provisions typically state that Washington Gas "***may provide***" a specified service for an affiliate or "***may advise and assist***" the affiliate in a specified activity. Thus, through the use of the word "***may,***" the service agreement language allows the affiliate discretion to determine when such services or advice is necessary or useful. However, regardless of whether oversight by SEMCO executives is discretionary or non-discretionary, it is clear from the content of the SEMCO – Washington Gas Service Agreement that Washington Gas ratepayers have been asked to bear costs for services provided by specific SEMCO executives without any demonstration of shortcomings in the capabilities of Washington Gas' own senior management.

Q. WAS "*OVERSIGHT*" OF WG'S ACTIVITIES BY SEMCO EXECUTIVES ENVISIONED AT THE TIME THE MERGER SETTLEMENT AGREEMENT WAS ENTERED INTO BY THE PARTIES AND APPROVED BY THIS COMMISSION?A. No. As suggested in paragraph 18 of the Merger Settlement Agreement, it was envisioned that Washington Gas's existing management team would "… *manage Washington Gas' business and, as available, provide guidance to AltaGas's other U.S. regulated utility businesses.*"[17] There was no mention at

[17] Order No. 88631, Appendix A, page 10, paragraph 18.

any time in the Merger proceeding of SEMCO executives being given oversight of Washington Gas' business activities. To the contrary, the testimony of witness O'Brien for the Joint Applicants in the Merger Proceeding stated that:

> … AltaGas's belief in maintaining substantial local control of utility operations, summarize the measures that AltaGas has in place for its existing utilities to preserve local control and ensure safe and reliable service, and explain how those measures will be extended to Washington Gas after the Merger is completed.[18]

Q. ARE THE "*OVERSIGHT*" PROVISIONS IN THE WG-SEMCO SERVICE AGREEMENT CONSISTENT WITH THE TERMS OF THE MERGER SETTLEMENT?

A. No. Throughout the merger settlement process, the maintenance of Washington Gas Light Company as a separate financial entity from AltaGas and as an entity insulated from the bankruptcy of affiliates were important concerns. The oversight of Washington Gas' activities by executives of another AltaGas affiliate is not consistent with the maintenance of such a separation, and the service company role now performed by Washington Gas for AltaGas U.S. affiliates erodes the effectiveness of the bankruptcy protections sought through ring-fencing.

[18] Case No. 9449, Direct Testimony of Witness O'Brien, page 2, line 20, to page 3, line 2.

4. <u>WG's Expanded Service Company Role</u>

Q. DOES THE SERVICE COMPANY ROLE NOW PERFORMED BY WASHINGTON GAS COMMINGLE COSTS FOR UTILITY AND NON-UTILITY BUSINESS ACTIVITIES AND NEGATIVELY IMPACT TRANSPARENCY FOR UTILITY RATEMAKING PURPOSES?

A. Yes, most definitely. Among the AltaGas U.S. affiliates for which Washington Gas has executed Service Agreements and has provided services are: (1) multiple power generation businesses in California, including AltaGas Blythe Energy; (2) an array of WGL Midstream business entities; (3) energy marketing businesses including WGL Energy Services, Inc., AltaGas Marketing U.S., and PetroGas, Inc.; and (4) a variety of unregulated renewable and/or sustainable energy businesses.

The services performed by WG for affiliated entities produce a commingling of regulated and non-regulated business activities that greatly complicate cost determinations for WG's regulated utility business. That commingling of costs also impedes the transparency of ratemaking cost determinations. Washington Gas represents that its affiliate transactions are performed in accordance with its CAM and Service Agreements. However, the CAM and service agreements often provide only general guidance and leave considerable room for discretion.

Clearly, such matters add significant complexity to Washington Gas's accounting activities and require WG to engage in extensive additional accounting entries and account reconciliations that would not be required of the Company either on a stand-alone basis or if either AltaGas or AltaGas U.S. provided those services through a "service company" operation outside of Washington Gas.

Q. HAVE THE NON-REGULATED BUSINESS ACTIVITIES THAT RESIDED UNDER WGL HOLDINGS PRIOR TO THE MERGER CLOSE BEEN MOVED TO APPROPRIATE BUSINESS UNITS AND REASONABLY SEGREGATED FROM WASHINGTON GAS LIGHT COMPANY'S UTILITY BUSINESS?

A. No. The number and mix of non-regulated business activities under the WGL Holdings corporate umbrella have changed, but there has been no effort to fully segregate WGL Holdings' non-regulated business activities or move those activities under a separate AltaGas entity. Most of the WGL Holdings' non-regulated business remain heavily dependent on Washington Gas for a wide range of services. Instead, the number of non-regulated affiliated entities to which Washington Gas provides services has been expanded and now includes many affiliated entities not under the WGL Holdings corporate umbrella.

Q. IS THE USE OF A REGULATED UTILITY TO PROVIDE SERVICES TO AN ARRAY OF UNREGULATED AFFILIATED ENTITIES FREQUENTLY FOUND WITHIN THE GAS AND ELECTRIC UTILITY INDUSTRIES?

A. No, it is not. It is far more common for the parent company to maintain a separate "**Service Company**" to provide such services. Service Company arrangements more typically involve the provision of services to subsidiaries of the overall holding company by an entity directly under the parent company. In such structures, the utility is a receiver of services from the "Service Company," and its books are not littered with transactions, costs, and accounting adjustments associated with services that it provided to or received from other affiliated entities.

Q. ARE THE SPECIFIC ELEMENTS OF WG'S AFFILIATE SERVICE COSTS THAT THE COMMISSION SHOULD ADDRESS IN ITS EFFORTS TO RENDER A REVENUE REQUIREMENTS DETERMINATION FOR WASHINGTON GAS IN THIS PROCEEDING?

A. Yes. In the following discussion, two elements of the affiliate service arrangements between Washington Gas and its affiliate, SEMCO Energy, are addressed. Those elements include:

- Costs for Oversight of WG by SEMCO Executives
- WG's Use of SEMCO for Accounts Payable

Q. WHY DO YOU CALL ATTENTION TO THESE CHARGES?

A. Attachment A, Article III. "Description of Services provided by the Affiliate," to the Affiliate Service Agreement between Washington Gas and SEMCO Energy includes rather unique language. It states:

> ***The President of SEMCO Energy will provide oversight** of the **operations, customer and business services of Washington Gas**, including specialized expertise, strategy direction and **oversight of operational areas such as capital improvements, infrastructure replacement projects, operations safety, customer service and billings**. Executive services will also include development and implementation of strategic planning efforts to grow the*

> *utility business and enhance operational efficiencies*.[19] (Emphasis added.)

None of the other Service Agreements that Washington Gas has entered into with affiliates, including its Service Agreement with AltaGas Ltd., includes such a conveyance of responsibilities for Washington Gas' operations to a person not directly employed by Washington Gas. AOBA questions both the need for, and appropriateness of, this broad assignment of responsibility for oversight of Washington Gas' operations to an employee of an affiliate. This arrangement is problematic for two reasons.

First, it is inconsistent with the intent of the Settlement in the Merger proceeding (Formal Case No. 1142) which made as a point of emphasis the need to maintain the separateness of Washington Gas from AltaGas. An arrangement under which the President of SEMCO (i.e., an AltaGas subsidiary) exercises "*oversight*" of the operations of Washington Gas does not maintain the separateness of Washington Gas.

Second, the apparent need for an executive of an affiliate to assume oversight responsibilities for Washington Gas can only convey a lack of confidence on the part of AltaGas in capabilities of Washington Gas' executive management. If there are deficiencies in existing Washington Gas management, those deficiencies should be identified and remedied. Washington Gas ratepayers should not be required to pay for Washington Gas' executive management and also be

[19] FC 1169 Exhibit WG (P)-1, pages 63 and 64 of 71, Washington Gas Light Company and SEMCO Energy Inc. Service Agreement, Attachment A, Article III, Description of Services provide by the Affiliate, Section A, Executive Services for Utility Operations.

required to pay for the perceived shortcomings of the existing executive management in the form of added costs for outside executive oversight.

Q. HAS THIS COMMISSION EVER SPECIFICALLY ACCEPTED OR APPROVED THE TERMS OF THE SERVICE AGREEMENT BETWEEN WASHINGTON GAS AND SEMCO ENERGY?

A. It does not appear that this Commission has ever specifically accepted or rejected the terms of the Service Agreement between Washington Gas and SEMCO Energy.

Q. HOW SHOULD COSTS BILLED TO WASHINGTON GAS FOR THE SERVICES PROVIDED BY THE PRESIDENT OF SEMCO AND/OR THE SEMCO ENERGY VICE PRESIDENT, HUMAN RESOURCES, BE TREATED FOR RATEMAKING PURPOSES IN THIS PROCEEDING?

A. I will respond to this question in two parts.

First, in the absence of compelling evidence regarding deficiencies in Washington Gas' directly employed executive management team, District of Columbia ratepayers must not be held responsible for redundant management costs resulting from the involvement of SEMCO's oversight of WG's operations and/or the involvement of other SEMCO Energy executives in the provision of oversight for WG's operations. If AltaGas believes that the oversight by SEMCO executives is advantageous for its purposes, even though WG has substantial senior management already in place, then any costs for additional oversight of

WG's operations by the SEMCO President should be borne directly by AltaGas. If AltaGas found the oversight of the SEMCO executives necessary due to documented shortcomings or deficiencies in WG's directly employed executive management, test year charges for the SEMCO President's time and expenses may be justifiable. However, the compensation provided to WG's executive management should be adjusted downward as a reflection of the identified shortcomings or deficiencies.[20]

Q. DOESN'T WASHINGTON GAS RETAIN THE PEROGATIVE TO EMPLOY WHAT EVER SERVICES IT DEEMS NECESSARY TO MANAGE ITS OPERATIONS AND OVERSEE ITS ACTIVITIES?

A. In general, utilities are provided broad discretion with respect to the persons they employ and the qualifications of such individuals. However, given the provisions of the Merger Settlement regarding maintenance of Washington Gas as a separate entity from AltaGas and those relating to maintenance of local control of Washington Gas' operations,[21] such actions as the assignment of oversight responsibilities for Washington Gas' operations to the President of SEMCO (where SEMCO is a direct subsidiary of AltaGas and AltaGas US) must be viewed as being in violation of both of those important aspects of the Merger Settlement.

[20] As no shortcomings or deficiencies in WG's executive management have been identified to date by AltaGas or its representatives, this Commission must conclude that the test year charges for service provided by the SEMCO President reflect unnecessary redundant costs incurred solely for the benefit of AltaGas Ltd.

[21] Formal Case No. 1142, Order No. 19396, June 29, 2018: ¶37.LL and ¶37.LLL; Appendix A, ¶18, ¶18a and ¶25.

Q. DID WASHINGTON GAS RELY ON SEMCO ENERGY FOR THE PROVISION OF ACCOUNTS PAYABLE SERVICES DURING THE TEST YEAR?

A. I find no evidence that SEMCO provided Accounts Payable services for Washington Gas during the test year.

Q. WHY IS THE COMPANY'S USE OF SEMCO FOR THE PROVISION OF SUCH SERVICE RELEVANT TO THE COMMISSION REVENUE REQUIREMENTS DETERMINATIONS IN THIS CASE?

A. Transitions in AltaGas' corporate organization should be expected to impact WG's costs for the rate effective period. However, the Company offers no testimony regarding that change or the manner in which it is expected to impact the Company's costs for the rate effective period. Washington Gas has offered adjustments for other elements of its costs for which it claims adjustments are necessary for the rate effective period, but it does not address apparently known changes.

Generally, it would be assumed that Washington Gas would not engage in this change in the provision of Accounts Payable services if it did not result in cost savings. Yet, the Company has offered no information regarding either such anticipated savings or the costs for the change in the provider of Accounts Payable services for the Company. The Commission should also recognize that these outsourced services that are being transitioned to SEMCO Energy are an element of the overall Non-Labor Costs for which the Company seeks approval of an inflation cost adjustment. Thus, under the Company's rate proposals in this proceeding, the costs associated with WG's test year provider of outsourced Accounts Payable functions (i.e., Accenture) will be inflated for ratemaking purposes. Yet, WG's representations on this matter provide reason to expect that the Company's costs for those services may actually be reduced.

Q. HAS WASHINGTON GAS DEMONSTRATED THAT IT CANNOT MORE COST EFFECTIVELY OBTAIN THE ACCOUNTS PAYABLE SERVICES FOR ITS UTILITY OPERATIONS EITHER IN-HOUSE OR THROUGH A COMPETITIVE SERVICE PROVIDER?

A. No, it has not. In Order No. 21420 this Commission explicitly required Washington Gas to "*explain the reasons that service obtained from an affiliate could not be obtained more cost-effectively either in-house or through a competitive service provider.*"[22] Despite this directive, the Company's Supplement Direct testimony filed on November 4, 2024 provides no justification for the election by WG (and/or its parent companies) to use SEMCO Energy as its provider of Accounts Payable services. Thus, the record lacks any showing that Washington Gas could not obtain those services "*more cost-effectively either in-house or through a competitive service provider.*" Although the transition of the provision of WG's Accounts Payable services to SEMCO Energy reportedly did not commence until May 2022, that arrangement will impact the Company's costs in the rate effective period and therefore are relevant to the Commission's rate considerations in this case.

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[22] Order No. 21420, paragraph 29, page 12.

Q. DO YOU OFFER ANY FURTHER RECOMMENDATIONS REGARDING WG'S CURRENT ROLE AS A PROVIDER OF SERVICES TO A NUMBER OF ALTAGAS U.S. AND WGL HOLDINGS AFFILIATES?

A. Yes. The Commission should direct Washington Gas to immediately start the process of terminating its "Service Company" role for affiliates. Further, the Company should be required to complete the termination of such activities within six months of a final order in this proceeding.

If WG is allowed to continue its current Service Company role, annual audits of the Company's books for regulatory purposes beyond which were scoped after Order No. 21939 will be necessary, and the costs of those audits should be borne fully by WG's shareholder, AltaGas. Since the use of Washington Gas to provide a service company role within AltaGas/ASUS/WGL Holdings is elective on the part of AltaGas, such activities by Washington Gas, a regulated utility, should be viewed as primarily for the benefit of AltaGas and its other affiliates. The Company has provided no evidence that its service company role produces net benefits for its District of Columbia ratepayers.

Regulating a gas utility's operations is a detailed and complex process. The added complexity of sorting out accounting entries and costs associated with a wide array of affiliate transactions impedes the transparency of Washington Gas' operations and costs, as well as necessary regulatory oversight of the Company's utility operations.

2. Affiliate Service Recommendations

Q. HOW SHOULD THIS COMMISSION ADDRESS WASHINGTON GAS' AFFILIATE TRANSACTIONS?

A. First, the Commission should find that WG's affiliate transactions negatively impact the transparency of the Company's rate-making cost determinations in this proceeding. Second, the Commission should direct Washington Gas and AltaGas to terminate Washington Gas' service company role for both WGL Holdings affiliates and AltaGas U.S. affiliates within six months of the conclusion of this proceeding. Third, the Commission should immediately terminate the provisions of WG's Service Agreement with SEMCO, which convey oversight responsibilities for any or all elements of Washington Gas operations, customer and business services. Fourth, the Commission should find that the Company has failed to justify the costs SEMCO Energy has allocated to Washington Gas for executive services. I also note that the elimination of WG's service company role could significantly reduce the number of documents in each case that must be classified as confidential.

C. AOBA'S RECOMMENDED REVENUE REQUIREMENT

Q. WHAT IS THE REVENUE INCREASE WASHINGTON GAS IS REQUESTING IN THIS PROCEEDING?

A. Washington Gas Presents its revenue increase request in Exhibit (A) the Direct Testimony of Witness Steffes. He indicates that Washington Gas is requesting $45.6 million, including $11.7 million related to PROJECTpipes.

Q. HAVE YOU QUANTIFIED THE REVENUE REQUIREMENT IMPACT OF YOUR RATE OF RETURN AND CAPITAL STRUCTURE RECOMMENDATIONS?

A. Yes, AOBA Exhibit (A)-3 illustrates the impact of AOBA's recommended return on equity and capital structure which produces a reduction to the Company's requested revenue requirement by $6.9 million.

Q. WHAT OTHER ADJUSTMENTS TO THE COMPANY'S REVENUE REQUIREMENT DOES AOBA PROPOSE AT THIS TIME?

A. Special Contract customers earn below the system average rate of return as discussed in the Testimony of AOBA Witness B. Oliver. The difference between the rate of return for the Special Contract customers and the system average rate of return should be borne by the Company and not District ratepayers. The difference in rates of return results in a reduction of the Company's requested revenue requirement of approximately $3.8 million.

Q. WHAT IS AOBA'S RECOMMENDED REVENUE REQUIREMENT IN THIS PROCEEDING

A. At the time of filing its Direct Testimony AOBA has Identified approximately $10.7 million in reductions to the Company's requested revenue requirement. This results in AOBA's proposed revenue requirement of not greater than $34.9. million.

Q. DOES YOUR RECOMMENDED REVENUE REQUIREMENT PRESENTED HEREIN REPRESENT AOBA'S FINAL POSITION?

A. No. AOBA's recommended revenue requirements are solely a reflection of the adjustments to Washington Gas' proposals that AOBA presents in this proceeding. Furthermore, AOBA reserves the right to support revenue requirement positions developed by OPC, DC Government, and other intervenors, as well as the inclusion of additional revenue requirement issues that may be developed as this proceeding progresses.

Q. DO YOU OFFER ANY CONCLUDING OBSERVATIONS?

A. I do. Extensive problems in the data, assumptions, and methods that Washington Gas has employed to develop its requested revenue requirement in this proceeding severely undermine this Commission's ability to find that the Company has reasonably and properly justified any revenue increase at this time. This Commission is well aware of its responsibility to ensure that rates approved for utility services in the District are just and reasonable. On the basis of the testimony and analyses that Washington Gas has provided in its Direct and Supplemental

Direct Testimony, such a determination is not possible. Many of the recommendations presented herein are premised on efforts to correct limited elements of the Company's filing. However, an objective assessment of the details of WG's presentation can only conclude that the shortcomings and errors in the Company's presentation are too substantial to justify approval of any rate increase at this time

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF	)	
	)	
The Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Gas Service	)))	**Formal Case No. 1180**

DECLARATION

I, Timothy B. Oliver, do hereby declare under the penalty of perjury that I am authorized to make this Declaration on behalf of the Apartment and Office Building Association of Metropolitan Washington; that the foregoing testimony and exhibits were prepared by me or under my direction and supervision; and that the contents herein are true and correct to the best of my knowledge, information and belief.

Timothy B. Oliver
January 24, 2025

Washington Gas Light Company

DC PSC FC 1180

Cost of Equity Analysis

Ln No	Analytic Model	Average Dividend Yield	Dividend Growth Component	Adjusted Dividend Yield	Earnings Growth Rate	Indicated Rate of Return
	DCF Cost of Equity					
	Washington Gas Proxy Group					
1	Zacks	3.93%	0.11%	4.04%	5.79%	9.84%
2	Seeking Alpha	3.93%	0.11%	4.04%	5.78%	9.82%
3	Finviz	3.93%	0.11%	4.04%	5.74%	9.78%
						9.81%
						Current Treasury Rate
	CAPM Analysis *(Zacks Betas)*					
8	@ 7.00% Adjusted Risk Premium					9.34%
9	@ 8.00% Adjusted Risk Premium					9.97%
	CAPM Analysis *(Seeking Alpha Betas)*					
10	@ 7.00% Adjusted Risk Premium					8.12%
11	@ 8.00% Adjusted Risk Premium					8.57%
	CAPM Analysis *(Finviz Betas)*					
12	@ 7.00% Adjusted Risk Premium					9.35%
13	@ 8.00% Adjusted Risk Premium					9.99%
14	**Average of CAPM Results**					**9.22%**
15	**Average of DCF and CAPM**					**9.52%**
16	**AOBA Recommendation**					**9.50%**

Washington Gas Light Company
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Dividend Yields & Earnings Growth Data for Proxy Group Companies

Ln No	Proxy Group Company	Ticker Symbol	Market Price Per Share 1/ High	Low	Average	Indicated Dividend Per Share 1/	Dividend Yield	Projected 5-Year Earnings Growth Zacks 2/	Seeking Alpha 3/	Finviz 4/
1	**Atmos Energy Corp.**	**ATO**	$ 152.65	$ 110.46	$ 131.56	$ 3.48	2.65%	7.01%	7.51%	7.51%
2	New Jersey Rescources Corp	**NJR**	$ 51.95	$ 39.44	$ 45.70	$ 1.80	3.94%	NA	5.60%	5.00%
3	NiSource Inc.	**NI**	$ 38.56	$ 24.80	$ 31.68	$ 1.06	3.35%	7.45%	7.78%	7.95%
4	Northwest Natural Gas Co.	**NWN**	$ 44.25	$ 34.82	$ 39.54	$ 1.96	4.96%	NA	4.83%	5.00%
5	ONE Gas, Inc.	**OGS**	$ 78.89	$ 57.74	$ 68.32	$ 2.64	3.86%	2.89%	2.45%	2.45%
6	Spire Inc.	**SR**	$ 73.64	$ 56.36	$ 65.00	$ 3.14	4.83%	5.82%	6.50%	6.50%
7	**Mean**		**$ 73.32**	**$ 53.94**	**$ 63.63**	**$ 2.35**	**3.93%**	**5.79%**	**5.78%**	**5.74%**

1/ From www.Zacks.com 1-7-2023
2/ From www.Zacks.com 1-7-2025
3/ From www.seekingalph.com 1-7-2025
4/ From www.finviz.com 1-7-2025

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Capital Asset Pricing Model (CAPM) Cost of Equity Estimates
Zacks Betas

Ln No	Proxy Group Company	Ticker Symbol	Zacks Betas 1/	Risk Premium 7.00%	Risk-Free Rate 2/ 4.92%	Zacks Betas 1/	Risk Premium 8.00%	Risk-Free Rate 2/ 4.92%
1	Atmos Energy Corp.	**ATO**	0.71	4.97%	9.89%	0.71	5.68%	10.60%
2	New Jersey Rescources Corp	**NJR**	0.64	4.48%	9.40%	0.64	5.12%	10.04%
3	Nisource	NI	0.54	3.78%	8.70%	0.54	4.32%	9.24%
4	Northwest Natural Gas Co.	**NWN**	0.62	4.34%	9.26%	0.62	4.96%	9.88%
5	ONE Gas, Inc.	**OGS**	0.71	4.97%	9.89%	0.71	5.68%	10.60%
6	Spire Inc.	**SR**	0.57	3.99%	8.91%	0.57	4.56%	9.48%
7	**Mean**		**0.632**	**4.42%**	**9.34%**	**0.632**	**5.05%**	**9.97%**

1/ From www.Zacks.com 1-7-2025
2/ From www.treasury.gov 1-9-2025

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Capital Asset Pricing Model (CAPM) Cost of Equity Estimates
Seeking Alpha Betas

Ln No	Proxy Group Company	Ticker Symbol	Seeking Alpha Betas 1/	Risk Premium 7.00%	Risk-Free Rate 2/ 4.92%	Seeking Alpha Betas 1/	Risk Premium 8.00%	Risk-Free Rate 2/ 4.92%
1	Atmos Energy Corp.	**ATO**	0.40	2.80%	7.72%	0.40	3.20%	8.12%
2	New Jersey Rescources Corp	**NJR**	0.43	3.01%	7.93%	0.43	3.44%	8.36%
3	Nisource	NI	0.34	2.38%	7.30%	0.34	2.72%	7.64%
4	Northwest Natural Gas Co.	**NWN**	0.58	4.06%	8.98%	0.58	4.64%	9.56%
5	ONE Gas, Inc.	**OGS**	0.51	3.57%	8.49%	0.51	4.08%	9.00%
6	Spire Inc.	**SR**	0.48	3.36%	8.28%	0.48	3.84%	8.76%
7	**Mean**		**0.457**	**3.20%**	**8.12%**	**0.457**	**3.65%**	**8.57%**

1/ From www.seekingalph.com 1-7-2025
2/ From www.treasury.gov 1-9-2025

Washington Gas Light Company
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Capital Asset Pricing Model (CAPM) Cost of Equity Estimates
Finviz Betas

Ln No	Proxy Group Company	Ticker Symbol	Value Line Betas 3/	Risk Premium 7.00%	Risk-Free Rate 2/ 4.92%	Value Line Betas 3/	Risk Premium 8.00%	Risk-Free Rate 2/ 4.92%
1	Atmos Energy Corp.	**ATO**	0.71	4.97%	9.89%	0.71	5.68%	10.60%
2	New Jersey Resources Corp	**NJR**	0.65	4.55%	9.47%	0.65	5.20%	10.12%
3	NiSource	**NI**	0.54	3.78%	8.70%	0.54	4.32%	9.24%
4	Northwest Natural Gas Co.	**NWN**	0.61	4.27%	9.19%	0.61	4.88%	9.80%
5	ONE Gas, Inc.	**OGS**	0.70	4.90%	9.82%	0.70	5.60%	10.52%
6	Spire Inc.	**SR**	0.59	4.13%	9.05%	0.59	4.72%	9.64%
7	**Mean**		**0.633**	**4.43%**	**9.35%**	**0.633**	**5.07%**	**9.99%**

1/ From www.finviz.com 1-7-2025
2/ From www.treasury.gov 1-9-2025

Washington Gas Light Company

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Comparative Capital Structure Analysis of AltaGas
With and Without Washington Gas

		AltaGas 1/	Washington Gas 2/	AltaGas w/o WG
1	Total Debt	$ 10,136	$ 2,122	$ 8,014
2	Total Equity	$ 8,263	$ 2,344	$ 5,919
3	Total Capitalization	$ 18,399	$ 4,466	$ 13,933
4	Total Debt	55.1%	47.5%	57.5%
5	Total Equity	44.9%	52.5%	42.5%
6	Total Capitalization	100.0%	100.0%	100.0%

1/ Attachment B-AltaGas Q3 Financial Report, Pages 48 and 69.
2/ Washington Gas Exhibit (B)-1.
Note: dollars in thousands

Washington Gas Light Company

DC PSC FC 1180

AOBA Recommended Overall Cost of Capital

Based on AOBA Recommended Capital Structure and Cost of Equity

		Capitalization	Ratio	Cost	Required Return	Revenue Impact Calculation
1	Total-Debt	$ 2,344	50.00%	4.97% 1/	2.485%	
2	Common Equity	$ 2,344	50.00%	**9.50%** 2/	4.75%	
3	Total	$ 4,688	100.00%		**7.24%**	
4	WGL Requested ROR				7.87%	
5	AOBA Recommended Reduction in WGL ROR				-0.64%	
6	DC Unadjusted Rate Base					$ 760,993
7	Change in Required Return					$ (4,863)
8	Tax Gross-Up Factor					72.4820%
9	Change in Revenue Requirement					$ (6,709)
10	Uncollectibles Allowance 3/		2.7046%			$ (181.45)
11	**Revenue Requirement Adjustment**					**$ (6,890.35)**

1/ Exhibit WG (B)-1, page 1 of 1.
2/ Exhibit AOBA (B)-1, page 1, line 16.
3/ Exhibit WG (D)-2, page 3 of 3.
4/ Exhibit WG (D)-2, page 3 of 3.

Washington Gas Light Company

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Calculation of Revenue Requirement Associated with Special Contracts Earnings Deficiency

1	Special Contract Rate Base 1/		$ 47,331,405
2	Requested ROR 2/		0.0787
3	Required Return on Special Contract Service		3,724,982
4	CCOSS ROR for Special Contracts 1/		0.0217
5	Actual Return from Special Contract Service		$ 1,027,091
6	Special Contracts Return Deficiency		2,697,890
7	Tax Factor 3/		72.483%
8	Tax Adjusted Return Deficiency		$ 3,722,100
9	Uncollectibles Allowance 3/	**2.7046%**	$ 100,668
10	Special Contract Revenue Rquirement Deficiency		**$ 3,822,768**

1/ WG Exhibit (F)-4, page 1.
2/ WG Exhibit (B)-1
3/ Exhibit WG (D)-2, page 3 of 3.

Washington Gas Light Company
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AOBA's Revenue Requirement Recommendations

1	Revenue Increase Request 1/	$ 45,600,000
2	Special Contract Revenue Defficiency 2/	$ (3,822,768)
3	Rate of Return and Capital Structure Adjustment 3/	$ (6,890,349)
4	AOBA Recommended Revenue Requirement 4/	$ 34,886,882

1/ WG Exhibit (A), page 2.
2/ AOBA Exhibit (A)-4, line 10.
3/ AOBA Exhibit (A)-3. line 9.
4/ This revenue requirement represents AOBA's recommendations related to issues discussed in AOBA's direct testimony. AOBA may choose to adopt or support additional adjustments to Washington Gas' proposed revenue requirement developed by other intervenors.

Attachment A
Resume of Timothy Oliver
Formal Case No. 1180

TIMOTHY B. OLIVER

Revilo Hill Associates, Inc.
7103 Laketree Dr.
Fairfax Station, VA 22039
(757) 810-9609
e-mail: ***timoliver@revilohill.com***

PROFESSIONAL EMPLOYMENT

07/19 - Current **Vice President and Senior Consultant**, Revilo Hill Associates, Inc.

- Provides testimony on revenue requirements, costs of capital, class cost of service, rate design, and regulatory policy issues in utility proceedings.
- Evaluates to the merits of proposed utility mergers and acquisitions. Critically assesses the proposed transactions, develops merger settlement positions, presents testimony in utility regulatory proceedings, and evaluates settlement proposals for highly complex mergers between large utility holding companies: including examination of the impacts on the economies of the affected regulatory jurisdictions, the influences on regulatory practices and policies, and the effects of that merger on consumers.
- Participates in technical conferences, working groups, stakeholder meeting, and other similar forums as a subject matter expert in the areas of energy technology, energy efficiency, greenhouse gas emissions reductions, and alternative forms of regulation.

01/12 - 07/19 **Senior Consultant**, Revilo Hill Associates, Inc.

- Performed cost of equity and overall rate of return analyses for numerous gas and electric utility regulatory proceedings.
- Evaluated of the merits of a utility proposal for system wide deployment of Advanced Metering Infrastructure (AMI) including the costs and benefits of the utility proposal and the ratemaking implications of the utility's proposed accounting treatment of its AMI program costs.
- Reviewed in detail utility class cost allocation studies and prepared and presented recommendations for the use of alternative allocation methods with supporting analyses and rationales.
- Examined a utility proposals for natural gas distribution system expansion, the rate and customer impacts of those proposals.

01/08 - 01/12 **Project Manager**, Revilo Hill Associates, Inc.

- Conducted a series of case studies that evaluated the energy efficiency of multi-family apartment buildings of varying age and design in the District of Columbia.
- Reviewed and analyzed annual Distribution Adjustment Charge and Gas Cost Recovery filings submitted by a New England natural gas distribution utility.
- Evaluated proposals for LED Street Lighting programs and related tariff issues.
- Developed issues associated with proposals for the implementation of revenue decoupling for gas and electric utility operations.
- Assessed Net Metering Pilot Program and evaluated proposals for Net Metering tariff changes.
- Designed a program to encourage improved energy efficiency in commercial office buildings and multi-family rental housing in the Washington, DC metropolitan area, and supported the creation of an Energy Managers' Roundtable to provide building energy managers a forum in which to share their experience with respect to energy-efficiency technologies, vendor performance, and best practices.
- Examined the factors contributing to a sharp increase in winter petroleum product prices for consumers in a New England state.
- Participated in an analysis of the impacts of a proposed Liquefied Natural Gas (LNG) terminal facility on energy markets in New England.
- Planned and conducted a focus group comprised of Energy Managers to assess (1) their understandings of energy efficiency issues, (2) needs for information and assistance in the identification of energy efficiency opportunities, and (3) other obstacles to their employment of more energy efficient systems and technologies.

05/06 - 01/08 **Research Associate**, Revilo Hill Associates, Inc.
Assisted in the evaluation of energy pricing alternatives for commercial and institutional electricity and natural gas customers; created a data base to support the marketing of competitive energy services for a major broker/aggregator; provided analytic support for expert testimony in natural gas and electric utility regulatory proceedings in seven different jurisdictions.

10/06- 4/07 **Market Research Team**, Vail Resorts, Vail, CO
Conducted on-mountain and in-town market research for customer satisfaction, brand marketing, and demographics for analysis.

06/03 - 05/06 **Research Analyst**, Revilo Hill Associates, Inc.
Developed a large-scale electronic spreadsheet model of competitive electricity supply costs for one of the nations largest commercial customer based energy aggregations; and assisted in an investigation fuel oil price increases through the analysis of detailed monthly supply, demand, and pricing data for major oil terminal operators within a New England state.

05/02- 8/03 **Research Assistant**, College of William and Mary, Chemistry Department
Preformed extensive mathematical and computer modeling analysis of experimental data to determine the proton affinities of non-protein amino acids and their derivatives; maintained and repaired laboratory equipment including a quadrapole ion trap mass spectrometer.

EDUCATION

2018 MS program, Global Energy Management, University of Colorado at Denver
2009 Building for the Future: Sustainable Home Design, Solar Energy International, Carbondale, CO
2008 Certified Energy Manager, Association of Energy Engineers
2005 BS in Chemistry, College of William and Mary, Williamsburg, VA

RATE CASE PARTICIPATION

SUBMITTED TESTIMONY:

2024	DC	Potomac Electric – Base Rates	Case No. 1176
2024	MD	Potomac Electric – Base Rates	Case No. 9702
2023	MD	Washington Gas- Base Rates	Case No. 9704
2023	VA	Dominion Energy Biennial Review	Docket No. PUR-2023-00101
2023	VA	Washington Gas – Base Rates	Docket No. PUR-2022-00054
2023	DC	Washington Gas – Base Rates	Formal Case No. 1169
2022	UT	Dominion Energy Utah-Base Rates	Docket No. 22-057-03
2021	MD	Potomac Electric – Base Rates	Case No. 9655
2020	MD	Washington Gas Light Company	Case No. 9651
2020	DC	Washington Gas – Base Rates	Formal Case No. 1162
2019	DC	Potomac Electric – Base Rates	Formal Case No. 1156
2019	DC	Potomac Electric – Base Rates	Formal Case No. 1150
2019	VA	Washington Gas – Base Rates	Docket No. PUR-2018-0042
2019	MD	Washington Gas – Base Rates	Case No. 9605
2019	MD	Potomac Electric – Base Rates	Case No. 9602
2018	MD	Washington Gas – Base Rates	Case No. 9481
2017	DC	AltaGas – WGL Merger	Formal Case No. 1142
2017	MD	AltaGas – WGL Merger	Case No. 9449
2017	MD	Potomac Electric – Base Rates	Case No. 9443
2017	VA	Washington Gas – Base Rates	Docket No. PUE-2016-00001
2016	DC	Potomac Electric – Base Rates	Formal Case No. 1139
2016	DC	Washington Gas – Base Rates	Formal Case No. 1137

2016	RI	National Grid – GCR	Docket No. 4643
2016	MD	Potomac Electric - Base Rates	Case No. 9418
2014	MD	Potomac Electric – Base Rates	Case No. 9336
2014	MD	Washington Gas - Base Rate	Case No. 9335
2013	DC	Potomac Electric Power Company	Formal Case No. 1103

OTHER RATE CASE PARTICIPATION:

District of Columbia

Washington Gas Light Company	Formal Case No. 1154
Potomac Electric Power Company	Formal Case No. 1151
Potomac Electric Power Company	Formal Case No. 1150
AltaGas – WGL Merger	Formal Case No. 1142
Potomac Electric Power Company	Formal Case No. 1139
Washington Gas Light Company	Formal Case No. 1137
Potomac Electric Power Company	Formal Case No. 1130
Exelon-PHI Merger	Formal Case No. 1119
Potomac Electric Power Company	Formal Case No. 1116
Washington Gas Light Company	Formal Case No. 1115
Washington Gas Light Company	Formal Case No. 1093
Potomac Electric Power Company	Formal Case No. 1087
Washington Gas Light Company	Formal Case No. 1079
Potomac Electric Power Company	Formal Case No. 1076

Guam

Guam Power Authority	Docket No. 11-090, Ph II
Guam Power Authority	Docket No. 11-090
Guam Power Authority	Docket No. 07-010

Maryland

AltaGas – WGL Merger	Case No. 9449
Potomac Electric Power Company	Case No. 9443
Washington Gas Light Company	Case No. 9433
Exelon-PHI Merger	Case No. 9361
Washington Gas Light Company	Case No. 9322
Potomac Electric Power Company	Case No. 9311
Potomac Electric Power Company	Case No. 9286
Washington Gas Light Company	Case No. 9267
Potomac Electric Power Company	Case No. 9217

Massachusetts

Investigation of Rate Structures to Promote Efficient Deployment of Demand Management	Docket No. 07-50

Rhode Island – Public Utilities Commission

National Grid – Gas GCR	Docket No. 4719
National Grid – Gas DAC	Docket No. 4708

National Grid – Gas GCR	Docket No. 4647
National Grid – Gas Long-Range Plan	Docket No. 4608
National Grid – Gas GCR	Docket No. 4576
National Grid – Gas DAC	Docket No. 4573
National Grid – Gas GCR	Docket No. 4520
National Grid – Gas DAC	Docket No. 4514
National Grid – Gas GCR	Docket No. 4346
National Grid – Gas DAC	Docket No. 4339
National Grid – Gas On-System Margins	Docket No. 4333
National Grid – Gas Base Rates	Docket No. 4323
National Grid – Gas GCR	Docket No. 4283
National Grid – Gas DAC	Docket No. 4269
National Grid – Electric Backup Service	Docket No. 4232
National Grid – Elec & Gas Revenue Decoupling	Docket No. 4206
National Grid – Gas GCR	Docket No. 4199
National Grid – Gas DAC	Docket No. 4196
National Grid – Gas GCR	Docket No. 4097
National Grid – Gas DAC	Docket No. 4077
National Grid – Electric	Docket No. 4065
National Grid – Gas Portfolio Management	Docket No. 4038
National Grid – Gas GCR	Docket No. 3982
National Grid – Gas DAC	Docket No. 3977
National Grid – Gas GCR	Docket No. 3961

Utah

Dominion Energy Utah-Base Rates	Docket No. PUE 2015-00027

Virgin Islands

Water and Power Authority – Water Rates	Docket No. 613
Water and Power Authority – Electric Rates	Docket No. 612
Water and Power Authority – Water Rates	Docket No. 576
Water and Power Authority – Electric Rates	Docket No. 575

Virginia

Virginia Electric Power Company	Docket No. PUE 2015-00027
Virginia Electric Power Company	Docket No. PUE 2011-00027
Washington Gas Light Company	Docket No. PUE 2010-00139

Attachment B
AltaGas Q3 2024 Financial Report
Formal Case No. 1180

ALTAGAS REPORTS STRONG THIRD QUARTER 2024 RESULTS

The Company Expects 2024 Normalized EBITDA to be in the Upper End of Guidance Range, Based on Strong Utilities and Midstream Performance

Calgary, Alberta (October 31, 2024)

AltaGas Ltd. ("AltaGas" or the "Company") (TSX: ALA) reported third quarter 2024 financial results and provided an update on its operations and other corporate developments.

HIGHLIGHTS

(all financial figures are unaudited and in Canadian dollars unless otherwise noted)

- Normalized EPS[1] was $0.14 in the third quarter of 2024 compared to $0.08 in the third quarter of 2023, while GAAP EPS[2] was $0.03 in the third quarter of 2024 compared to a loss of $0.18 in the third quarter of 2023. Year-over-year normalized EPS growth was primarily driven by strong Utilities performance.
- Normalized EBITDA[1] was $294 million in the third quarter of 2024 compared to $252 million in the third quarter of 2023, while income before income taxes was $20 million in the third quarter of 2024 compared to a loss before income taxes of $51 million in the third quarter of 2023. The 17 percent year-over-year growth in normalized EBITDA was principally driven by strong Utilities performance, as outlined below.
- Normalized FFO per share[1] was $0.35 in the third quarter of 2024 compared to $0.50 in the third quarter of 2023, while cash from operations per share[3] was $0.07 in the third quarter of 2024 compared to $0.01 in the third quarter of 2023.
- The Utilities segment reported normalized EBITDA of $117 million in the third quarter of 2024 compared to $71 million in the third quarter of 2023, while income before taxes was $24 million in the third quarter of 2024 compared to a loss of $16 million in the third quarter of 2023. Strong year-over-year growth was principally driven by the partial settlement of Washington Gas' post-retirement benefit pension plan, contributions from rate base and accelerated replacement programs ("ARP") investment, and enhanced cost controls.
- The Midstream segment reported normalized EBITDA of $181 million in the third quarter of 2024 compared to $185 million in the third quarter of 2023, while income before taxes was $123 million in the third quarter of 2024 compared to $61 million in the third quarter of 2023. Despite rail outages due to the Alberta wildfires and national rail strike that drove higher one-time operating costs, AltaGas was able to deliver strong financial performance due to operational execution.
- AltaGas exported a record of 128,272 Bbl/d of liquified petroleum gases (“LPGs") to Asia in the quarter, a nine percent year-over-year increase. Strong export volumes and contributions from the Pipestone assets were offset by lower export margins (including the impact of higher percentage of tolling contracts), higher long-term incentive costs due to AltaGas' rising share price, and a lower year-over-year contribution from the Mountain Valley Pipeline ("MVP") as the asset was placed into service with equity earnings below the Allowance for Funds Used During Construction ("AFUDC") in the third quarter of 2023.
- AltaGas continued to advance key Midstream commercial priorities during and subsequent to the quarter, including:
  - Entering two agreements that have a high-single digit average contract length with a large investment grade international energy company in Northeastern B.C. ("NEBC") for a total of 100 Mmcf/d of gas processing capacity at the Townsend facility, along with associated liquids handling and fractionation services;

(1) Non-GAAP measure; see discussion and reconciliation to US GAAP financial measures in the advisories of this news release or in AltaGas' Management's Discussion and Analysis (MD&A) as at and for the period ended September 30, 2024, which is available on www.sedarplus.ca. (2) GAAP EPS is equivalent to Net income applicable to common shares divided by shares outstanding. (3) GAAP FFO per share is equivalent to cash from operations divided by shares outstanding.

- Extending the contract term with a large Canadian investment grade producer at the Pipestone I gas processing facility in the Alberta Montney for an additional five years, including gas processing, liquids handling and marketing services; and
- Advancing long-term tolling arrangements across the global exports platform with a number of agreements now in definitive documentation stages. This includes AltaGas having contracts in hand or being in active negotiations for more than 100 percent of first phase capacity for the Ridley Island Energy Export Facility ("REEF"). AltaGas continues to target having 60 percent of its export volumes under long-term tolling agreements by the start of the 2027 NGL year.

- The ongoing commercial success reiterates the strategic advantages of AltaGas' assets across NEBC, the Alberta Montney, and the global exports value chain. The Company continues to look forward to leveraging its assets to connect upstream and downstream customers and markets and drive the best collective outcomes for all stakeholders.
- AltaGas remained active from a regulatory perspective during the third quarter, including filing a rate case and proposed accelerated replacement program ("ARP") extension in the District of Columbia ("D.C."). The District Strategic Accelerated Facility Enhancement ("District SAFE") is Washington Gas' third modernization program in D.C. and is focused on long-term safety and reliability.
- AltaGas continued to advance key Midstream growth projects during the third quarter. Strong progress was made on REEF's in-water piling work for the jetty and the site's overburden activities, while compression, refrigeration and vessel fabrication work is advancing in controlled operating environments at offsite manufacturing facilities. At Pipestone II, construction is progressing to plan, including completion of the two acid gas injection wells and the majority of the gas gathering system, while compression, processing and fabrication work is progressing at offsite manufacturing facilities. Both midstream growth projects remain on schedule and on budget with 50 percent of REEF and 92 percent of Pipestone II project costs either incurred or under fixed price contracts.
- MVP in the Appalachian Basin moved into full commercial operations in the quarter with 20-year firm service contracts with investment grade counterparties coming into effect July 1, 2024. The 2.0 Bcf/d pipeline is fully subscribed and is expandable by an additional 475 MMcf/d through low cost compression with extension into North Carolina through the Southgate project. AltaGas' 10 percent, non-operated equity stake in the pipeline remains non-core and is a divestiture candidate for the coming period.
- AltaGas had two financings in the third quarter of 2024, including:
  - On July 9, 2024, AltaGas issued $250 million of senior unsecured medium-term notes with a 5.60 percent coupon, due on March 14, 2054. The net proceeds were used to pay down amounts drawn on the syndicated credit facility, which was incurred when the Company repaid its term loan on June 28, 2024.
  - On September 23, 2024, AltaGas issued US$900 million of 7.20 percent Fixed-to-Fixed Rate Junior Subordinated Hybrid Notes, due 2054 (the "Hybrid Notes"). The Hybrid Notes are callable at the first reset date of October 15, 2034. AltaGas also executed a cross-currency swap arrangement to convert the underlying proceeds and interest costs into Canadian dollars, resulting in an effective annual interest rate of 6.90 percent over the initial ten year period of the notes. AltaGas intends to use the net proceeds of the Hybrid Notes to reduce the Company's outstanding senior notes and bank debt, and will receive 50 percent equity treatment for credit rating metrics.
- On September 30, 2024, AltaGas announced the conversion of the Cumulative Redeemable Floating Rate Preferred Shares, Series H (the "Series H Shares") into Cumulative Redeemable Five-Year Rate Reset Preferred Shares, Series G (the "Series G Shares") on a one for one basis and the subsequent cancellation and de-listing of the Series H Shares from the Toronto Stock Exchange ("TSX").
- On October 1, 2024, Washington Gas executed a note purchase agreement to issue US$200 million in private placement notes. US$100 million of these notes were issued on October 1, 2024 at 5.40 percent with a

maturity date of October 1, 2054 and the remaining US$100 million will be issued on April 1, 2025 at 4.84 percent with a maturity date of April 1, 2035. The proceeds will be used for general corporate purposes.

- Following a strong third quarter, AltaGas anticipates delivering fiscal 2024 results that will include normalized EBITDA[1] in the upper end of the guidance range of $1,675 million to $1,775 million while normalized EPS[1] is expected to be around the midpoint of the guidance range of $2.05 to $2.25.

CEO MESSAGE

"We're pleased with our strong third quarter results, which reflect the strength of our assets, strong demand for natural gas and NGLs and the continued execution of our strategic priorities," said Vern Yu, President and Chief Executive Officer. "Following the strong performance in the first nine months of the year, we are well positioned to deliver on our 2024 guidance and expect to produce normalized EBITDA towards the upper end of our guidance range while normalized EPS is expected to be closer to the midpoint of the guidance range."

"Performance in our Utilities business was ahead of our expectations and continues to deliver strong earnings, despite warmer-than-normal weather in Michigan and D.C. Strong year-over-year growth was driven by the partial settlement of Washington Gas' post-retirement benefit pension plan, continued capital investments across the network, and active cost management. We remain active advancing our regulatory priorities and ensuring rates are current and reflective of current capital investments and operating costs.

"Midstream performance was in line with our expectations, despite the rail interruptions due to the Alberta wildfires and the national rail strikes. The quarter included record global export volumes and double digit year-over-year growth in gas processing, fractionation and liquids handling, and extraction volumes. We continued to advance key Midstream commercial priorities, including a two new long-term agreements for gas processing, liquids handling and fractionation services at the Townsend facility, and extending the contract term for a marquee Canadian investment grade customer for an additional five years at Pipestone I. We also continued to advance long-term tolling arrangements across the global exports platform and expect to exceed previously committed tolling targets and will likely need to shift certain tolling volumes to the second phase of REEF.

"The fundamentals of our businesses are robust. Our gas utilities continue to realize strong growth from new customer additions, asset modernization investments, and system expansion. These robust demand trends are being augmented from the rapid rise in energy draws from data center growth in our service territory, which is providing AltaGas with incremental rate base growth opportunities in Northern Virginia and reinforcing the need for even more natural gas over the long-term.

"The outlook for our Midstream business is equally strong. Canadian natural gas supply will increase significantly through 2030 due to Canadian LNG exports and rising local demand. This will deliver strong associated natural gas liquids ("NGLs") supply that will need to be exported to global markets. Asia will continue to be the best market for Canadian LPGs where demand is expected to grow 45 percent through 2040.

"As we look ahead, we continue to expect the strategic importance of our assets to grow as they serve to link increasing energy supply to high demand centers, enabling AltaGas to deliver continued value for our customers."

RESULTS BY SEGMENT

Normalized EBITDA [(1)]		Three Months Ended September 30	
($ millions)		**2024**	2023
Utilities	**$**	**117**	$ 71
Midstream		**181**	185
Corporate/Other		**(4)**	(4)
Normalized EBITDA [(1)]	**$**	**294**	$ 252

(1) Non-GAAP financial measure; see discussion in Non-GAAP Financial Measures section of this news release.

Income (Loss) Before Income Taxes		Three Months Ended September 30	
($ millions)		**2024**	2023
Utilities	**$**	**24**	$ (16)
Midstream		**123**	61
Corporate/Other		**(127)**	(96)
Income (Loss) Before Income Taxes	**$**	**20**	$ (51)

BUSINESS PERFORMANCE

Midstream

The Midstream segment reported normalized EBITDA of $181 million in the third quarter of 2024 compared to $185 million in the third quarter of 2023, while income before income taxes was $123 million in the third quarter of 2024 compared to $61 million in the third quarter of 2023. These results were strong and in line with our expectations, despite the rail interruptions in Canada due to the Alberta wildfires and national rail strikes, which caused business interruptions and higher one-time operating costs. The quarter included record global export volumes and strong performance across the balance of the value chain, including double digit year-over-year growth in gas processing, fractionation and liquids handling, and extraction volumes.

AltaGas exported 128,272 Bbls/d of LPGs to Asia in the third quarter of 2024, including 11 Very Large Gas Carriers ("VLGCs") at RIPET, and 10 VLGCs at Ferndale. This represented a nine percent increase from the third quarter of 2023, which was principally driven by Ferndale volumes increasing by 22 percent and offsetting the majority of rail interruptions which largely impacted RIPET. This strong operating performance, despite these interruptions, reiterates the value of having multiple export terminals to overcome short-term impacts.

Despite extremely low Canadian natural gas prices during the third quarter of 2024, AltaGas did not experience any decline in throughput volumes due to production shut-ins. Year-over-year performance included a 10 percent increase in gas processing volumes, 12 percent increase in fractionation and liquids handling volumes, and 29 percent increase in extraction volumes. Volume growth was heavily weighted to AltaGas' Montney footprint, a trend we expect will continue in the years ahead. The strong fractionation volume growth was seen at North Pine, Harmattan and Younger. At North Pine, AltaGas completed optimization work that should allow the facility to consistently operate near 25,000 Bbls/d and meet our NEBC customers' desire for increased fractionation capacity.

MVP moved into full commercial operations in the quarter with 20-year firm service contracts with investment grade counterparties coming into effect July 1, 2024. The 2.0 Bcf/d pipeline is fully subscribed and is expandable by an additional 475 MMcf/d through low cost compression with extension into North Carolina through the Southgate project. MVP's financial contribution was modestly lower on a year-over-year basis in the third quarter of 2024, due to the larger AFUDC booked in the third quarter of 2023 versus the equity earnings that AltaGas is now recording with the pipeline in service.

AltaGas continued to advance key Midstream growth projects during the third quarter. Strong progress was made on REEF's in-water piling work for the jetty and the site's overburden activities, while compression, refrigeration and vessel fabrication work is advancing in controlled operating environments at offsite manufacturing facilities. At Pipestone II, construction is progressing to plan, including completion of the two acid gas injection wells and the majority of the gas gathering system, while compression, processing and fabrication work is progressing at offsite manufacturing facilities. Both midstream growth projects remain on schedule and on budget with 50 percent of REEF and 92 percent of Pipestone II project costs either incurred or under fixed price contracts.

Consistent with the Company's de-risking focus, AltaGas' Midstream operations are well-hedged for 2024 with approximately 87 percent of the remaining 2024 expected global export volumes tolled or financially hedged. Merchant volumes are hedged at an average Far East Index ("FEI") to North American financial hedge price of US$18.06/Bbl. Tolling volumes are in line with historical tolls. Approximately 80 percent of the Company's 2024 expected frac exposed volumes are hedged at US$24.54/Bbl, prior to transportation costs.

In line with AltaGas' traditional risk management activities, the Company expects to be actively locking in margins and further reducing commodity exposure over the fourth quarter of 2024 and first quarter of 2025 as we move into the 2025 NGL season, which runs from April 1, 2025 to March 31, 2026.

Midstream Hedge Program	Q4 2024	Q1 2025
Global Exports volumes hedged (%) (1)	87	86
Average propane/butane FEI to North America hedge (US$/Bbl) (2) (3)	18.06	19.28
Fractionation volume hedged (%) (3)	80	18
Frac spread hedge rate - (US$/Bbl) (3)	24.54	26.79

(1) Approximate expected volumes hedged. Includes contracted tolling volumes and financial hedges. Based on AltaGas' internally assumed export volumes. AltaGas is hedged at a higher percentage for firmly committed volumes.

(2) Does not include physical differential to FSK for C3 volumes. Butane is hedged as a percentage of WTI.

(3) Approximate average for the period.

Utilities

Utilities reported normalized EBITDA of $117 million in the third quarter of 2024 compared to $71 million in the third quarter of 2023, while income before income taxes was $24 million in the third quarter of 2024 compared to a loss of $16 million in the third quarter of 2023. Strong year-over-year growth was principally driven by the partial settlement of Washington Gas' post-retirement benefit pension plan, which was a de-risking activity that should reduce volatility of pension income in the years ahead, as well as contributions from continued capital investments focused on safety and reliability of the network, and active cost management. These positive factors were partially offset by the negative impact of the Maryland rate case, decreased asset optimization activities at Washington Gas and lower contributions from Retail due to the outsized performance present in the same quarter last year.

During the third quarter of 2024, AltaGas continued efforts on ensuring long-term operating costs are aligned with existing rate structures and allowed costs in each jurisdiction. These cost efficiencies will provide additional room for AltaGas to continue to make ongoing rate base investments to expand and modernize the network while minimizing the increase to customer bills. The Company will continue to prioritize cost management for the long-term benefit of our customers while maintaining regulatory and capital discipline.

AltaGas continued to actively invest across its Utilities assets during the third quarter of 2024 with $187 million of capital deployed across the Company's Utilities networks. This included investing nearly $100 million in the quarter through the Company’s various asset modernization programs and an additional $70 million for system betterment. These investments continue to be directed towards improving the safety and reliability of the system and connecting customers to the critical energy they require to carry out everyday life. AltaGas remains committed to making these investments, while balancing the need for ongoing customer affordability.

During the quarter, Washington Gas filed a rate case application to the Public Service Commission ("PSC") of D.C., seeking a US$46 million increase to base rates, including the transfer of US$12 million from the PROJECT*pipes 2* rate rider. Included in the filing was a proposed weather normalization adjustment that seeks to remove fluctuations in weather-related usage. Washington Gas also submitted its District SAFE ARP application, which aims to invest US$215 million over three years beginning May 2025. A final order for the ARP program is anticipated to align with the expiry of PROJECT*pipes* 2, which would allow for uninterrupted pipeline modernization work to ensure the ongoing safety of our customers while ensuring the timely recovery of capital.

Corporate/Other

In the Corporate/Other segment, normalized EBITDA was a loss of $4 million in the third quarter of 2024, consistent with the same quarter of 2023, while loss before income taxes was $127 million in the third quarter of 2024 compared to a loss of $96 million in the third quarter of 2023. Normalized EBITDA in the quarter was impacted by higher year-over-year contributions from Blythe, offset by higher expenses related to employee incentive plans, primarily as a result of the increasing share price in the third quarter of 2024.

CONSOLIDATED FINANCIAL RESULTS

	Three Months Ended September 30	
($ millions)	**2024**	2023
Normalized EBITDA [1]	**$ 294**	$ 252
Add (deduct):		
Depreciation and amortization	**(119)**	(109)
Interest expense	**(110)**	(95)
Normalized income tax expense	**(13)**	(10)
Preferred share dividends	**(5)**	(7)
Other [2]	**(5)**	(8)
Normalized net income [1][3]	**$ 42**	$ 23
Net income (loss) applicable to common shares	**$ 9**	$ (50)
Normalized funds from operations [1]	**$ 105**	$ 142
($ per share, except shares outstanding)		
Shares outstanding - basic (millions)		
During the period [4]	**298**	282
End of period	**298**	282
Normalized net income - basic [1][3]	**0.14**	0.08
Normalized net income - diluted [1][3]	**0.14**	0.08
Net loss per common share - basic	**0.03**	(0.18)
Net loss per common share - diluted	**0.03**	(0.18)

(1) Non-GAAP financial measure; see discussion in *Non-GAAP Financial Measures* section at the end of this news release.

(2) "Other" includes accretion expense, net income applicable to non-controlling interests, foreign exchange gains (losses), unrealized foreign exchange losses on intercompany balances and NCI portion of non-GAAP adjustments. The portion of non-GAAP adjustments applicable to non-controlling interests are excluded in the computation of normalized net income to ensure consistency of normalizations applied to controlling and non-controlling interests. These amounts are included in the “net income applicable to non-controlling interests” line item on the Consolidated Statements of Income.

(3) In the fourth quarter of 2023, AltaGas changed its non-GAAP policy to exclude the impact of unrealized foreign exchange losses (gains) on intercompany balances between Canadian and U.S. entities. Prior periods have been restated to reflect this change. Please refer to the Q3 2024 MD&A for additional details.

(4) Weighted average.

Normalized EBITDA for the third quarter of 2024 was $294 million compared to $252 million for the same quarter in 2023. The largest factors contributing to the year-over-year increase are described in the Business Performance sections above.

Income before income taxes was $20 million for the third quarter of 2024 compared to loss before income taxes of $51 million for the same quarter in 2023. The decrease in loss was mainly due to lower unrealized losses on risk management contracts, the same previously referenced factors impacting normalized EBITDA, proceeds received from an escrow account related to the 2019 disposition of AltaGas' investment in Meade Pipeline Co. LLC ("Meade"), which held WGL Midstream's indirect, non-operating interest in Central Penn pipeline ("Central Penn"), and lower transaction costs related to acquisitions and dispositions, partially offset by higher transition and restructuring costs, higher interest expense, higher depreciation and amortization expense, and lower foreign exchange gains. Please refer to the *"Three Months Ended September 30"* section of the Q3 2024 management's discussion and analysis ("MD&A") for further details on the variance in loss before income taxes and net income applicable to common shareholders.

Normalized net income was $42 million or $0.14 per share for the third quarter of 2024, compared to $23 million or $0.08 per share reported for the same quarter of 2023.

Normalized FFO was $105 million or $0.35 per share for the third quarter of 2024, compared to $142 million or $0.50 per share for the same quarter in 2023. The decrease was mainly due to the impact of non-cash items included in normalized EBITDA, higher normalized current income tax expense, higher interest expense, and foreign exchange losses compared to foreign exchange gains in the third quarter of 2023, partially offset by the same previously referenced factors impacting normalized EBITDA.

Interest expense for the third quarter of 2024 was $110 million, compared to $95 million for the same quarter in 2023. The increase was mainly due to higher average debt balances, incremental hybrid interest costs due to the issuance of additional Hybrid Notes in the third quarter of 2024 as well as the fourth quarter of 2023, higher average interest rates, and a higher average Canadian/U.S. dollar exchange rate, partially offset by higher capitalized interest. Interest expense recorded on the Hybrid Notes in the third quarter of 2024 was $15 million, compared to $9 million in the third quarter of 2023.

Income tax expense was $3 million for the third quarter of 2024, compared to an income tax recovery of $12 million for the same quarter of 2023. The decrease in income tax recovery was mainly due to higher income before income taxes.

FORWARD FOCUS, GUIDANCE AND FUNDING

AltaGas continues to execute on its long-term strategy of building a diversified platform that operates long-life energy infrastructure assets that connect customers and markets and are positioned to provide resilient and growing value for the Company’s stakeholders.

Following a strong third quarter of 2024, AltaGas is reiterating its previously disclosed 2024 guidance and expects to deliver results in the upper end of the normalized EBITDA range and near the midpoint of the normalized EPS range, as follows:

- 2024 normalized EPS guidance of $2.05 - $2.25, compared to normalized EPS of $1.90 and GAAP EPS of $2.27 in 2023; and
- 2024 normalized EBITDA guidance of $1,675 million - $1,775 million, compared to normalized EBITDA of $1,575 million and income before taxes of $912 million in 2023.

AltaGas is focused on delivering resilient and growing normalized EPS and normalized FFO per share while targeting lower leverage ratios. This strategy is designed to support steady dividend growth and provide the opportunity for ongoing capital appreciation for long-term shareholders.

AltaGas is maintaining a disciplined, self-funded 2024 capital program of approximately $1.3 billion, excluding asset retirement obligations ("ARO"). The Company is allocating approximately 53 percent of AltaGas' consolidated 2024 capital to its Utilities business, approximately 43 percent to the Midstream business and the balance to the Corporate/Other segment.

The Company expects to maintain an equity self-funding model in 2024, for the fifth consecutive year, and will fund capital requirements through a combination of internally generated cash flows and investment capacity associated with rising EBITDA levels. Asset sales will be considered on an opportunistic basis, with any potential proceeds to be used to reduce outstanding debt and continue to increase the financial flexibility of AltaGas.

QUARTERLY COMMON SHARE DIVIDEND AND PREFERRED SHARE DIVIDENDS

The Board of Directors approved the following schedule of Dividends:

Type [(1)]	Dividend (per share)	Period	Payment Date	Record
Common Shares	$0.2975	n.a.	31-Dec-24	16-Dec-24
Series A Preferred Shares	$0.19125	30-Sep-24 to 30-Dec-24	31-Dec-24	16-Dec-24
Series B Preferred Shares	$0.43141	30-Sep-24 to 30-Dec-24	31-Dec-24	16-Dec-24
Series G Preferred Shares	$0.376063	30-Sep-24 to 30-Dec-24	31-Dec-24	16-Dec-24

(1) Dividends on common shares and preferred shares are eligible dividends for Canadian income tax purposes.

CONFERENCE CALL AND WEBCAST

AltaGas will hold a conference call today, October 31, 2024, at 9:00 a.m. MT (11:00 a.m. ET) to discuss third quarter of 2024 results and other corporate developments.

Date:	Thursday, October 31, 2024
Time:	9:00 a.m. MT (11:00 a.m. ET)
Webcast:	https://app.webinar.net/5lXWpwZbZJM
Dial-in (Audio only):	+1 437-900-0527 or toll free at +1 888-510-2154

Shortly after the conclusion of the call a replay will be available on the Company's website or by dialing +1 289 819 1450 or toll free +1 888 660 6345. Passcode 13027 #.

AltaGas' Consolidated Financial Statements and accompanying notes for the third quarter of 2024, as well as its related MD&A, are now available online at www.altagas.ca. All documents will be filed with the Canadian securities regulatory authorities and will be posted under AltaGas' SEDAR+ profile at www.sedarplus.ca.

NON-GAAP MEASURES

This news release contains references to certain financial measures that do not have a standardized meaning prescribed by U.S. GAAP and may not be comparable to similar measures presented by other entities. The non-GAAP measures and their reconciliation to U.S. GAAP financial measures are shown below and within AltaGas' Management's Discussion and Analysis (MD&A) as at and for the period ended September 30, 2024. These non-GAAP measures provide additional information that Management believes is meaningful regarding AltaGas' operational performance, liquidity and capacity to fund dividends, capital expenditures, and other investing activities. Readers are cautioned that these non-GAAP measures should not be construed as alternatives to other measures of financial performance calculated in accordance with U.S. GAAP.

Change in Composition of Non-GAAP Measures

In the fourth quarter of 2023, Management changed the composition of certain of AltaGas' non-GAAP measures such that normalized net income now excludes the impact of unrealized intercompany foreign exchange gains (losses) resulting from intercompany balances between a U.S. subsidiary and a Canadian entity, where the foreign exchange impact in the U.S. subsidiary is recorded through gain (loss) on foreign currency translation in the Consolidated Statements of Comprehensive Income (Loss) and the Canadian entity revaluation is recorded through the foreign exchange gain (loss) line item on the Consolidated Statements of Income (Loss). This change was made as a result of Management's assessment that excluding these intercompany foreign exchange impacts from normalized net income is more representative of the Company's ongoing financial performance. Prior period calculations of the relevant non-GAAP measures have been restated to reflect this change. The following table summarizes the impact of this change on the periods presented in this news release:

Increase as result of change	Three Months Ended September 30		Nine Months Ended September 30	
($ millions, except where noted)	**2024**	2023	**2024**	2023
Normalized net income [1]	**$ —**	$ (5)	**$ —**	$ 1
Normalized income tax expense	**$ —**	$ (2)	**$ —**	$ —
Normalized effective tax rate (%)	**— %**	(0.8)%	**— %**	— %

(1) Corresponding per share amounts have also been adjusted.

Normalized EBITDA

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2024**	2023	**2024**	2023
Income (loss) before income taxes (GAAP financial measure)	**$ 20**	$ (51)	**$ 515**	$ 751
Add:				
Depreciation and amortization	**119**	109	**352**	331
Interest expense	**110**	95	**327**	293
EBITDA	**$ 249**	$ 153	**$ 1,194**	$ 1,375
Add (deduct):				
Transaction costs related to acquisitions and dispositions (1)	**2**	10	**9**	31
Unrealized losses (gains) on risk management contracts (2)	**37**	91	**10**	(24)
Gains on sale of assets (3)	**(14)**	—	**(12)**	(319)
Transition and restructuring costs (4)	**17**	1	**49**	6
Wind-up of pension plan (5)	**—**	—	**—**	2
Accretion expenses	**2**	3	**4**	8
Foreign exchange losses (gains) (6)	**1**	(6)	**(5)**	(6)
Normalized EBITDA	**$ 294**	$ 252	**$ 1,249**	$ 1,073

(1) Comprised of transaction costs related to acquisitions and dispositions of assets and/or equity investments in the period. These costs are included in the "cost of sales" and "operating and administrative" line items on the Consolidated Statements of Income (Loss). Transaction costs include expenses, such as legal fees, that are directly attributable to the acquisition or disposition.

(2) Included in the “revenue”, “cost of sales”, and "foreign exchange gains (losses)" line items on the Consolidated Statements of Income (Loss). Please refer to Note 13 of the unaudited condensed interim Consolidated Financial Statements as at and for the three and nine months ended September 30, 2024 for further details regarding AltaGas’ risk management activities.

(3) Included in the “other income” line item on the Consolidated Statements of Income (Loss).

(4) Comprised of transition and restructuring costs (including CEO transition). These costs are included in the "operating and administrative" line item on the Consolidated Statements of Income (Loss).

(5) Relates to the completion of the wind-up of the Canadian defined benefit pension plan in the second quarter of 2023. The associated costs are included in the "other income" line on the Consolidated Statements of Income (Loss).

(6) Excludes unrealized losses (gains) on foreign exchange forward contracts that have been entered into for the purpose of cash management. These losses (gains) are included above in the line "unrealized losses (gains) on risk management contracts".

EBITDA is a measure of AltaGas' operating profitability prior to how business activities are financed, assets are amortized, or earnings are taxed. EBITDA is calculated from the Consolidated Statements of Income (Loss) using income (loss) before income taxes adjusted for pre-tax depreciation and amortization and interest expense.

AltaGas presents normalized EBITDA as a supplemental measure. Normalized EBITDA is used by Management to enhance the understanding of AltaGas' earnings over periods, as well as for budgeting and compensation related purposes. The metric is frequently used by analysts and investors in the evaluation of entities within the industry as it excludes items that can vary substantially between entities depending on the accounting policies chosen, the book value of assets, and the capital structure.

Normalized Net Income

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2024**	2023	**2024**	2023
Net income (loss) applicable to common shares (GAAP financial measure)	**$ 9**	$ (50)	**$ 375**	$ 528
Add (deduct) after-tax:				
Transaction costs related to acquisitions and dispositions (1)	**1**	7	**7**	22
Unrealized losses (gains) on risk management contracts (2)	**28**	70	**7**	(19)
Gains on sale of assets (3)	**(10)**	—	**(6)**	(217)
Transition and restructuring costs (4)	**13**	1	**37**	5
Wind-up of pension plan (5)	**—**	—	**—**	2
Unrealized foreign exchange losses (gains) on intercompany balances (6)	**1**	(5)	**1**	1
Normalized net income	**$ 42**	$ 23	**$ 421**	$ 322

(1) Comprised of transaction costs related to acquisitions and dispositions of assets and/or equity investments in the period. The pre-tax costs are included in the "cost of sales" and "operating and administrative" line items on the Consolidated Statements of Income (Loss). Transaction costs include expenses, such as legal fees, which are directly attributable to the acquisition or disposition.

(2) The pre-tax amounts are included in the "revenue", "cost of sales", and "foreign exchange gains (losses)" line items on the Consolidated Statements of Income (Loss). Please refer to Note 13 of the unaudited condensed interim Consolidated Financial Statements as at and for the three and nine months ended September 30, 2024 for further details regarding AltaGas' risk management activities.

(3) The pre-tax amounts are included in the "other income" line item on the Consolidated Statements of Income (Loss).

(4) Comprised of transition and restructuring costs (including CEO transition). The pre-tax costs are included in the "operating and administrative" line item on the Consolidated Statements of Income (Loss).

(5) Relates to the completion of the wind-up of the Canadian defined benefit pension plan in the second quarter of 2023. The associated costs are included in the "other income" line on the Consolidated Statements of Income.

(6) Relates to unrealized foreign exchange losses (gains) on intercompany accounts receivable and accounts payable balances between a U.S. subsidiary and a Canadian entity, where the impact to the U.S. subsidiary is recorded through accumulated other comprehensive income as a loss on foreign currency translation, and the impact to the Canadian entity is recorded through the "foreign exchange gains" line item on the Consolidated Statements of Income (Loss). In the fourth quarter of 2023, AltaGas changed its non-GAAP policy to exclude the impact of unrealized foreign exchange losses (gains) on intercompany balances between Canadian and U.S. entities. The amounts presented in this table reflect the restated figures to align with the revised policy. Please refer to the Q3 2024 MD&A for further details.

Normalized net income and normalized net income per share are used by Management to enhance the comparability of AltaGas' earnings, as these metrics reflect the underlying performance of AltaGas' business activities.

Normalized Funds from Operations

		Three Months Ended September 30		Nine Months Ended September 30	
($ millions)		**2024**	2023	**2024**	2023
Cash from operations (GAAP financial measure)	**$**	**21**	$ 3	**$ 1,030**	$ 967
Add (deduct):					
Net change in operating assets and liabilities		**64**	124	**(301)**	(298)
Asset retirement obligations settled		**1**	7	**1**	12
Funds from operations	**$**	**86**	$ 134	**$ 730**	$ 681
Add (deduct):					
Transaction costs related to acquisitions and dispositions (1)		**2**	10	**9**	31
Transition and restructuring costs (2)		**17**	1	**49**	6
Current tax expense (recovery) on asset sales (3)		**—**	(3)	**7**	34
Normalized funds from operations	**$**	**105**	$ 142	**$ 795**	$ 752

(1) Comprised of transaction costs related to acquisitions and dispositions of assets and/or equity investments in the period. These costs exclude non-cash amounts and are included in the "cost of sales" and "operating and administrative" line items on the Consolidated Statements of Income (Loss). Transaction costs include expenses, such as legal fees, which are directly attributable to the acquisition or disposition.

(2) Comprised of transition and restructuring costs (including CEO transition). The pre-tax costs are included in the "operating and administrative" line item on the Consolidated Statements of Income (Loss).

(3) Included in the "current income tax expense (recovery)" line item on the Consolidated Statements of Income (Loss).

Normalized funds from operations and funds from operations are used to assist Management and investors in analyzing the liquidity of the Corporation. Management uses these measures to understand the ability to generate funds for capital investments, debt repayment, dividend payments, and other investing activities.

Invested Capital and Net Invested Capital

		Three Months Ended September 30		Nine Months Ended September 30	
($ millions)		**2024**	2023	**2024**	2023
Cash used in (from) investing activities (GAAP financial measure)	**$**	**393**	$ 243	**$ 973**	$ (395)
Add (deduct):					
Net change in non-cash capital expenditures (1)		**23**	12	**20**	(23)
Contributions from non-controlling interests		**(56)**	—	**(73)**	—
Net Invested Capital	**$**	**360**	$ 255	**$ 920**	$ (418)
Asset dispositions		**—**	1	**2**	1,073
Disposal of equity method investments (2)		**14**	1	**14**	1
Invested capital	**$**	**374**	$ 257	**$ 936**	$ 656

(1) Comprised of non-cash capital expenditures included in the "accounts payable and accrued liabilities" line item on the Consolidated Balance Sheets. Please refer to Note 20 of the unaudited condensed interim Consolidated Financial Statements as at and for the three and nine months ended September 30, 2024 for further details.

(2) Relates to escrow account proceeds received from AltaGas' previous investment in Meade which held WGL Midstream's indirect, non-operating interest in Central Penn. Upon close of the sale in 2019, various escrow accounts were established to provide the purchaser a form of recourse for the settlement of indemnification obligations.

Invested capital is a measure of AltaGas' use of funds for capital expenditure activities. It includes expenditures relating to property, plant, and equipment and intangible assets, capital contributed to long term investments, and contributions from non-controlling interests. Net invested capital is invested capital presented net of proceeds from disposals of assets in the period. Net invested capital is calculated based on the investing activities section in the Consolidated Statements of Cash Flows, adjusted for items including the net change in non-cash capital expenditures and contributions from non-controlling interests. Invested capital and net invested capital are used by Management, investors, and analysts to enhance the understanding of AltaGas' capital expenditures from period to period and provide additional detail on the Company's use of capital.

CONSOLIDATED FINANCIAL REVIEW

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions, except effective income tax rates)	**2024**	2023	**2024**	2023
Revenue	**2,759**	3,030	**9,189**	9,709
Normalized EBITDA [(1)]	**294**	252	**1,249**	1,073
Income (loss) before income taxes	**20**	(51)	**515**	751
Net income (loss) applicable to common shares	**9**	(50)	**375**	528
Normalized net income [(1) (2)]	**42**	23	**421**	322
Total assets	**24,748**	22,183	**24,748**	22,183
Total long-term liabilities	**13,467**	11,073	**13,467**	11,073
Invested capital [(1)]	**374**	257	**936**	656
Cash from (used in) investing activities	**(393)**	(243)	**(973)**	395
Dividends declared [(3)]	**89**	79	**265**	237
Cash from operations	**21**	3	**1,030**	967
Normalized funds from operations [(1)]	**105**	142	**795**	752
Normalized effective income tax rate (%) [(1) (2)]	**20.6**	22.7	**22.2**	20.6
Effective income tax rate (%) [(4)]	**16.7**	23.2	**22.6**	25.3

	Three Months Ended September 30		Nine Months Ended September 30	
($ per share, except shares outstanding)	**2024**	2023	**2024**	2023
Net income (loss) per common share - basic	**0.03**	(0.18)	**1.26**	1.87
Net income (loss) per common share - diluted	**0.03**	(0.18)	**1.26**	1.86
Normalized net income - basic [(1) (2)]	**0.14**	0.08	**1.42**	1.14
Normalized net income - diluted [(1) (2)]	**0.14**	0.08	**1.41**	1.14
Dividends declared [(3)]	**0.30**	0.28	**0.89**	0.84
Cash from operations	**0.07**	0.01	**3.48**	3.43
Normalized funds from operations [(1)]	**0.35**	0.50	**2.69**	2.67
Shares outstanding - basic (millions)				
During the period [(5)]	**298**	282	**296**	282
End of period	**298**	282	**298**	282

(1) Non-GAAP financial measure or non-GAAP financial ratio; see discussion in *Non-GAAP Financial Measures* section of the MD&A.

(2) In the fourth quarter of 2023, AltaGas changed its non-GAAP policy to exclude the impact of unrealized foreign exchange losses (gains) on intercompany balances between Canadian and U.S. entities. Prior periods have been restated to reflect this change. Please refer to the Q2 2024 MD&A for additional details.

(3) Dividends declared per common share per quarter: $0.28 per share beginning March 2023, increased to $0.2975 per share effective March 2024.

(4) The decrease in the effective income tax rate for the three months ended September 30, 2024 is due to the composition of income before income taxes.

(5) Weighted average.

ABOUT ALTAGAS

AltaGas is a leading North American infrastructure company that connects customers and markets to affordable and reliable sources of energy. The Company operates a diversified, lower-risk, high-growth Utilities and Midstream business that is focused on delivering resilient and durable value for its stakeholders.

For more information visit www.altagas.ca or reach out to one of the following:

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FORWARD-LOOKING INFORMATION

This news release contains forward-looking information (forward-looking statements). Words such as "may", "can", "would", "could", "should", "likely", "will", "intend", "plan", "anticipate", "believe", "aim", "seek", "future", "commit", "propose", "contemplate", "estimate", "focus", "strive", "forecast", "expect", "project", "potential", "target", "guarantee", "potential", "objective", "continue", "outlook", "guidance", "growth", "long-term", "vision", "opportunity" and similar expressions suggesting future events or future performance, as they relate to the Company or any affiliate of the Company, are intended to identify forward-looking statements. In particular, this news release contains forward-looking statements with respect to, among other things, business objectives, expected growth, results of operations, performance, business projects and opportunities and financial results. Specifically, such forward-looking statements included in this document include, but are not limited to, statements with respect to the following: the Company's 2024 guidance including normalized earnings per share of $2.05 to $2.25 and normalized EBITDA of $1,675 to $1,775 million; the Company's expectation that it will deliver fiscal 2024 results toward the upper end of the guidance range for normalized EBITDA and toward the midpoint of the guidance range for normalized EPS; the status of negotiations and long-term tolling agreements for the first phase capacity for REEF; the expectation that the Company will enter into definitive agreements for long-term tolling arrangements; AltaGas' target of 60 percent of it export volumes being under long-term tolling agreements and the timing thereof; the Company's commitment to driving the best collective outcomes for stakeholders through leveraging its assets to connect upstream and downstream customers and markets; progress on the construction and de-risking of REEF and the project remaining on schedule and on budget; progress on the construction of the Pipestone II expansion project and the project remaining on schedule and on budget; AltaGas' intention to divest its 10 percent interest in MVP; the anticipated use of proceeds of the Hybrid Notes; Washington Gas' issuance of US$100 million 4.84 percent private placement notes on April 1, 2025 and the anticipated use of proceeds therefrom; AltaGas' ability to execute on its strategic priorities; the Company actively advancing its regulatory priorities in the Utilities business; the advancement of long-term tolling arrangements across the global exports platform and the expectation that AltaGas will exceed its previously committed tolling targets and need to shift certain tolling volumes to the second phase of REEF; expected growth opportunities in Northern Virginia and long-term demand for natural gas; the expectation that Canadian natural gas supply will increase through 2030, associated NGL supply and the need to export to global markets; the expectation that demand for Canadian LPGs in Asia will grow 45 percent through 2040; the expectation that AltaGas' assets will link growing energy supply and demand; anticipated volume growth in AltaGas' Montney footprint; the Company's focus on de-risking its *business, actively locking in margins and further reducing commodity exposure over the fourth quarter of 2024 and the first quarter of 2025; the Company's hedging program and AltaGas' 2024 Midstream Hedge Program quarterly estimates; the Company's ability to continue making rate base investments and the benefits therefrom; AltaGas' continued investment in its Utilities business, the benefits therefrom and its ability to deliver energy to its customers; AltaGas' intention to manage costs for the long-term benefits of its customers while maintaining regulatory and capital discipline; the anticipated benefits of the final order for the ARP program; AltaGas' ability to execute its long-term corporate strategy; AltaGas' focus on growing normalized EPS and FFO per share while targeting lower leverage ratios; AltaGas' commitment to maintaining an disciplined, self-funded 2024 capital program of approximately $1.3 billion, excluding ARO; the allocation of consolidated 2024 capital to the Company's Utilities, Midstream and Corporate/Other segments; AltaGas' commitment to maintaining an equity self-funding model in 2024 and that it will fund capital requirements through a combination of internally generated cash flows and investment capacity associated with rising EBITDA; consideration of opportunistic asset sales and the anticipated use of proceeds therefrom; and AltaGas' dividend policy.*

These statements involve known and unknown risks, uncertainties and other factors that may cause actual results, events, and achievements to differ materially from those expressed or implied by such statements. Such statements reflect AltaGas' current expectations, estimates, and projections based on certain material factors and assumptions at the time the statement was made. Material assumptions include: effective tax rates; U.S./Canadian dollar exchange rates; inflation; interest rates, credit ratings, regulatory approvals and policies; expected commodity supply, demand and pricing; volumes and rates; propane price differentials; degree day variance from normal; pension discount rate; financing initiatives; the performance of the businesses underlying each sector; impacts of the hedging program; weather; frac spread; access to capital; future operating and capital costs; timing and receipt of regulatory approvals; seasonality; planned and unplanned plant outages; timing of in-service dates of new projects and acquisition and divestiture activities; taxes; operational expenses; returns on investments; dividend levels; and transaction costs.

AltaGas' forward-looking statements are subject to certain risks and uncertainties which could cause results or events to differ from current expectations, including, without limitation: health and safety risks; operating risks; infrastructure; natural gas supply risks; volume throughput; service interruptions; transportation of petroleum products; market risk; inflation; general economic conditions; cybersecurity, information, and control systems; climate-related risks; environmental regulation risks; regulatory risks; litigation; changes in law; Indigenous and treaty rights; dependence on certain partners; political uncertainty and civil unrest; risks related to conflict, including the conflicts in Eastern Europe and the Middle East; decommissioning, abandonment and reclamation costs; reputation risk; weather data; capital market and liquidity risks; interest rates; internal credit risk; foreign exchange risk; debt financing, refinancing, and debt service risk; counterparty and supplier risk; technical systems and processes incidents; growth strategy risk; construction and development; underinsured and uninsured losses; impact of competition in AltaGas' businesses; counterparty credit risk; composition risk; collateral; rep agreements; market value of common shares and other securities; variability of dividends; potential sales of additional shares; labor relations; key personnel; risk management costs and limitations; cost of providing retirement plan benefits; failure of service providers; risks related to pandemics, epidemics or disease outbreaks; and the other factors discussed under the heading "Risk Factors" in the Company's Annual Information Form for the year ended December 31, 2023 ("AIF") and set out in AltaGas' other continuous disclosure documents.

Many factors could cause AltaGas' or any particular business segment's actual results, performance or achievements to vary from those described in this press release, including, without limitation, those listed above and the assumptions upon which they are based proving incorrect. These factors should not be construed as exhaustive. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this news release as intended, planned, anticipated, believed, sought, proposed, estimated, forecasted, expected, projected or targeted and such forward-looking statements included in this news release, should not be unduly relied upon. The impact of any one assumption, risk, uncertainty, or other factor on a particular forward-looking statement cannot be determined with certainty because they are interdependent and AltaGas' future decisions and actions will depend on management's assessment of all information at the relevant time. Such statements speak only as of the date of this news release. AltaGas does not intend, and does not assume any obligation, to update these forward-looking statements except as required by law. The forward-looking statements contained in this news release are expressly qualified by these cautionary statements.

Financial outlook information contained in this news release about prospective financial performance, financial position, or cash flows is based on assumptions about future events, including economic conditions and proposed *courses of action, based on AltaGas management's assessment of the relevant information currently available. Readers are cautioned that such financial outlook information contained in this news release should not be used for purposes other than for which it is disclosed herein.*

Additional information relating to AltaGas, including its quarterly and annual MD&A and Consolidated Financial Statements, AIF, and press releases are available through AltaGas' website at www.altagas.ca or through SEDAR+ at www.sedarplus.ca.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") dated October 30, 2024 is provided to enable readers to assess the results of operations, liquidity, and capital resources of AltaGas Ltd. ("AltaGas", the "Company" or the "Corporation") as at and for the three and nine months ended September 30, 2024. This MD&A should be read in conjunction with the accompanying unaudited condensed interim Consolidated Financial Statements and notes thereto of AltaGas as at and for the three and nine months ended September 30, 2024 and the audited Consolidated Financial Statements and MD&A as at and for the year ended December 31, 2023.

The Consolidated Financial Statements and comparative information have been prepared in accordance with United States ("U.S.") generally accepted accounting principles ("U.S. GAAP") and in Canadian dollars, unless otherwise indicated. Throughout this MD&A, references to GAAP refer to U.S. GAAP and dollars refer to Canadian dollars, unless otherwise indicated.

Abbreviations, acronyms, and capitalized terms used in this MD&A without express definition shall have the same meanings given to those terms in the MD&A as at and for the year ended December 31, 2023 or the Annual Information Form for the year ended December 31, 2023.

This MD&A contains forward-looking information ("forward-looking statements"). Words such as "may", "can", "would", "could", "should", "will", "intend", "plan", "anticipate", "believe", "aim", "seek", "propose", "contemplate", "estimate", "focus", "strive", "forecast", "expect", "project", "target", "potential", "objective", "continue", "outlook", "vision", "opportunity" and similar expressions suggesting future events or future performance, as they relate to the Corporation or any affiliate of the Corporation, are intended to identify forward-looking statements. In particular, this MD&A contains forward-looking statements with respect to, among other things, business objectives, expected growth, results of operations, performance, business projects and opportunities and financial results. Specifically, such forward-looking statements included in this document include, but are not limited to, statements with respect to the following: AltaGas' belief in the role and importance of global resource exports; the status of negotiations and long-term tolling arrangements for first phase capacity for REEF; AltaGas' target of 60 percent of its export volumes being under long-term tolling agreements and the timing thereof; the Company's commitment to driving the best collective outcomes for stakeholders through leveraging its assets to connect upstream and downstream customers and markets; progress on the construction and de-risking of REEF and the project remaining on schedule and on budget; progress on the construction of the Pipestone II expansion project and the project remaining on schedule and on budget; the anticipated use of proceeds of the Hybrid Notes; AltaGas' 2024 guidance including normalized earnings per share of $2.05 to $2.25 and normalized EBITDA of $1.675 billion to $1.775 billion; the Company's expectation that it will deliver fiscal 2024 results towards the upper end of the guidance range for normalized EBITDA and towards the midpoint of the guidance range for normalized EPS; Washington Gas' issuance of US$100 million 4.84 percent private placement notes on April 1, 2025 and the anticipated use of proceeds therefrom; the expectation that the Utilities segment will contribute approximately 55 percent of normalized EBITDA for 2024; expected growth drivers of normalized EBITDA in the Utilities segment; the expectation that the Midstream segment will contribute approximately 45 percent of normalized EBITDA for 2024; drivers of expected growth in the Midstream segment; expected growth drivers of 2024 normalized earnings per share; AltaGas' focus on de-risking its business and managing direct commodity price exposure; the Company's intention to maintain an active hedging program and the anticipated outcomes therefrom; AltaGas' 2024 Midstream Hedge Program quarterly estimates; estimated impact of changes in commodity prices, exchange rates, discount rates and weather on normalized annual results for 2024; AltaGas' commitment to maintaining a disciplined, self-funded capital program; expected invested capital expenditures of approximately $1.3 billion in 2024; anticipated segment allocation and focus of capital expenditures in 2024; the expectation that AltaGas' 2024 committed capital program will be funded through internally-generated cash flow, asset sales and senior debt; the estimated cost, status and expected in-service dates for growth capital projects in the Midstream and Utilities businesses; anticipated benefits of the Pipestone Phase II expansion project; the expectation that REEF will be developed in phases and the anticipated benefits therefrom, projected capital expenditures on REEF and *expected timing of REEF coming online; AltaGas' responsibilities with respect to the construction and operation of REEF; anticipated timing of finalizing the redesigned project scope of MVP Southgate, timing for completion of the MVP Southgate project and the anticipated benefits therefrom; Washington Gas' ARP replacement programs and the expected benefits therefrom; SEMCO Energy's MRP and IRIP programs; expected filing, procedure and decision dates for rate cases in the Utilities business; timing of material regulatory filings, proceedings and decisions in the Utilities business; the PSC of DC's approval of AltaGas' and DCG's proposed consent decree and expected penalties for breaching merger commitments associated with the WGL Acquisition; Washington Gas' Prince William County biogas pipeline and the SCC of VA's approval of a Rider RNG; the expectation that the restrictions on Washington Gas' ability to pay dividends to AltaGas as a result of certain commitments in respect of the WGL Acquisition will not have an impact on AltaGas' ability to meet its obligations; anticipated timing for commencement of AltaGas' two leased VLGCs; AltaGas' objective for managing capital; AltaGas' 2024 strategic priorities; and AltaGas' dividend policy.*

These statements involve known and unknown risks, uncertainties and other factors that may cause actual results, events and achievements to differ materially from those expressed or implied by such statements. Such statements reflect AltaGas' current expectations, estimates, and projections based on certain material factors and assumptions at the time the statement was made. Material assumptions include: effective tax rates; U.S./Canadian dollar exchange rates; inflation; interest rates, credit ratings, regulatory approvals and policies; expected commodity supply, demand and pricing; volumes and rates; propane price differentials; degree day variance from normal; pension discount rate; financing initiatives; the performance of the businesses underlying each sector; impacts of the hedging program; weather; frac spread; access to capital; future operating and capital costs; timing and receipt of regulatory approvals; seasonality; planned and unplanned plant outages; timing of in-service dates of new projects and acquisition and divestiture activities; taxes; operational expenses; returns on investments; dividend levels; and transaction costs.

AltaGas' forward-looking statements are subject to certain risks and uncertainties which could cause results or events to differ from current expectations, including, without limitation: health and safety risks; operating risks; infrastructure; natural gas supply risks; volume throughput; service interruptions; transportation of petroleum products; market risk; inflation; general economic conditions; cybersecurity, information, and control systems; climate-related risks; environmental regulation risks; regulatory risks; litigation; changes in law; Indigenous and treaty rights; dependence on certain partners; political uncertainty and civil unrest; risks related to conflict, including the conflicts in Eastern Europe and the Middle East; decommissioning, abandonment and reclamation costs; reputation risk; weather data; capital market and liquidity risks; interest rates; internal credit risk; foreign exchange risk; debt financing, refinancing, and debt service risk; counterparty and supplier risk; technical systems and processes incidents; growth strategy risk; construction and development; underinsured and uninsured losses; impact of competition in AltaGas' businesses; counterparty credit risk; composition risk; collateral; rep agreements; market value of the common shares and other securities; variability of dividends; potential sales of additional shares; labor relations; key personnel; risk management costs and limitations; commitments associated with regulatory approvals for the acquisition of WGL; cost of providing retirement plan benefits; failure of service providers; risks related to pandemics, epidemics or disease outbreaks; and the other factors discussed under the heading "Risk Factors" in the Corporation's Annual Information Form for the year ended December 31, 2023 ("AIF") and set out in AltaGas' other continuous disclosure documents.

Many factors could cause AltaGas' or any particular business segment's actual results, performance or achievements to vary from those described in this MD&A, including, without limitation, those listed above and the assumptions upon which they are based proving incorrect. These factors should not be construed as exhaustive. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this MD&A as intended, planned, anticipated, believed, sought, proposed, estimated, forecasted, expected, projected or targeted and such forward-looking statements included in this MD&A, should not be unduly relied upon. The impact of any one assumption, risk, uncertainty, or other factor on a particular forward-looking statement cannot be determined with certainty because they are interdependent and AltaGas' future decisions and actions will depend on

Management's assessment of all information at the relevant time. Such statements speak only as of the date of this MD&A. AltaGas does not intend, and does not assume any obligation, to update these forward-looking statements except as required by law. The forward-looking statements contained in this MD&A are expressly qualified by these cautionary statements.

Financial outlook information contained in this MD&A about prospective financial performance, financial position, or cash flows is based on assumptions about future events, including economic conditions and proposed courses of action, based on AltaGas Management's assessment of the relevant information currently available. Readers are cautioned that such financial outlook information contained in this MD&A should not be used for purposes other than for which it is disclosed herein.

Additional information relating to AltaGas, including its quarterly and annual MD&A and Consolidated Financial Statements, Annual Information Form, and press releases are available through AltaGas' website at www.altagas.ca or through SEDAR+ at www.sedarplus.ca.

AltaGas Business Overview and Organization

AltaGas is a leading North American energy infrastructure company that connects customers and markets to affordable and reliable sources of energy. The Company operates a diversified, lower-risk, high-growth energy infrastructure business that is focused on delivering resilient and durable value for its stakeholders. AltaGas has three reporting segments - Utilities, Midstream, and Corporate/Other.

Utilities Segment

AltaGas' Utilities segment owns and operates franchised, cost-of-service, rate-regulated natural gas distribution and storage utilities that are focused on providing safe, reliable, and affordable energy to its customers. AltaGas' Utilities provided energy to approximately 1.6 million residential and commercial customers in the third quarter of 2024 with an average rate base of approximately US$5.3 billion.

The Utilities segment includes two utilities that operate across four major U.S. jurisdictions:

- Washington Gas Light Company ("Washington Gas"), which is the Company's largest operating utility that serves approximately 1.2 million customers across Maryland, Virginia and the District of Columbia; and
- SEMCO Energy, Inc. ("SEMCO Energy"), which delivers essential energy to approximately 327,000 customers in Southern Michigan and Michigan's Upper Peninsula.

The Utilities segment also includes other storage facilities and contracts for interstate natural gas transportation and storage services, as well as WGL Energy Services, Inc. ("WGL Energy Services"), an affiliated retail energy marketing business, which sells natural gas and electricity directly to residential, commercial, and industrial customers located in Maryland, Virginia, Delaware, Pennsylvania, Ohio, and the District of Columbia ("D.C."). AltaGas also previously owned ENSTAR Natural Gas Company and a 65 percent indirect interest in Cook Inlet Natural Gas Storage Alaska ("CINGSA") and other ancillary operations in Alaska (the "Alaska Utilities"), which were divested to TriSummit Utilities Inc. on March 1, 2023 (the "Alaska Utilities Disposition").

Midstream Segment

AltaGas' Midstream segment is a leading North American platform that connects customers and markets. From wellhead to tidewater, the Company is focused on providing its customers with safe and reliable service and connectivity that facilitates the best outcomes for their businesses. This includes global market access for North American Liquified Petroleum Gases ("LPGs"), which provides North American producers and aggregators with attractive netbacks for propane and butane while delivering diversity of supply and supporting stronger energy security in Asia to AltaGas' downstream customers.

Throughout AltaGas’ Midstream operations, the Company is playing a vital role within the larger energy ecosystem that keeps the global economy moving forward in a safe, reliable and affordable manner.

AltaGas’ Midstream platform is heavily focused on the Montney and Deep Basin resource plays and centers around global exports, which is where the Company believes the market is headed for Canadian resource development over the long-term. AltaGas also operates a broader set of midstream infrastructure assets across the Western Canadian Sedimentary Basin ("WCSB") and select regions in the U.S., which are all focused on connecting customers and markets in the most efficient manner possible.

There are three core pillars to AltaGas’ Midstream platform that are integral to each other and facilitate the Company’s wellhead to tidewater and beyond value chain. These include:

- **Global Exports**, which includes AltaGas’ two operational LPG export terminals where the Company has capacity to export up to 150,000 Bbl/d of propane and butane to key markets in Asia;
- **Natural Gas Gathering, Processing and Extraction**, which includes 1.2 Bcf/d of extraction processing capacity and approximately 1.2 Bcf/d of raw field gas processing capacity, which is heavily focused on the Montney and Deep Basin; and
- **Fractionation and Liquids Handling**, which includes 65 MBbl/d of fractionation capacity and a sizable liquids handling footprint.

The Midstream segment also consists of natural gas and natural gas liquids ("NGLs") marketing businesses, domestic logistics, trucking and rail terminals, and approximately 3.2 million barrels of liquid storage capability through a network of underground salt caverns through the Company’s Strathcona Storage JV with ATCO Energy Solutions Ltd., 15 Bcf of natural gas storage through the Dimsdale natural gas storage facility ("Dimsdale") which was acquired as part of AltaGas' acquisition of natural gas processing and storage infrastructure assets in the Pipestone area of the Alberta Montney (the "Pipestone Acquisition" or "Pipestone Assets") in December 2023, as well as AltaGas’ 10 percent interest in the Mountain Valley Pipeline ("MVP").

Corporate/Other Segment

AltaGas’ Corporate/Other segment consists of the Company’s corporate activities and a small portfolio of gas-fired power generation and distribution assets capable of generating 508 MW of power primarily in California.

Third Quarter Highlights

(Normalized EBITDA, normalized funds from operations, and normalized net income are non-GAAP financial measures. Normalized funds from operations per share and normalized net income per share are non-GAAP ratios. Please see Non-GAAP Financial Measures section of this MD&A.)

- Normalized earnings per share ("EPS") was $0.14 in the third quarter of 2024 compared to $0.08 in the third quarter of 2023, while GAAP EPS was $0.03 in the third quarter of 2024 compared to a loss of $0.18 in the third quarter of 2023. Normalized EPS growth was primarily driven by strong Utilities performance.
- Normalized EBITDA was $294 million in the third quarter of 2024 compared to $252 million in the third quarter of 2023, while income before income taxes was $20 million in the third quarter of 2024 compared to a loss before income taxes of $51 million in the third quarter of 2023. The 17 percent year-over-year growth in normalized EBITDA was principally driven by strong Utilities performance, as outlined below.
- Normalized funds from operations per share was $0.35 in the third quarter of 2024 compared to $0.50 in the third quarter of 2023, while cash from operations per share was $0.07 in the third quarter of 2024 compared to $0.01 in the third quarter of 2023.
- The Utilities segment reported normalized EBITDA of $117 million in the third quarter of 2024 compared to $71 million in the third quarter of 2023, while income before income taxes was $24 million in the third quarter of 2024 compared to a loss before income taxes of $16 million in the third quarter of 2023. Strong year-over-year growth was principally driven by the partial settlement of Washington Gas' post-retirement benefit pension plan, contributions from rate base and accelerated replacement programs ("ARP") investment, and enhanced cost controls.
- The Midstream segment reported normalized EBITDA of $181 million in the third quarter of 2024 compared to $185 million in the third quarter of 2023, while income before income taxes was $123 million in the third quarter of 2024 compared to $61 million in the third quarter of 2023. Despite rail outages due to the Alberta wildfires and national rail strike that drove higher one-time operating costs, AltaGas was able to deliver strong financial performance due to operational execution.
- AltaGas exported a record of 128,272 Bbl/d of LPGs to Asia in the quarter, a nine percent year-over-year increase. Strong export volumes and contributions from the Pipestone assets were offset by lower export margins (including the impact of higher percentage of tolling contracts), higher long-term incentive costs due to AltaGas' rising share price, and a lower year-over-year contribution from MVP as the asset was placed into service with equity earnings below the Allowance for Funds Used During Construction ("AFUDC") in the third quarter of 2023.
- AltaGas continued to advance key Midstream commercial priorities during and subsequent to the quarter, including:
    - Entering two agreements that have a high-single digit average contract length with a large investment grade international energy company in Northeastern B.C. ("NEBC") for a total of 100 Mmcf/d of gas processing capacity at the Townsend facility, along with associated liquids handling and fractionation services;
    - Extending the contract term with a large Canadian investment grade producer at the Pipestone I gas processing facility in the Alberta Montney for an additional five years, including gas processing, liquids handling and marketing services; and
    - Advancing long-term tolling arrangements across the global exports platform with a number of agreements now in definitive documentation stages. This includes AltaGas having contracts in hand or being in active negotiations for more than 100 percent of first phase capacity for the Ridley Island Energy Export Facility ("REEF"). AltaGas continues to target having 60 percent of its export volumes under long-term tolling agreements by the start of the 2027 NGL year.
- The ongoing commercial success reiterates the strategic advantages of AltaGas' assets across NEBC, the Alberta Montney, and the global exports value chain. The Company continues to look forward to

leveraging its assets to connect upstream and downstream customers and markets and drive the best collective outcomes for all stakeholders.

- AltaGas remained active from a regulatory perspective during the third quarter, including filing a rate case and proposed accelerated replacement program ("ARP") extension in the District of Columbia. The District Strategic Accelerated Facility Enhancement ("District SAFE") is Washington Gas' third modernization program in D.C. and is focused on long-term safety and reliability.
- AltaGas continued to advance key Midstream growth projects during the third quarter. Strong progress was made on REEF's in-water piling work for the jetty and the site's overburden activities, while compression, refrigeration and vessel fabrication work is advancing in controlled operating environments at offsite manufacturing facilities. At Pipestone II, construction is progressing to plan, including completion of the two acid gas injection wells and the majority of the gas gathering system, while compression, processing and fabrication work is progressing at offsite manufacturing facilities. Both midstream growth projects remain on schedule and on budget with 50 percent of REEF and 92 percent of Pipestone II project costs either incurred or under fixed price contracts.
- The MVP in the Appalachian Basin saw its 20 year firm service contracts with investment grade counterparties coming into effect July 1, 2024. The 2.0 Bcf/d pipeline is fully subscribed and is expandable by an additional 475 MMcf/d through low cost compression with extension into North Carolina through the Southgate project.
- AltaGas had two financings in the third quarter of 2024, including:
    - On July 9, 2024, AltaGas issued $250 million of senior unsecured medium-term notes with a 5.60 percent coupon, due on March 14, 2054. The net proceeds were used to pay down amounts drawn on the syndicated credit facility, which was incurred when the Company repaid its term loan on June 28, 2024.
    - On September 23, 2024, AltaGas issued US$900 million of 7.20 percent Fixed-to-Fixed Rate Junior Subordinated Hybrid Notes, due 2054 (the "Hybrid Notes"). The Hybrid Notes are callable at the first reset date of October 15, 2034. AltaGas also executed a cross-currency swap arrangement to convert the underlying proceeds and interest costs into Canadian dollars, resulting in an effective annual interest rate of 6.90 percent over the initial ten year period of the notes. AltaGas intends to use the net proceeds of the Hybrid Notes to reduce the Company's outstanding senior notes and bank debt, and will receive 50 percent equity treatment for credit rating metrics.
- On September 30, 2024, AltaGas announced the conversion of the Cumulative Redeemable Floating Rate Preferred Shares, Series H (the "Series H Shares") into Cumulative Redeemable Five-Year Rate Reset Preferred Shares, Series G (the "Series G Shares") on a one for one basis and the subsequent cancellation and de-listing of the Series H Shares from the Toronto Stock Exchange ("TSX").
- Following a strong third quarter, AltaGas anticipates delivering fiscal 2024 results that will include normalized EBITDA in the upper end of the guidance range of $1,675 million to $1,775 million while normalized EPS is expected to be around the midpoint of the guidance range of $2.05 to $2.25.

Highlights Subsequent to Quarter End

- On October 1, 2024, Washington Gas executed a note purchase agreement to issue US$200 million in private placement notes. US$100 million of these notes were issued on October 1, 2024 at 5.40 percent with a maturity date of October 1, 2054 and the remaining US$100 million will be issued on April 1, 2025 at 4.84 percent with a maturity date of April 1, 2035. The proceeds will be used for general corporate purposes.

Consolidated Financial Review

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions, except effective income tax rates)	**2024**	2023	**2024**	2023
Revenue	**2,759**	3,030	**9,189**	9,709
Normalized EBITDA (1)	**294**	252	**1,249**	1,073
Income (loss) before income taxes	**20**	(51)	**515**	751
Net income (loss) applicable to common shares	**9**	(50)	**375**	528
Normalized net income (1) (2)	**42**	23	**421**	322
Total assets	**24,748**	22,183	**24,748**	22,183
Total long-term liabilities	**13,467**	11,073	**13,467**	11,073
Invested capital (1)	**374**	257	**936**	656
Cash from (used in) investing activities	**(393)**	(243)	**(973)**	395
Dividends declared (3)	**89**	79	**265**	237
Cash from operations	**21**	3	**1,030**	967
Normalized funds from operations (1)	**105**	142	**795**	752
Normalized effective income tax rate (%) (1) (2)	**20.6**	22.7	**22.2**	20.6
Effective income tax rate (%) (4)	**16.7**	23.2	**22.6**	25.3

	Three Months Ended September 30		Nine Months Ended September 30	
($ per share, except shares outstanding)	**2024**	2023	**2024**	2023
Net income (loss) per common share - basic	**0.03**	(0.18)	**1.26**	1.87
Net income (loss) per common share - diluted	**0.03**	(0.18)	**1.26**	1.86
Normalized net income - basic (1) (2)	**0.14**	0.08	**1.42**	1.14
Normalized net income - diluted (1) (2)	**0.14**	0.08	**1.41**	1.14
Dividends declared (3)	**0.30**	0.28	**0.89**	0.84
Cash from operations	**0.07**	0.01	**3.48**	3.43
Normalized funds from operations (1)	**0.35**	0.50	**2.69**	2.67
Shares outstanding - basic (millions)				
During the period (5)	**298**	282	**296**	282
End of period	**298**	282	**298**	282

(1) Non-GAAP financial measure or non-GAAP financial ratio; see discussion in *Non-GAAP Financial Measures* section of this MD&A.

(2) In the fourth quarter of 2023, AltaGas changed its non-GAAP policy to exclude the impact of unrealized foreign exchange losses (gains) on intercompany balances between Canadian and U.S. entities. Prior periods have been restated to reflect this change. Please refer to the *Non-GAAP Financial Measures* section of this MD&A for additional details.

(3) Dividends declared per common share per quarter: $0.28 per share beginning March 2023, increased to $0.2975 per share effective March 2024.

(4) The decrease in the effective income tax rate for the three months ended September 30, 2024 is due to the composition of income before income taxes.

(5) Weighted average.

Results of Operations by Reporting Segment

Normalized EBITDA [1]	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2024**	2023	**2024**	2023
Utilities	**$ 117**	$ 71	**$ 676**	$ 575
Midstream	**181**	185	**603**	502
Sub-total: Operating Segments	**$ 298**	$ 256	**$ 1,279**	$ 1,077
Corporate/Other	**(4)**	(4)	**(30)**	(4)
	$ 294	$ 252	**$ 1,249**	$ 1,073

(1) Non-GAAP financial measure; see discussion in Non-GAAP Financial Measures section of this MD&A.

Income (Loss) Before Income Taxes	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2024**	2023	**2024**	2023
Utilities	**$ 24**	$ (16)	**$ 441**	$ 679
Midstream	**123**	61	**465**	381
Sub-total: Operating Segments	**$ 147**	$ 45	**$ 906**	$ 1,060
Corporate/Other	**(127)**	(96)	**(391)**	(309)
	$ 20	$ (51)	**$ 515**	$ 751

Revenue	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2024**	2023	**2024**	2023
Utilities	**$ 839**	$ 767	**$ 3,241**	$ 3,539
Midstream	**1,887**	2,237	**5,881**	6,098
Sub-total: Operating Segments	**$ 2,726**	$ 3,004	**$ 9,122**	$ 9,637
Corporate/Other	**33**	26	**67**	72
	$ 2,759	$ 3,030	**$ 9,189**	$ 9,709

Three Months Ended September 30

Normalized EBITDA for the third quarter of 2024 was $294 million, compared to $252 million for the same quarter of 2023. The increase was largely driven by strong results from the Utilities segment, as well as record global export volumes in the Midstream segment.

In the Utilities segment, normalized EBITDA was mainly impacted by the gain on partial settlement of the WGL Holdings, Inc. ("WGL") post-retirement benefit pension plan, partially offset by lower contributions from WGL's retail marketing business.

In the Midstream segment, normalized EBITDA was mainly impacted by higher volumes and margins from the global exports business and contributions from the recently acquired Pipestone Assets, which were more than offset by higher operating and administrative expenses and lower equity earnings at MVP due to the absence of AFUDC recorded in the third quarter of 2023.

In the Corporate/Other segment, normalized EBITDA was mainly impacted by higher contributions from Blythe, offset by higher expenses related to employee incentive plans, primarily as a result of the increasing share price in the third quarter of 2024.

Income before income taxes for the third quarter of 2024 was $20 million, compared to loss before income taxes of $51 million for the same quarter of 2023. The increase was mainly due to lower unrealized losses on risk management contracts, the same previously referenced factors impacting normalized EBITDA, proceeds received from an escrow account related to the 2019 disposition of AltaGas' investment in Meade Pipeline Co. LLC ("Meade"), which held WGL Midstream's indirect, non-operating interest in Central Penn pipeline ("Central Penn"), and lower transaction costs related to acquisitions and dispositions, partially offset by higher transition and restructuring costs, higher interest expense, higher depreciation and amortization expense, and lower foreign exchange gains. Net income applicable to common shares for the third quarter of 2024 was $9 million ($0.03 per share), compared to net loss applicable to common shares of $50 million ($0.18 per share) for the same quarter of 2023. The increase was mainly due to the same previously referenced factors impacting income before income taxes and lower preferred share dividends, partially offset by lower income tax recovery.

Normalized funds from operations for the third quarter of 2024 was $105 million ($0.35 per share), compared to $142 million ($0.50 per share) for the same quarter of 2023. The decrease was mainly due to the impact of non-cash items included in normalized EBITDA, higher normalized current income tax expense, higher interest expense, and foreign exchange losses compared to foreign exchange gains in the third quarter of 2023, partially offset by the same previously referenced factors impacting normalized EBITDA.

Cash from operations in the third quarter of 2024 was $21 million ($0.07 per share), compared to $3 million ($0.01 per share) for the same quarter of 2023. The increase was mainly due to favourable variances in the net change in operating assets and liabilities, primarily as a result of fluctuations in commodity prices and sales volumes, partially offset by lower net income after taxes (after adjusting for non-cash items). Please refer to the *Liquidity* section of this MD&A for further details on the variance in cash from operations.

Interest expense for the third quarter of 2024 was $110 million, compared to $95 million for the same quarter of 2023. The increase was mainly due to higher average debt balances, incremental hybrid interest costs due to the issuance of additional Hybrid Notes in the third quarter of 2024 as well as the fourth quarter of 2023, higher average interest rates, and a higher average Canadian/U.S. dollar exchange rate, partially offset by higher capitalized interest. Interest expense recorded on the Hybrid Notes in the third quarter of 2024 was $15 million, compared to $9 million for the same quarter of 2023.

AltaGas recorded an income tax expense of $3 million for the third quarter of 2024, compared to income tax recovery of $12 million for the same quarter of 2023. The increase in income tax expense was mainly due to higher income before income taxes.

Normalized net income was $42 million ($0.14 per share) for the third quarter of 2024, compared to $23 million ($0.08 per share) for the same quarter of 2023. The increase was mainly due to the same previously referenced factors impacting normalized EBITDA and lower preferred share dividends, partially offset by higher interest expense, higher depreciation expense, and higher normalized income tax expense. Please refer to the *Non-GAAP Financial Measures* section of this MD&A for further details on normalization adjustments.

Nine Months Ended September 30

Normalized EBITDA for the first nine months of 2024 was $1,249 million, compared to $1,073 million for the same period in 2023. The largest positive impact was from the Midstream segment, followed by the Utilities segment.

In the Midstream segment, normalized EBITDA was mainly impacted by higher profitability from the global exports business and higher contributions from the fractionation and liquids handling business, partially offset by the absence of the favourable resolution of certain commercial disputes and contingencies in the first half of 2023.

In the Utilities segment, normalized EBITDA was mainly impacted by the partial settlement of WGL's post-retirement benefit pension plan, higher contributions from WGL's retail marketing business, and higher revenue from ARP investments, partially offset by the impact of the Alaska Utilities Disposition in the first quarter of 2023, the absence of the gain resulting from the partial debt defeasance associated with the Alaska Utilities Disposition in the first quarter of 2023, and decreased asset optimization activities at Washington Gas.

In the Corporate/Other segment, normalized EBITDA was mainly impacted by higher expenses related to employee incentive plans, primarily as a result of the increasing share price in the first nine months of 2024, as well as lower contributions from Blythe primarily due to a planned turnaround that was completed in the first quarter of 2024.

Income before income taxes for the first nine months of 2024 was $515 million, compared to $751 million for the same period in 2023. The decrease was mainly due to the absence of the gain on the Alaska Utilities Disposition as well as additional proceeds received in the first quarter of 2023 for the favourable settlement of contract contingencies related to the sale of the Goleta energy storage development in California ("Goleta") in 2022, higher transition and restructuring costs, higher interest expense, unrealized losses on risk management contracts compared to unrealized gains in the same period in 2023, and higher depreciation and amortization expense, partially offset by the same previously referenced factors impacting normalized EBITDA, lower transaction costs related to acquisitions and dispositions, and lower accretion expense. Net income applicable to common shares for the first nine months of 2024 was $375 million ($1.26 per share), compared to $528 million ($1.87 per share) for the same period in 2023. The decrease was mainly due to the same previously referenced factors impacting income before income taxes, partially offset by lower income tax expense and lower preferred share dividends.

Normalized funds from operations for the first nine months of 2024 was $795 million ($2.69 per share), compared to $752 million ($2.67 per share) for the same period in 2023. The increase was mainly due to the same previously referenced factors impacting normalized EBITDA, partially offset by the impact of non-cash items included in normalized EBITDA, higher normalized current income tax expense, and higher interest expense.

Cash from operations for the first nine months of 2024 was $1,030 million ($3.48 per share), compared to $967 million ($3.43 per share) for the same period in 2023. The increase was mainly due to higher net income after taxes (after adjusting for non-cash items), partially offset by unfavourable variances in the net change in operating assets and liabilities, primarily as a result of fluctuations in commodity prices and sales volumes. Please refer to the *Liquidity* section of this MD&A for further details on the variance in cash from operations.

Interest expense for the first nine months of 2024 was $327 million, compared to $293 million for the same period in 2023. The increase was mainly due to higher average debt balances, incremental hybrid interest costs due to the issuance of additional Hybrid Notes in the third quarter of 2024 as well as the fourth quarter of 2023, higher average interest rates, and a higher average Canadian/U.S. dollar exchange rate, partially offset by higher capitalized interest. For the nine months ended September 30, 2024, AltaGas recorded total interest expense of $41 million on the Hybrid Notes compared to $26 million for the same period in 2023.

AltaGas recorded income tax expense of $116 million for the first nine months of 2024, compared to $190 million in the same period in 2023. The decrease in tax expense was mainly due to lower income before income taxes and the tax impact of the Alaska Utilities Disposition that occurred in the first quarter of 2023.

Normalized net income was $421 million ($1.42 per share) for the first nine months of 2024, compared to $322 million ($1.14 per share) for the same period in 2023. The increase was mainly due to the same previously referenced factors impacting normalized EBITDA and lower preferred share dividends, partially offset by higher normalized income tax expense, higher interest expense, and higher depreciation expense. Please refer to the *Non-GAAP Financial Measures* section of this MD&A for further details on normalization adjustments.

2024 Outlook

In 2024, AltaGas expects to achieve normalized EBITDA of approximately $1.675 to $1.775 billion compared to actual normalized EBITDA of $1.58 billion in 2023, and normalized earnings per share of approximately $2.05 to $2.25 compared to actual normalized earnings per share of $1.90 and GAAP net income per share of $2.27 in 2023. For the year ended December 31, 2023, income before income taxes and net income applicable to common shares were $912 million and $641 million, respectively.

The Utilities segment is expected to contribute approximately 55 percent of normalized EBITDA in 2024, with year-over-year expected growth primarily driven by positive contribution from the partial settlement of WGL's post-retirement benefit pension plan, continued rate base growth through ongoing capital investments in asset modernization programs on behalf of AltaGas' customers, the D.C. rate case, and new customer growth, partially offset by the lost contribution from the Alaskan Utilities due to the Alaska Utilities Disposition in the first quarter of 2023 and decreased asset optimization activities at Washington Gas. The Midstream segment is expected to contribute approximately 45 percent of normalized EBITDA, with year-over-year expected growth driven primarily by strong expected global export volumes and margins, higher NGL marketing margins, higher utilization at the Company's Northeastern B.C. facilities, and contributions from the Pipestone Assets added at the end of 2023, partially offset by the absence of the favourable resolution of certain commercial disputes in 2023, lower earnings at the extraction facilities, and lower co-generation revenue at the Harmattan gas processing facility and extraction plant.

The expected variance in normalized earnings per share from $1.90 in 2023 to approximately $2.05 to $2.25 in 2024 is expected to be primarily due to the same factors impacting normalized EBITDA and lower expected preferred share dividends, partially offset by higher expected interest expense, higher depreciation and amortization expense, and higher normalized income tax expense.

The forecasted normalized EBITDA and earnings per share include assumptions around the Canadian/U.S. dollar exchange rate. Within each segment, the performance of the underlying businesses has the potential to vary. Any variance from AltaGas' current assumptions could impact the forecasted normalized EBITDA and normalized earnings per share. For further discussion of the risks impacting AltaGas please refer to the *Risk Factors* section of AltaGas' 2023 Annual Information Form, which is available on SEDAR+ at www.sedarplus.ca.

AltaGas continues to focus on de-risking its business and managing direct commodity price exposure to drive predictable and durable results. While the Company does have exposure, it plans to maintain an active hedging program that proactively hedges commodity price and spread risk to mitigate the impact of fluctuations in margins and cash flows. For the remainder of 2024, AltaGas has hedged materially all of its expected Baltic freight exposure through time charters, financial hedges, and tolled volumes, in addition to the hedges in the following table:

Midstream Hedge Program	Remainder of 2024
Global Exports volumes hedged (%) (1)	87
Average propane/butane FEI to North America hedge (US$/Bbl) (2) (3)	18.06
Fractionation volumes hedged (%) (3)	80
Frac spread hedge rate (US$/Bbl) (3)	24.54

(1) Approximate expected volumes hedged. Includes contracted tolling volumes and financial hedges. Based on AltaGas' internally assumed export volumes. AltaGas is hedged at a higher percentage for firmly committed volumes.

(2) Does not include physical differential to FSK for C3 volumes. Butane is hedged as a percentage of WTI.

(3) Approximate average for the period.

Sensitivity Analysis

AltaGas' financial performance is affected by factors such as changes in commodity prices, exchange rates, discount rates, and weather. The following table illustrates the approximate effect of these key variables on AltaGas' expected normalized annual results for 2024:

Factor	Increase or decrease	Approximate impact on normalized annual results *($ millions)*
Degree day variance from normal - Utilities (1) (2)	5 percent	8
Change in Canadian dollar per U.S. dollar exchange rate (3) (4)	0.05	3
Propane and butane FEI to North America spreads (1) (5)	US$1/Bbl	1

(1) Represents impact on annual normalized EBITDA.
(2) Degree days – Utilities relate to SEMCO Energy Gas Company ("SEMCO") and D.C. service areas. Degree days are a measure of coldness determined daily as the numbers of degrees the average temperature during the day in question is below 65 degrees Fahrenheit. Degree days for a particular period are the average of degree days during the prior 15 years for SEMCO and during the prior 30 years for Washington Gas.
(3) Represents impact on annual normalized net income in the Utilities segment.
(4) The sensitivity is net of hedges on U.S. denominated earnings currently in place. Refer to the *Risk Management* section of this MD&A for more details.
(5) The sensitivity is net of hedges currently in place. The impact on normalized EBITDA due to changes in the spread will vary and is being managed through an active hedging program.

Capital Expenditures

AltaGas is maintaining a disciplined, equity self-funded capital program, and currently expects to deploy the following amount of invested capital in 2024:

	2024 (Forecasted)	2023 (Actuals)
Invested Capital	**$1.3 billion**	$946 million
Split by segment:		
Utilities	**53 %**	79 %
Midstream	**43 %**	20 %
Corporate	**4 %**	1 %

In 2024, AltaGas' capital expenditures for the Utilities segment are expected to focus primarily on safety and reliability programs including system betterment, asset modernization and pipeline replacement programs, and new customer additions. In the Midstream segment, capital expenditures are anticipated to primarily relate to new project development including REEF and Pipestone Phase II, maintenance and administrative capital, optimization of existing assets, and environmental initiatives. The Corporation continues to focus on capital efficient organic growth and disciplined capital allocation while improving balance sheet strength and flexibility.

AltaGas' 2024 committed capital program is expected to be funded through internally-generated cash flow, opportunistic asset sales, and senior debt.

Please refer to the *Net Invested Capital* and *Non-GAAP Financial Measures* sections of this MD&A for additional information on the components of AltaGas' invested capital.

Growth Capital Project Updates

The following table summarizes the status of AltaGas' significant growth projects:

Project	AltaGas' Ownership Interest	Estimated Cost (1)	Project Description and Status	Expected In-Service Date
Midstream Projects				
Pipestone Phase II	100%	$425 million - $450 million	Pipestone Phase II is a 100 MMcf/d sour deep-cut natural gas processing facility with 20,000 Bbls/d of liquids handling capabilities. The project reached a positive FID in December 2023 and is 100 percent contracted under long-term take-or-pay agreements. The project will be adjacent to Pipestone Phase I, which AltaGas acquired in December 2023, and is being constructed on a fixed price turnkey basis for the majority of the capital costs. Construction is underway and when complete, will deliver critical gas processing and liquids handling capacity in the Pipestone region of Alberta, which is one of the fastest growing liquids-rich natural gas developments in Canada.	2025 Year-end
REEF	50%	$675 million	REEF is a proposed large-scale LPG and bulk liquids export terminal with supporting marine infrastructure that is to be constructed on Ridley Island, British Columbia. The project is being developed by AltaGas and Vopak Development Canada Holdings Inc. ("Vopak") and will be located adjacent to the partners' existing RIPET facility. On May 29, 2024, a positive FID for Phase 1 was announced on the project. AltaGas will hold a 50 percent working interest in REEF and will be the project operator with Vopak holding the other 50 percent interest. All major gating items including front-end engineering design ("FEED") and a detailed Class III capital estimate have been completed. Site clearing work is complete, in water works has commenced, earthworks contractor has mobilized and work is progressing. Phase 1 includes construction of a new deep water marine jetty with significant capacity for potential future phases.	2026 Year-end

Project	AltaGas' Ownership Interest	Estimated Cost [1]	Project Description and Status	Expected In-Service Date
Midstream Projects, continued				
MVP Southgate Project	5%	US$19 million	The MVP Southgate Project is an interstate natural gas pipeline that will extend MVP from southern Virginia into central North Carolina. The project is owned by a consortium with AltaGas owning a 5 percent equity stake. In December 2023, MVP announced it entered into precedent agreements with two counterparties to collectively provide 550,000 Dth per day of firm capacity commitments for 20-year terms with two potential five-year extensions. The precedent agreements contemplate a redesigned project, which would extend 31-miles from the terminus of MVP in Pittsylvania County, Virginia to planned new delivery points in Rockingham County, North Carolina using a 30-inch diameter pipe, substantially fewer water crossings, and would not require a new compressor station. MVP expects to finalize the redesigned project scope after it conducts an open season and executes any additional agreements for firm capacity. The redesigned MVP Southgate Project is expected to cost approximately US$370 million, of which approximately US$19 million will be AltaGas' portion. In the fourth quarter of 2021, AltaGas impaired its equity investment in the MVP Southgate project to a carrying value of $nil as a result of legal and regulatory challenges the project has encountered. Despite the asset write down in the fourth quarter of 2021, AltaGas remains committed to supporting the MVP Southgate project and connecting downstream customers to this critical transportation capacity.	June 2028 with majority of the spend expected in 2027.

Project	AltaGas' Ownership Interest	Estimated Cost (1)	Project Description and Status	Expected In-Service Date
Utilities Projects (2)				
Accelerated Utility Pipe Replacement Programs – ***Washington Gas – District of Columbia***	100%	Estimated US$50 million for the period March 2024 to February 2025. Previous three years totaled US$150 million.	The second phase of Washington Gas' ARP in D.C. was scheduled to end in December 2023. On December 22, 2022, Washington Gas filed an application with the Public Service Commission of the District of Columbia ("PSC of DC") for PROJECTpipes 3, seeking approval of approximately US$672 million for the five-year period from January 1, 2024 to December 31, 2028. On November 6, 2023, Washington Gas filed a request to extend PROJECTpipes 2 through December 31, 2024. On February 23, 2024, the PSC of DC granted Washington Gas' request to extend PROJECTpipes 2 and the surcharge for 12 months, through February 2025, with a surcharge spending limit of US$50 million. The District of Columbia Government ("DCG") filed a Petition for Reconsideration of the order approving the extension of the program, and Washington Gas filed a response requesting denial of DCG's Petition. On September 12, 2024, the PSC of DC held in abeyance 41 projects on the current Project List for PROJECTpipes 2, pending submission of risk assessment scores and explanations as well as final approval for PROJECTpipes 2 extension surcharge recovery. Washington Gas filed the requested information on September 27, 2024. On June 12, 2024, the PSC of DC issued an order dismissing Washington Gas' PROJECTpipes 3 application, and concurrently opened a new docket and directed Washington Gas to file a new and restructured application that comports with DC's climate goals within 45 days of the date of the order, or by July 29, 2024. On July 12, 2024, Washington Gas filed an Application for Reconsideration (which was subsequently denied on August 7, 2024). On July 17, 2024, the DCG filed a motion to extend the time by at least 90 days, for Washington Gas to file its restructured plan, which was granted by the PSC of DC on July 26, 2024. On September 27, 2024, Washington Gas filed its restructured plan, District SAFE, requesting US$215 million for the period from March 1, 2025 through December 31, 2027. On October 24, 2024, the PSC of DC approved the 41 projects on the current Project List that were held in abeyance, amended the procedural schedule, and extended the PROJECTpipes 2 program through April 2025.	Individual assets are placed into service throughout the program and are captured in rate base through rate riders.

Project	AltaGas' Ownership Interest	Estimated Cost (1)	Project Description and Status	Expected In-Service Date
Utilities Projects, continued				
Accelerated Utility Pipe Replacement Programs – **Washington Gas – Maryland**	100%	Estimated US$330 million over the five year period from January 2024 to December 2028, plus additional expenditures for subsequent phases upon approval.	On December 13, 2023, the Public Service Commission of Maryland ("PSC of MD") affirmed a public law judge's proposed order for the third phase of Washington Gas' ARP ("STRIDE 3") in Maryland, with a total five-year spending cap of approximately US$330 million. On January 10, 2024, the PSC of MD issued a memorandum explaining its December 13, 2023 decision. On February 9, 2024, the Maryland Office of People's Counsel ("MD OPC") filed a motion for rehearing with the PSC of MD. Washington Gas filed a response on February 22, 2024. On April 19, 2024, the PSC of MD denied the MD OPC's request for rehearing.	Individual assets are placed into service throughout the program and are captured in rate base through rate riders.
Accelerated Utility Pipe Replacement Programs – ***Washington Gas – Virginia***	100%	Estimated US$878 million over the five year period from January 2023 to December 2027, plus additional expenditures for subsequent phases upon approval.	On May 26, 2022, the Commonwealth of Virginia State Corporation Commission ("SCC of VA") approved Washington Gas' proposed amendment for the 2023 to 2027 SAVE Plan with a total five-year spending cap of approximately US$878 million, which may be exceeded by up to 5 percent.	Individual assets are placed into service throughout the program and are captured in rate base through rate riders.
Accelerated Mains Replacement and Infrastructure Reliability Improvement Programs – ***SEMCO ENERGY – Michigan***	100%	Estimated US$115 million over five year period from 2021 to 2025, as well as incremental expenditures of US$99 million from 2025 to 2027, plus additional expenditures for subsequent phases upon approval.	A MRP was agreed to in SEMCO's last rate case settled in December 2019. The five-year MRP program began in 2021 with a total spend of approximately US$60 million. In addition to the MRP program, SEMCO was also granted an IRIP, which is also a five-year program with a total spend of approximately US$55 million beginning in 2021. On April 1, 2024, SEMCO submitted its MRP and IRIP amendment application, seeking approval from the MPSC to extend its MRP and IRIP programs for approximately US$46 million and US$68 million, respectively, for the period from 2025 to 2027, which includes approximately US$15 million of spend for 2025 approved through the previous program. The order approving the settlement agreement was signed September 26, 2024 by the MPSC.	Individual assets are placed into service throughout the program and are captured in rate base through rate riders.

(1) These amounts are estimates and are subject to change based on various factors. Where appropriate, the amounts reflect AltaGas' share of the various projects.

(2) The utility accelerated replacement programs are long-term projects with multiple phases for which expenditures are approved by the regulators and managed in multi-year increments.

Non-GAAP Financial Measures

This MD&A contains references to certain financial measures used by AltaGas that do not have a standardized meaning prescribed by GAAP and may not be comparable to similar measures presented by other entities. Readers are cautioned that these non-GAAP measures should not be construed as alternatives to other measures of financial performance calculated in accordance with GAAP. The non-GAAP measures and their reconciliation to GAAP financial measures are shown below. These non-GAAP measures provide additional information that management of AltaGas ("Management") believes is meaningful in describing AltaGas' operational performance, liquidity and capacity to fund dividends, capital expenditures, and other investing activities. The specific rationale for, and incremental information associated with, each non-GAAP measure is discussed below.

References to normalized EBITDA, normalized net income, normalized funds from operations, normalized income tax expense, normalized effective income tax rate, net debt, adjusted net debt, adjusted net debt to normalized EBITDA, invested capital, and net invested capital throughout this MD&A have the meanings as set out in this section.

Change in Composition of Non-GAAP Measures

In the fourth quarter of 2023, Management changed the composition of certain of AltaGas' non-GAAP measures such that normalized net income now excludes the impact of unrealized intercompany foreign exchange gains (losses) resulting from intercompany balances between a U.S. subsidiary and a Canadian entity, where the foreign exchange impact in the U.S. subsidiary is recorded through gain (loss) on foreign currency translation in the Consolidated Statements of Comprehensive Income (Loss) and the Canadian entity revaluation is recorded through the foreign exchange gain (loss) line item on the Consolidated Statements of Income (Loss). This change was made as a result of Management's assessment that excluding these intercompany foreign exchange impacts from normalized net income is more representative of the Company's ongoing financial performance. Prior period calculations of the relevant non-GAAP measures have been restated to reflect this change. The following table summarizes the impact of this change on the periods presented in this MD&A:

Increase as result of change	Three Months Ended September 30		Nine Months Ended September 30	
($ millions, except where noted)	**2024**	2023	**2024**	2023
Normalized net income [1]	**$ —**	$ (5)	**$ —**	$ 1
Normalized income tax expense	**$ —**	$ (2)	**$ —**	$ —
Normalized effective tax rate (%)	**— %**	(0.8)%	**— %**	— %

(1) Corresponding per share amounts have also been adjusted.

Normalized EBITDA

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2024**	2023	**2024**	2023
Income (loss) before income taxes (GAAP financial measure)	**$ 20**	$ (51)	**$ 515**	$ 751
Add:				
Depreciation and amortization	**119**	109	**352**	331
Interest expense	**110**	95	**327**	293
EBITDA	**$ 249**	$ 153	**$ 1,194**	$ 1,375
Add (deduct):				
Transaction costs related to acquisitions and dispositions (1)	**2**	10	**9**	31
Unrealized losses (gains) on risk management contracts (2)	**37**	91	**10**	(24)
Gains on sale of assets (3)	**(14)**	—	**(12)**	(319)
Transition and restructuring costs (4)	**17**	1	**49**	6
Wind-up of pension plan (5)	**—**	—	**—**	2
Accretion expenses	**2**	3	**4**	8
Foreign exchange losses (gains) (6)	**1**	(6)	**(5)**	(6)
Normalized EBITDA	**$ 294**	$ 252	**$ 1,249**	$ 1,073

(1) Comprised of transaction costs related to acquisitions and dispositions of assets and/or equity investments in the period. These costs are included in the "cost of sales" and "operating and administrative" line items on the Consolidated Statements of Income (Loss). Transaction costs include expenses, such as legal fees, which are directly attributable to the acquisition or disposition.

(2) Included in the “revenue”, “cost of sales”, and "foreign exchange gains (losses)" line items on the Consolidated Statements of Income (Loss). Please refer to Note 13 of the unaudited condensed interim Consolidated Financial Statements as at and for the three and nine months ended September 30, 2024 for further details regarding AltaGas’ risk management activities.

(3) Included in the “other income” line item on the Consolidated Statements of Income (Loss).

(4) Comprised of transition and restructuring costs (including CEO transition). These costs are included in the "operating and administrative" line item on the Consolidated Statements of Income (Loss).

(5) Relates to the completion of the wind-up of the Canadian defined benefit pension plan in the second quarter of 2023. The associated costs are included in the "other income" line on the Consolidated Statements of Income (Loss).

(6) Excludes unrealized losses (gains) on foreign exchange forward contracts that have been entered into for the purpose of cash management. These losses (gains) are included above in the line "unrealized losses (gains) on risk management contracts".

EBITDA is a measure of AltaGas' operating profitability prior to how business activities are financed, assets are amortized, or earnings are taxed. EBITDA is calculated from the Consolidated Statements of Income (Loss) using income (loss) before income taxes adjusted for pre-tax depreciation and amortization, and interest expense.

AltaGas presents normalized EBITDA as a supplemental measure. Normalized EBITDA is used by Management to enhance the understanding of AltaGas' earnings over periods, as well as for budgeting and compensation related purposes. The metric is frequently used by analysts and investors in the evaluation of entities within the industry as it excludes items that can vary substantially between entities depending on the accounting policies chosen, the book value of assets, and the capital structure.

Normalized Net Income

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2024**	2023	**2024**	2023
Net income (loss) applicable to common shares (GAAP financial measure)	**$ 9**	$ (50)	**$ 375**	$ 528
Add (deduct) after-tax:				
Transaction costs related to acquisitions and dispositions (1)	**1**	7	**7**	22
Unrealized losses (gains) on risk management contracts (2)	**28**	70	**7**	(19)
Gains on sale of assets (3)	**(10)**	—	**(6)**	(217)
Transition and restructuring costs (4)	**13**	1	**37**	5
Wind-up of pension plan (5)	**—**	—	**—**	2
Unrealized foreign exchange losses (gains) on intercompany balances (6)	**1**	(5)	**1**	1
Normalized net income	**$ 42**	$ 23	**$ 421**	$ 322

(1) Comprised of transaction costs related to acquisitions and dispositions of assets and/or equity investments in the period. The pre-tax costs are included in the "cost of sales" and "operating and administrative" line items on the Consolidated Statements of Income (Loss). Transaction costs include expenses, such as legal fees, which are directly attributable to the acquisition or disposition.

(2) The pre-tax amounts are included in the “revenue”, “cost of sales”, and "foreign exchange gains (losses)" line items on the Consolidated Statements of Income (Loss). Please refer to Note 13 of the unaudited condensed interim Consolidated Financial Statements as at and for the three and nine months ended September 30, 2024 for further details regarding AltaGas’ risk management activities.

(3) The pre-tax amounts are included in the “other income” line item on the Consolidated Statements of Income (Loss).

(4) Comprised of transition and restructuring costs (including CEO transition). The pre-tax costs are included in the "operating and administrative" line item on the Consolidated Statements of Income (Loss).

(5) Relates to the completion of the wind-up of the Canadian defined benefit pension plan in the second quarter of 2023. The associated costs are included in the "other income" line on the Consolidated Statements of Income.

(6) Relates to unrealized foreign exchange losses (gains) on intercompany accounts receivable and accounts payable balances between a U.S. subsidiary and a Canadian entity, where the impact to the U.S. subsidiary is recorded through accumulated other comprehensive income as a loss on foreign currency translation, and the impact to the Canadian entity is recorded through the "foreign exchange gains" line item on the Consolidated Statements of Income (Loss). As noted previously in this MD&A, in the fourth quarter of 2023, AltaGas changed its non-GAAP policy to exclude the impact of unrealized foreign exchange losses (gains) on intercompany balances between Canadian and U.S. entities. The amounts presented in this table reflect the restated figures to align with the revised policy.

Normalized net income and normalized net income per share are used by Management to enhance the comparability of AltaGas’ earnings, as these metrics reflect the underlying performance of AltaGas’ business activities.

Normalized Funds from Operations

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2024**	2023	**2024**	2023
Cash from operations (GAAP financial measure)	**$ 21**	$ 3	**$ 1,030**	$ 967
Add (deduct):				
Net change in operating assets and liabilities	**64**	124	**(301)**	(298)
Asset retirement obligations settled	**1**	7	**1**	12
Funds from operations	**$ 86**	$ 134	**$ 730**	$ 681
Add (deduct):				
Transaction costs related to acquisitions and dispositions [1]	**2**	10	**9**	31
Transition and restructuring costs [2]	**17**	1	**49**	6
Current tax expense (recovery) on asset sales [3]	**—**	(3)	**7**	34
Normalized funds from operations	**$ 105**	$ 142	**$ 795**	$ 752

(1) Comprised of transaction costs related to acquisitions and dispositions of assets and/or equity investments in the period. These costs exclude non-cash amounts and are included in the "cost of sales" and "operating and administrative" line items on the Consolidated Statements of Income (Loss). Transaction costs include expenses, such as legal fees, which are directly attributable to the acquisition or disposition.
(2) Comprised of transition and restructuring costs (including CEO transition). The pre-tax costs are included in the "operating and administrative" line item on the Consolidated Statements of Income (Loss).
(3) Included in the "current income tax expense (recovery)" line item on the Consolidated Statements of Income (Loss).

Normalized funds from operations and funds from operations are used to assist Management and investors in analyzing the liquidity of the Corporation. Management uses these measures to understand the ability to generate funds for capital investments, debt repayment, dividend payments, and other investing activities.

Funds from operations and normalized funds from operations as presented should not be viewed as an alternative to cash from operations or other cash flow measures calculated in accordance with GAAP.

Normalized Income Tax Expense

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2024**	2023	**2024**	2023
Income tax expense (recovery) (GAAP financial measure)	**$ 3**	$ (12)	**$ 116**	$ 190
Add (deduct) tax impact of:				
Transaction costs related to acquisitions and dispositions	**1**	3	**2**	8
Unrealized losses (gains) on risk management contracts	**9**	21	**3**	(5)
Gains on sale of assets	**(4)**	—	**(6)**	(102)
Transition and restructuring costs	**4**	—	**12**	1
Unrealized foreign exchange gains on intercompany balances [1]	**—**	(2)	**—**	—
Normalized income tax expense	**$ 13**	$ 10	**$ 127**	$ 92

(1) As noted previously in this MD&A, in the fourth quarter of 2023, AltaGas changed its non-GAAP policy to exclude the impact of unrealized foreign exchange losses (gains) on intercompany balances between Canadian and U.S. entities. The amounts presented in this table reflect the restated figures to align with the revised policy.

The above table provides a reconciliation of normalized income tax expense from the GAAP financial measure, income tax expense (recovery). The reconciling items are comprised of the income tax impacts of normalizing items present in the calculation of normalized net income. For more information on the individual normalizing items, please refer to the normalized net income reconciliation above.

Normalized income tax expense is used by Management to enhance the comparability of the impact of income tax on AltaGas' earnings, as it reflects the underlying performance of AltaGas' business activities, and is presented to provide this perspective to analysts and investors.

Net Debt, Adjusted Net Debt, and Adjusted Net Debt to Normalized EBITDA

Net debt, adjusted net debt, and adjusted net debt to normalized EBITDA are used by the Corporation to monitor its capital structure and assess its capital structure relative to earnings. It is also used as a measure of the Corporation's overall financial strength and is presented to provide this perspective to analysts and investors. Net debt is defined as short-term debt, plus current and long-term portions of long-term debt, current and long-term portions of finance lease liabilities, and Hybrid Notes, less cash and cash equivalents. Adjusted net debt is defined as net debt adjusted for current and long-term portions of finance lease liabilities, Hybrid Notes, and debt associated with acquisitions that occurred in the last half of the fiscal year. Adjusted net debt to normalized EBITDA is calculated by dividing adjusted net debt as defined above by normalized EBITDA for the preceding twelve month period.

($ millions, except adjusted net debt to normalized EBITDA)	**September 30, 2024**	December 31, 2023
Short-term debt	**$ 134**	$ 129
Current portion of long-term debt [1]	**854**	999
Current portion of finance lease liabilities	**22**	11
Long-term debt [2]	**7,358**	7,528
Finance lease liabilities	**122**	120
Subordinated hybrid notes [3]	**1,945**	742
Total debt	**10,435**	9,529
Less: cash and cash equivalents	**(772)**	(95)
Net debt	**$ 9,663**	$ 9,434
Current portion of finance lease liabilities	**(22)**	(11)
Finance lease liabilities	**(122)**	(120)
Subordinated hybrid notes [3]	**(1,945)**	(742)
Debt on Pipestone Acquisition	**—**	(327)
Adjusted net debt	**$ 7,574**	$ 8,234
Adjusted net debt to normalized EBITDA [4]	**4.3**	5.2

(1) Net of debt issuance costs of less than $1 million as at September 30, 2024 (December 31, 2023 - less than $1 million).
(2) Net of debt issuance costs, unamortized premiums, and unamortized discounts of $32 million as at September 30, 2024 (December 31, 2023 - $19 million).
(3) Net of debt issuance costs of $20 million as at September 30, 2024 (December 31, 2023 - $8 million).
(4) Calculated as adjusted net debt at the balance sheet date, divided by normalized EBITDA for the preceding twelve month period.

Invested Capital and Net Invested Capital

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2024**	2023	**2024**	2023
Cash used in (from) investing activities (GAAP financial measure)	**$ 393**	$ 243	**$ 973**	$ (395)
Add (deduct):				
Net change in non-cash capital expenditures [(1)]	**23**	12	**20**	(23)
Contributions from non-controlling interests	**(56)**	—	**(73)**	—
Net invested capital	**$ 360**	$ 255	**$ 920**	$ (418)
Asset dispositions	**—**	1	**2**	1,073
Disposals of equity investments [(2)]	**14**	1	**14**	1
Invested capital	**$ 374**	$ 257	**$ 936**	$ 656

(1) Comprised of non-cash capital expenditures included in the "accounts payable and accrued liabilities" line item on the Consolidated Balance Sheets. Please refer to Note 20 of the unaudited condensed interim Consolidated Financial Statements as at and for the three and nine months ended September 30, 2024 for further details.

(2) Relates to escrow account proceeds received from AltaGas' previous investment in Meade which held WGL Midstream's indirect, non-operating interest in Central Penn. Upon close of the sale in 2019, various escrow accounts were established to provide the purchaser a form of recourse for the settlement of indemnification obligations.

Invested capital is a measure of AltaGas' use of funds for capital expenditure activities. It includes expenditures relating to property, plant, and equipment and intangible assets, capital contributed to long term investments, and contributions from non-controlling interests. Net invested capital is invested capital presented net of proceeds from disposals of assets in the period. Net invested capital is calculated based on the investing activities section in the Consolidated Statements of Cash Flows, adjusted for items including the net change in non-cash capital expenditures and contributions from non-controlling interests. Invested capital and net invested capital are used by Management, investors, and analysts to enhance the understanding of AltaGas' capital expenditures from period to period and provide additional detail on the Company's use of capital.

Supplemental Calculations

Reconciliation of Normalized EBITDA to Normalized Net Income

The below table provides a supplemental reconciliation of normalized EBITDA to normalized net income. Both of these non-GAAP measures have been previously reconciled to the relevant GAAP financial measures in the section above. This supplemental information is provided as additional information to assist analysts and investors in comparing normalized EBITDA to normalized net income and is not intended as a substitute for the reconciliations to the nearest comparable GAAP measures. Readers should not place undue reliance on this supplemental reconciliation.

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2024**	2023	**2024**	2023
Normalized EBITDA	**$ 294**	$ 252	**$ 1,249**	$ 1,073
Add (deduct):				
Depreciation and amortization	**(119)**	(109)	**(352)**	(331)
Interest expense	**(110)**	(95)	**(327)**	(293)
Income tax recovery (expense)	**(3)**	12	**(116)**	(190)
Normalizing items impacting income taxes [(1) (2)]	**(10)**	(22)	**(11)**	97
Accretion expenses	**(2)**	(3)	**(4)**	(8)
Foreign exchange losses (gains)	**(1)**	6	**5**	6
Unrealized foreign exchange losses (gains) on intercompany balances [(2)]	**1**	(7)	**1**	1
Net income applicable to non-controlling interests	**(3)**	(4)	**(11)**	(13)
Preferred share dividends	**(5)**	(7)	**(13)**	(20)
Normalized net income [(2)]	**$ 42**	$ 23	**$ 421**	$ 322

(1) Represents the income tax impact related to the normalizing items included in the calculation of Normalized EBITDA.

(2) As noted previously in this MD&A, in the fourth quarter of 2023, AltaGas changed its non-GAAP policy to exclude the impact of unrealized foreign exchange losses (gains) on intercompany balances between Canadian and U.S. entities. The amounts presented in this table reflect the restated figures to align with the revised policy.

Calculation of Normalized Effective Income Tax Rate

The below table provides a calculation of normalized effective income tax rate from normalized net income and normalized income tax expense. Both of these non-GAAP measures have been previously reconciled to the relevant GAAP measures in the section above. This supplemental calculation is provided as additional information to assist analysts and investors in comparing normalized income tax expense to normalized net income and is not intended as a substitute for the reconciliations to the nearest comparable GAAP measures. Readers should not place undue reliance on this supplemental calculation.

($ millions, except normalized effective income tax rate)	Three Months Ended September 30 2024	2023	Nine Months Ended September 30 2024	2023
Normalized net income [(1)]	**$ 42**	$ 23	**$ 421**	$ 322
Add (deduct):				
Normalized income tax expense [(1) (2)]	**13**	10	**127**	92
Net income applicable to non-controlling interests	**3**	4	**11**	13
Preferred share dividends	**5**	7	**13**	20
Normalized net income before taxes [(1)]	**$ 63**	$ 44	**$ 572**	$ 447
Normalized effective income tax rate (%) [(1) (3)]	**20.6**	22.7	**22.2**	20.6

(1) As noted previously in this MD&A, in the fourth quarter of 2023, AltaGas changed its non-GAAP policy to exclude the impact of unrealized foreign exchange losses (gains) on intercompany balances between Canadian and U.S. entities. The amounts presented in this table reflect the restated figures to align with the revised policy.

(2) Calculated in the section above.

(3) Calculated as normalized income tax expense divided by normalized net income before taxes.

Utilities

Operating Statistics

	Three Months Ended September 30 2024	2023	Nine Months Ended September 30 2024	2023
Natural gas deliveries - end-use (Bcf) [(1)]	**8.9**	8.5	**77.9**	85.2
Natural gas deliveries - transportation (Bcf) [(1)]	**20.7**	19.9	**75.9**	77.5
Service sites (thousands) [(2)]	**1,560**	1,553	**1,560**	1,553
Degree day variance from normal - SEMCO Gas (Michigan) (%) [(3)]	**(57.4)**	(19.4)	**(18.6)**	(11.0)
Degree day variance from normal - Washington Gas (D.C.) (%) [(3) (4) (5)]	**(100.0)**	—	**(18.1)**	(22.7)
Retail energy marketing - gas sales volumes (Mmcf)	**8,179**	8,550	**41,653**	39,575
Retail energy marketing - electricity sales volumes (GWh)	**4,344**	4,134	**11,600**	10,821

(1) Bcf is one billion cubic feet.

(2) Service sites reflect all of the service sites of the utilities, including transportation and non-regulated business lines.

(3) A degree day is a measure of coldness determined daily as the number of degrees the average temperature during the day in question is below 65 degrees Fahrenheit. Degree days for a particular period are determined by adding the degree days incurred during each day of the period. Normal degree days for a particular period are the average of degree days during the prior 15 years for SEMCO Gas and during the prior 30 years for Washington Gas.

(4) In certain of Washington Gas' jurisdictions (Virginia and Maryland) there are billing mechanisms in place which are designed to eliminate the effects of variance in customer usage caused by weather and other factors such as conservation. In the District of Columbia, there is no weather normalization billing mechanism nor does Washington Gas hedge to offset the effects of weather. As a result, colder or warmer weather will result in variances to financial results.

(5) The -100 percent degree day variance for Washington Gas in the third quarter of 2024 is a result of there being 12 normal degree days in the third quarter, compared to nil actual degree days. Given that the normal degree days in the third quarter are so low compared to other quarters, any change causes a large variance when shown as a percentage.

Three Months Ended September 30

Normalized EBITDA in the Utilities segment was $117 million in the third quarter of 2024, compared to $71 million in the same quarter of 2023. The increase in normalized EBITDA was mainly due to the partial settlement of WGL's post-retirement benefit pension plan and higher revenue from ARP spend, partially offset by lower contributions from WGL's retail marketing business and decreased asset optimization activities at Washington Gas.

The Utilities segment income before income taxes was $24 million in the third quarter of 2024, compared to a loss before income taxes of $16 million in the same quarter of 2023. The increase was mainly due to the same previously referenced factors impacting normalized EBITDA, partially offset by higher transition and restructuring costs and higher depreciation expense.

Nine Months Ended September 30

The Utilities segment reported normalized EBITDA of $676 million in the first nine months of 2024, compared to $575 million in the same period in 2023. The increase in normalized EBITDA was mainly due to the partial settlement of WGL's post-retirement benefit pension plan, higher contributions from WGL's retail marketing business, higher revenue from ARP spend, the impact of the 2022 D.C. rate case, the impact of the higher foreign exchange rate and realized foreign exchange hedge gains, customer growth, lower operating and administrative expenses, and colder weather in D.C. These factors were partially offset by the impact of the Alaska Utilities Disposition in the first quarter of 2023, the absence of the gain resulting from the partial debt defeasance associated with the Alaska Utilities Disposition in the first quarter of 2023, decreased asset optimization activities at Washington Gas, and warmer weather in Michigan.

The Utilities segment income before income taxes was $441 million in the first nine months of 2024, compared to $679 million in the same period in 2023. The decrease was primarily due to the absence of the gain on the Alaska Utilities Disposition, higher transition and restructuring costs, and lower unrealized gains on risk management contracts, partially offset by the same previously referenced factors impacting normalized EBITDA and lower transaction costs related to acquisitions and dispositions.

In the first nine months of 2023, the Utilities segment recognized a pre-tax gain on sale of assets of approximately $304 million due to the gain on the Alaska Utilities Disposition.

Utilities Rate Cases

Utility/ Jurisdiction	Date Filed	Request	Status	Expected Timing of Decision
Washington Gas - District of Columbia	April 2022	US$53 million increase in base rates, including US$5 million currently collected through the PROJECTpipes surcharge. Therefore, the incremental amount of the base rate increase requested was approximately US$48 million.	On April 4, 2022, Washington Gas filed an application for authority to increase charges for gas service in D.C. On December 22, 2023, the PSC of DC approved a revenue increase of approximately US$25 million, of which approximately US$5 million is currently collected through the PROJECTpipes 2 surcharge. The new rates went into effect January 19, 2024. Requests for reconsideration of certain limited findings in the Commission's decision were filed by certain parties to the case. On February 22, 2024, the PSC of DC issued an Order asking for input from parties on the parameters for an affiliate cost of service study ("ACOSS"). The Order denied other requests for reconsideration. On March 29, 2024, the Apartment and Office Building Association of Metropolitan ("AOBA") Washington filed recommendation on the structure and content of the ACOSS. On May 15, 2024, Washington Gas filed its ACOSS. On June 5, 2024, the AOBA filed a motion to reject the ACOSS, and Washington Gas filed a response on June 14, 2024. The PSC of DC issued an order on June 28, 2024, which denied AOBA's request to reject the ACOSS and directed the parties to meet within 15 days of the date of the order, to discuss the issues identified in the order. The parties met on July 12, 2024 and a joint report on the meeting was filed on July 26, 2024, indicating that the parties reached agreement on the substance and information that should be included in the ACOSS in a base rate case filing. Washington Gas filed an ACOSS consistent with this agreement when it filed its current D.C. base rate case on August 5, 2024.	Final order received on December 22, 2023.
Washington Gas - District of Columbia	August 2024	US$46 million increase in base rates, including US$12 million currently collected through the PROJECTpipes surcharge. Therefore, the incremental amount of the base rate increase requested was approximately US$34 million.	On August 5, 2024, Washington Gas filed an application for authority to increase existing rates and charges for gas service in the District of Columbia. The requested rates are designed to collect approximately US$257 million in total revenues, which represents an increase in Washington Gas' weather-normalized annual revenues of approximately US$46 million and includes a transfer of approximately US$12 million associated with costs from the natural gas system upgrades previously approved by the Commission and currently paid by customers through the PROJECTpipes monthly surcharge, resulting in a net increase of approximately US$34 million in new revenues. On September 12, 2024, the PSC of DC issued an order granting the filed requests for intervention in the case and directing the parties to meet to develop a joint proposed procedural schedule and a list of issues for Washington Gas to address in supplemental testimony, if any, by September 25, 2024. On September 25, 2024, Washington Gas and the parties filed a Joint Proposed Procedural Schedule with the PSC of DC. The proposed schedule calls for legal briefs to be filed on June 18, 2025, whereupon the case would be before the PSC of DC for decision. On October 9, 2024, the schedule filed by Washington Gas was approved by the PSC of DC with hearings scheduled for May 2025. Washington Gas expects to receive a final order from the PSC of DC in the third quarter of 2025.	Final order expected in the third quarter of 2025.

Other Regulatory Updates

Merger Commitments - District of Columbia

On August 9, 2023, the PSC of DC determined that AltaGas had failed to fulfill Term No. 5 Commitment of the PSC of DC's merger approval order related to the June 2018 merger of AltaGas, WGL, and Washington Gas. On reconsideration, the PSC of DC confirmed, in relevant part, that it had credited AltaGas with causing the development of 2.4 MW of Tier one renewable resources by the July 6, 2023 deadline, and that the Company had breached its Term No. 5 Commitment only for the remaining 7.6 MW. As directed by the PSC of DC, AltaGas, the DCG, and the District of Columbia Office of People's Counsel ("DC OPC") conducted negotiations in good faith to reach agreement on a penalty but were unable to reach agreement. Thereafter, AltaGas confirmed that it will specifically perform its Term No. 5 obligations by continuing to cause the development of the remaining 7.6 MW of solar renewable energy. On March 8, 2024, the PSC of DC issued an order to show cause why the penalty amount should not be the maximum allowed under D.C. Code §34-708 (US$5,000/day). On June 14, 2024, AltaGas and DCG jointly requested that the PSC of DC allow sixty (60) days for the parties to negotiate a settlement in the form of a consent decree or, if no agreement is reached, to file a report on the status of the negotiations. AltaGas and DCG have kept the PSC of DC appraised of the status of the negotiations and, on October 8, 2024, filed a Proposed Consent Decree for PSC of DC approval. As at September 30, 2024, AltaGas believes that the civil penalty is probable, and based upon reasonable estimates, has recorded an accrued liability of approximately US$2.1 million.

Prince William County Biogas Pipeline

On December 4, 2023, Washington Gas filed an application with the SCC of VA seeking approval for a biogas supply investment plan and rate adjustment clause. Washington Gas seeks approval to purchase, own, operate, and maintain an eight-mile pipeline, associated interconnection facilities and other necessary equipment to transport RNG from a biogas production facility located at the Prince William County Landfill. Washington Gas also proposes to purchase a portion of the facilities output, a subset of which will be accompanied by marketable environmental attributes. Washington Gas is seeking recovery of the project costs and RNG costs through a Rider RNG. Evidentiary hearing took place on March 19, 2024 and the Hearing Examiner's Report was issued on April 15, 2024. On May 3, 2024, Washington Gas and the Staff filed comments on the report. On May 30, 2024, the SCC of VA issued a Final Order approving the RNG proposed project with a cost cap of US$28 million. The SCC of VA directed Washington Gas to file an application for approval of a Rider RNG at least 120 days prior to the expected in-service date.

Climate Regulation

In the District of Columbia, DC Law 24-177 requires the Mayor to issue final regulations by December 31, 2026 that requires all new construction or substantial improvements of commercial buildings (buildings with more than three stories) to be constructed to a net-zero-energy standard, which is defined to prohibit on-site fuel combustion. On October 17, 2024, Washington Gas, joined by co-plaintiffs, filed suit in the U.S. District Court for the District of Columbia challenging the legality of D.C. 24-177.

In Montgomery County, Maryland, Bill 13-22 will require regulations that establish all-electric building standards for all new construction (with limited exceptions) by December 31, 2026. On October 17, 2024, Washington Gas, joined by co-plaintiffs, filed suit in the U.S. District Court for the District of Maryland challenging the legality of Montgomery County, Maryland Bill 13-22.

Midstream

Operating Statistics

	Three Months Ended September 30		Nine Months Ended September 30	
	2024	2023	**2024**	2023
LPG export volumes (Bbls/d) (1)	**128,272**	118,213	**122,252**	111,151
Total inlet gas processed (Mmcf/d) (1)	**1,303**	1,182	**1,371**	1,299
Extracted ethane volumes (Bbls/d) (1)	**20,314**	25,501	**20,101**	26,224
Extracted NGL volumes (Bbls/d) (1) (2) (3)	**46,707**	36,070	**47,188**	35,415
Fractionation volumes (Bbls/d) (1) (4)	**43,445**	39,699	**42,665**	40,622
Frac spread - realized ($/Bbl) (1) (5)	**24.70**	23.75	**25.15**	25.06
Frac spread - average spot price ($/Bbl) (1) (6)	**30.39**	21.31	**28.30**	23.54
Propane FEI to Mont Belvieu spread (US$/Bbl) (1) (7)	**13.28**	21.30	**13.95**	18.77
Butane FEI to Mont Belvieu spread (US$/Bbl) (1) (8)	**17.44**	22.07	**15.83**	19.71

(1) Average for the period.
(2) NGL volumes refer to propane, butane and condensate.
(3) Volumes for the nine months ended September 30, 2024 include revised volumes of 48,272 Bbls/d for the first quarter of 2024.
(4) Fractionation volumes include NGL mix volumes processed.
(5) Realized frac spread or NGL margin, expressed in dollars per barrel of NGL, is derived from sales recorded by the segment during the period for frac spread exposed volumes plus the settlement value of frac hedges settled in the period less extraction premiums, divided by the total frac exposed volumes produced during the period.
(6) Average spot frac spread or NGL margin, expressed in dollars per barrel of NGL, is indicative of the average sales price that AltaGas receives for propane, butane and condensate less extraction premiums, before accounting for hedges, divided by the respective frac spread exposed volumes for the period.
(7) Average propane price spread between FEI and Mont Belvieu TET commercial index.
(8) Average butane price spread between FEI and Mont Belvieu TET commercial index.

Three Months Ended September 30

The Midstream segment reported normalized EBITDA of $181 million in the third quarter of 2024 compared to $185 million in the same quarter of 2023. The decrease in normalized EBITDA included higher operating and administrative expenses, lower equity earnings at MVP as the recognition of earnings from MVP's operations which commenced in June 2024 was lower than AFUDC recorded in the third quarter of 2023, and lower power revenue at Harmattan primarily due to lower power prices, partially offset by strong performance from the global exports business as a result of higher volumes and margins, as well as contributions from the recently acquired Pipestone Assets, and higher contributions from the fractionation and liquids handling business due to higher North Pine volumes.

Income before income taxes in the Midstream segment was $123 million in the third quarter of 2024, compared to $61 million in the same quarter of 2023. The increase was mainly due to lower unrealized losses on risk management contracts, gains on sale of assets related to cash proceeds received from an escrow account related to the 2019 disposition of AltaGas' investment in Meade, which held WGL Midstream's indirect, non-operating interest in Central Penn, as well as lower accretion expense, partially offset by higher depreciation expense and the same previously referenced factors impacting normalized EBITDA.

In the third quarter of 2024, the Midstream segment recognized a pre-tax gain on sale of assets of approximately $14 million due to the previously mentioned Meade escrow proceeds.

Nine Months Ended September 30

The Midstream segment reported normalized EBITDA of $603 million in the first nine months of 2024, compared to $502 million in the same period in 2023. The increase in normalized EBITDA was mainly due to strong performance from the global exports business as a result of higher volumes and margins, higher contributions from the fractionation and liquids handling business, contributions from the recently acquired Pipestone assets, higher equity earnings at MVP due to higher AFUDC recorded and the recognition of earnings from MVP's operations which commenced in June 2024, the gain on settlement of an asset retirement obligation, and the absence of wildfire impacts recognized in the second quarter of 2023. These factors were partially offset by the absence of the favourable resolution of certain acquisition related commercial disputes and contingencies in the first half of 2023, higher operating and administrative expenses, lower earnings at the extraction facilities primarily due to the impact of higher re-injection of volumes, lower power revenue at Harmattan due to lower power prices compared to the same period in 2023, and lower sales of GHG credits compared to the same period in 2023.

Income before income taxes in the Midstream segment was $465 million in the first nine months of 2024, compared to $381 million in the first nine months of 2023. The increase was mainly due to the same previously referenced factors impacting normalized EBITDA, higher gains on sale of assets primarily related to the previously mentioned Meade escrow proceeds, lower accretion expense, and lower transaction costs related to acquisitions and dispositions, partially offset by higher depreciation expense and higher unrealized losses on risk management contracts.

In the first nine months of 2024 and 2023, the Midstream segment recognized a pre-tax gain on sale of assets of approximately $14 million and $1 million, respectively, due to the previously mentioned Meade escrow proceeds.

Midstream Hedges

	Three Months Ended September 30		Nine Months Ended September 30	
	2024	2023	**2024**	2023
Frac spread exposed volumes (Bbls/d)	**8,437**	8,346	**9,878**	9,881
NGL volumes hedged (Bbls/d)	**8,406**	7,348	**8,301**	7,326
Average price of NGL volumes hedged ($/Bbl) [(1)]	**36**	36	**36**	36
Average FEI to North American NGL price spread for volumes hedged (US$/Bbl)	**15**	13	**17**	13

(1) Excludes basis differential.

Corporate/Other

Three Months Ended September 30

In the Corporate/Other segment, normalized EBITDA for the third quarter of 2024 was a loss of $4 million, consistent with the same quarter of 2023. The main factors impacting normalized EBITDA were higher contributions from Blythe, offset by higher expenses related to employee incentive plans as a result of the increasing share price in the third quarter of 2024.

Loss before income taxes in the Corporate/Other segment was $127 million in the third quarter of 2024, compared to $96 million in the same quarter of 2023. The higher loss was mainly due to higher interest expense, foreign exchange losses compared to foreign exchange gains in the third quarter of 2023, higher transition and restructuring costs, and the same previously referenced factors impacting normalized EBITDA, partially offset by lower transaction costs related to acquisitions and dispositions.

Nine Months Ended September 30

In the Corporate/Other segment, normalized EBITDA for the first nine months of 2024 was a loss of $30 million, compared to $4 million in the same period in 2023. The decrease in normalized EBITDA was primarily due to higher expenses related to employee incentive plans as a result of the increasing share price in the first nine months of 2024 and lower contributions from Blythe as a result of a planned turnaround in the first quarter of 2024.

Loss before income taxes in the Corporate/Other segment was $391 million in the first nine months of 2024, compared to $309 million in the same period in 2023. The higher loss was mainly due to higher interest expense, the same previously referenced factors impacting normalized EBITDA, the absence of the additional gain in the first quarter of 2023 related to the favourable settlement of outstanding contingencies on the sale of Goleta in 2022, higher transition and restructuring costs, and lower unrealized gains on risk management contracts, partially offset by lower transaction costs related to acquisitions and dispositions.

In the first nine months of 2023, the Corporate/Other segment recognized a pre-tax gain of approximately $11 million on the sale of Goleta in 2022 as a result of a payment received in the first quarter of 2023 for the favourable settlement of outstanding contingencies based on contract outcomes.

Net Invested Capital

Invested capital and net invested capital are non-GAAP financial measures. Please refer to the *Non-GAAP Financial Measures* section of this MD&A for further discussion.

	Three Months Ended September 30, 2024			
($ millions)	**Utilities**	**Midstream**	**Corporate/ Other**	**Total**
Invested capital:				
Property, plant and equipment	$ 187	$ 182	$ 3	$ 372
Intangible assets	—	2	—	2
Invested capital	$ 187	$ 184	$ 3	$ 374
Disposals:				
Equity method investments	—	(14)	—	(14)
Net invested capital	$ 187	$ 170	$ 3	$ 360

			Three Months Ended September 30, 2023	
($ millions)	Utilities	Midstream	Corporate/ Other	Total
Invested capital:				
Property, plant and equipment	$ 204	$ 50	$ 1	$ 255
Intangible assets	—	1	—	1
Long-term investments	—	1	—	1
Invested Capital	204	52	1	257
Disposals:				
Asset dispositions	—	(1)	—	(1)
Equity method investments	—	(1)	—	(1)
Net invested capital	$ 204	$ 50	$ 1	$ 255

During the third quarter of 2024, AltaGas' invested capital was $374 million, compared to $257 million in the same quarter of 2023. The increase in invested capital was primarily due to the higher additions to property, plant, and equipment as a result of higher growth capital spend in the Midstream segment, primarily related to Pipestone Phase II and REEF. This was partially offset by lower ARP spend at Washington Gas. In the third quarters of 2024 and 2023, dispositions of equity method investments related to cash proceeds received from an escrow account related to the 2019 disposition of AltaGas' investment in Meade, which held WGL Midstream's indirect, non-operating interest in Central Penn.

Invested capital in the third quarter of 2024 included maintenance capital of $16 million (2023 - $16 million) in the Midstream segment, which was primarily related to maintenance at Harmattan.

During the third quarter of 2024, AltaGas' cash flow from investing activities was an outflow of $393 million compared to $243 million in the same quarter of 2023. Please refer to the *Non-GAAP Financial Measures* and *Liquidity* sections of this MD&A for further information on AltaGas' cash flow from investing activities.

			Nine Months Ended September 30, 2024	
($ millions)	**Utilities**	**Midstream**	**Corporate/ Other**	**Total**
Invested capital:				
Property, plant and equipment	**$ 544**	**$ 351**	**$ 36**	**$ 931**
Intangible assets	**—**	**4**	**—**	**4**
Long-term investments	**—**	**1**	**—**	**1**
Invested capital	**$ 544**	**$ 356**	**$ 36**	**$ 936**
Disposals:				
Asset dispositions	**—**	**(1)**	**(1)**	**(2)**
Equity method investments	**—**	**(14)**	**—**	**(14)**
Net invested capital	**$ 544**	**$ 341**	**$ 35**	**$ 920**

		Nine Months Ended September 30, 2023		
($ millions)	Utilities	Midstream	Corporate/ Other	Total
Invested capital:				
Property, plant and equipment	$ 554	$ 90	$ 3	$ 647
Intangible assets	—	4	1	5
Long-term investments	—	4	—	4
Invested capital	$ 554	$ 98	$ 4	$ 656
Disposals:				
Asset dispositions	(1,059)	(3)	(11)	(1,073)
Equity method investments	—	(1)	—	(1)
Net invested capital	$ (505)	$ 94	$ (7)	$ (418)

In the first nine months of 2024, AltaGas' invested capital was $936 million, compared to $656 million in the same period in 2023. The increase in invested capital was primarily due to the higher additions to property, plant, and equipment as a result of higher growth capital spend in the Midstream segment, primarily related to Pipestone Phase II and REEF, an increase in planned maintenance capital in the Midstream segment and the Corporate/Other segment, and higher capitalized interest. These factors were partially offset by lower ARP spend at Washington Gas. In the first nine months of 2024 and 2023, dispositions of equity method investments primarily related to the previously mentioned Meade escrow proceeds. In the first nine months of 2023, asset dispositions primarily related to the Alaska Utilities Disposition and additional proceeds received for the favourable settlement of outstanding contingencies on the sale of Goleta in the first quarter of 2022.

Invested capital in the first nine months of 2024 included maintenance capital of $41 million (2023 - $23 million) in the Midstream segment and $31 million (2023 - $2 million) related to the remaining power assets in the Corporate/Other segment. The increase in Midstream maintenance capital in the first nine months of 2024 was primarily related to maintenance at Harmattan and Pipestone Phase I, while the increase in maintenance capital in the Corporate/Other segment was primarily due to a planned turnaround at Blythe.

During the first nine months of 2024, AltaGas' cash flow from investing activities was an outflow of $973 million, compared to an inflow of $395 million in the first nine months of 2023. Please refer to the *Non-GAAP Financial Measures* and *Liquidity* sections of this MD&A for further information on AltaGas' cash flow from investing activities.

Liquidity

As a result of certain commitments made to the PSC of DC, the PSC of MD, and the SCC of VA in respect of the acquisition of WGL Holdings, Inc. (the "WGL Acquisition"), Washington Gas is subject to certain restrictions when paying dividends to AltaGas. However, AltaGas does not expect that this will have an impact on AltaGas' ability to meet its obligations.

In addition, Wrangler SPE LLC and Washington Gas made certain ring fencing commitments to the PSC of DC, the PSC of MD, and the SCC of VA with the intention of removing Washington Gas from the bankruptcy estate of AltaGas and its affiliates, other than Washington Gas and Wrangler SPE LLC (together, the "Ring Fenced Entities"). Because of these ring fencing measures, none of the assets of the Ring Fenced Entities would be available to satisfy the debt or contractual obligations of AltaGas or any non-Ring Fenced Entity Affiliate, including any indebtedness or other contractual obligations of AltaGas, and the Ring Fenced Entities do not bear any liability for indebtedness or other contractual obligations of any non-Ring Fenced Entity, and vice versa.

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2024**	2023	**2024**	2023
Cash from operations	**$ 21**	$ 3	**$ 1,030**	$ 967
Investing activities	**(393)**	(243)	**(973)**	395
Financing activities	**1,097**	218	**618**	(1,374)
Increase (decrease) in cash, cash equivalents, and restricted cash	**$ 725**	$ (22)	**$ 675**	$ (12)

Cash From Operations

Cash from operations increased by $63 million for the nine months ended September 30, 2024 compared to the same period in 2023, primarily due to higher net income after taxes (after adjusting for non-cash items) and favourable variances in the net change in operating assets and liabilities. The majority of the variance in net change in operating assets and liabilities was due to lower cash outflows from regulatory liabilities due to fluctuations in commodity prices and less weather impacts at the Utilities as well as higher cash inflows from risk management assets as a result of realized hedge gains, partially offset by lower cash inflows from accounts receivable and inventory due to fluctuations in commodity prices and sales volumes.

Working Capital

($ millions, except working capital ratio)	**September 30, 2024**	December 31, 2023
Current assets	**$ 3,104**	$ 3,045
Current liabilities	**3,018**	3,413
Working capital (deficiency)	**$ 86**	$ (368)
Working capital ratio [(1)]	**1.03**	0.89

(1) Calculated as current assets divided by current liabilities.

The increase in the working capital ratio was primarily due to increases in cash and cash equivalents and regulatory assets, as well as decreases in accounts payable and accrued liabilities, the current portion of long-term debt, regulatory liabilities, and other current liabilities. This was partially offset by decreases in accounts receivable, inventory, risk management assets, and prepaid expenses and other current assets, as well as increases in risk management liabilities, the current portion of finance lease liabilities, the current portion of operating lease liabilities, and short-term debt. AltaGas' working capital will fluctuate in the normal course of business.

Investing Activities

Cash used in investing activities for the nine months ended September 30, 2024 was $973 million, compared to cash from investing activities of $395 million in the same period in 2023. Investing activities for the nine months ended September 30, 2024 included expenditures of approximately $988 million for property, plant and equipment and intangible assets and approximately $1 million of contributions to equity investments, partially offset by proceeds of approximately $14 million and $2 million from the disposition of equity investments and disposition of assets, respectively. Investing activities for the nine months ended September 30, 2023 included proceeds of approximately $1.1 billion primarily related to the Alaska Utilities Disposition and additional proceeds received for the favourable settlement of outstanding contingencies on the sale of Goleta, partially offset by expenditures of approximately $675 million for property, plant and equipment and intangible assets, as well as approximately $4 million of contributions to equity investments.

Financing Activities

Cash from financing activities for the nine months ended September 30, 2024 was $618 million, compared to cash used in financing activities of approximately $1.4 billion in the same period in 2023. Financing activities for the nine months ended September 30, 2024 were primarily comprised of the issuance of long-term debt (net of debt issuance costs) of approximately $1.2 billion, issuance of subordinated Hybrid Notes (net of debt issuance costs) of approximately $1.2 billion, contributions from non-controlling interests of approximately $73 million, and net proceeds from common shares issued on the exercise of options granted pursuant to AltaGas' share option plan ("Share Options") of approximately $51 million, partially offset by the repayment of long-term debt and finance lease liabilities of approximately $1 billion, net repayments under credit facilities of $628 million, dividends of $278 million, distributions to non-controlling interests of approximately $13 million, and a payment of $9 million related to the settlement of derivative instruments. Financing activities for the nine months ended September 30, 2023 were primarily comprised of net repayments under credit facilities of approximately $1.0 billion, repayment of long-term debt and finance lease liabilities of $338 million, dividends of $257 million, purchase of marketable securities in connection with debt defeasance of $193 million, and distributions to non-controlling interests of $13 million, partially offset by the issuance of long-term debt (net of debt issuance costs) of $398 million and net proceeds from common shares issued on the exercise of Share Options of $5 million.

Capital Resources

AltaGas' objective for managing capital is to maintain its investment grade credit ratings, ensure adequate liquidity, optimize the profitability of its existing assets and grow its energy infrastructure to create long-term value and enhance returns for its investors. AltaGas' capital structure is comprised of shareholders' equity (including non-controlling interests), short-term and long-term debt (including the current portion), finance lease liabilities (including the current portion), and Hybrid Notes, less cash and cash equivalents.

The use of debt or equity funding is based on AltaGas' capital structure, which is determined by considering the norms and risks associated with operations and cash flow stability and sustainability.

As at September 30, 2024, AltaGas' total debt primarily consisted of outstanding medium term notes ("MTNs") of $4.6 billion (December 31, 2023 - $3.9 billion), WGL and Washington Gas MTNs and private placement notes of $3.0 billion (December 31, 2023 - $3.0 billion), reflecting fair value adjustments on acquisition, SEMCO First Mortgage Bonds of $401 million (December 31, 2023 - $393 million), $2.0 billion of Hybrid Notes (December 31, 2023 - $750 million), $40 million drawn under the bank credit facilities (December 31, 2023 - $1.0 billion), and commercial paper outstanding of $377 million for WGL and Washington Gas (December 31, 2023 – $461 million). In addition, AltaGas had $231 million of letters of credit outstanding (December 31, 2023 - $252 million).

As at September 30, 2024, AltaGas' total market capitalization was approximately $10 billion based on approximately 298 million common shares outstanding and a closing trading price of $33.48 per common share.

AltaGas' earnings interest coverage for the rolling twelve months ended September 30, 2024 was 2.4 times (twelve months ended September 30, 2023 - 2.9 times).

Credit Facilities ($ millions)	Borrowing capacity	**Drawn at September 30, 2024**	Drawn at December 31, 2023
AltaGas demand credit facilities [1] [2]	$ 70	**$ —**	$ —
AltaGas revolving credit facilities [1] [2]	2,300	**—**	484
AltaGas term credit facility [3]	—	**—**	450
SEMCO Energy US$150 million credit facilities [1] [2]	202	**40**	86
WGL US$300 million revolving credit facility [1] [2] [4]	405	**108**	199
Washington Gas US$450 million revolving credit facility [1] [2] [4]	607	**269**	261
	$ 3,584	**$ 417**	$ 1,480

(1) Amount drawn at September 30, 2024 converted at the month-end rate of 1 U.S. dollar = 1.3499 Canadian dollar (December 31, 2023 - 1 U.S. dollar = 1.3226 Canadian dollar).
(2) All US$ borrowing capacity was converted at the September 30, 2024 Canadian/U.S. dollar month-end exchange rate.
(3) The term loan was cancelled and repaid in full on June 28, 2024.
(4) Amounts drawn include commercial paper that is supported by the long term facilities. WGL and Washington Gas have the right to request additional borrowings of up to US$100 million with the bank's approval, for a total of US$400 million and US$550 million on their respective facilities.

In addition to the facilities listed above, AltaGas has demand letter of credit facilities of $460 million (December 31, 2023 - $451 million). At September 30, 2024, there were letters of credit for $231 million (December 31, 2023 - $252 million) issued on these facilities and an additional less than $1 million (December 31, 2023 - less than $1 million) issued on the Company's revolving credit facilities.

WGL and Washington Gas use short-term debt in the form of commercial paper or unsecured short-term bank loans to fund seasonal cash requirements. Revolving committed credit facilities are maintained in an amount equal to or greater than the expected maximum commercial paper position.

All of the borrowing facilities have covenants customary for these types of facilities, which must be met at each quarter end. AltaGas and its subsidiaries have been in compliance with all financial covenants each quarter since the establishment of the facilities. AltaGas and its subsidiaries are also in compliance with trust indenture requirements for its MTNs as at September 30, 2024 and December 31, 2023.

The following table summarizes the Corporation's primary financial covenants as defined by the credit facility agreements:

Ratios	Debt covenant requirements	**As at September 30, 2024**
Bank debt-to-capitalization [1] [2]	not greater than 65%	less than 43%
Bank EBITDA-to-interest expense [1] [2]	not less than 2.5x	greater than 4.0x
Bank debt-to-capitalization (SEMCO) [2] [3]	not greater than 60%	less than 40%
Bank EBITDA-to-interest expense (SEMCO) [2] [3]	not less than 2.25x	greater than 7.6x
Bank debt-to-capitalization (WGL) [2] [4]	not greater than 65%	less than 48%
Bank debt-to-capitalization (Washington Gas) [2] [4]	not greater than 65%	less than 49%

(1) Calculated in accordance with the Corporation's $2.3 billion credit facility agreement, which is available on SEDAR+ at www.sedarplus.ca. The covenants are equivalent and applicable to all the Corporation's committed credit facilities.
(2) Estimated, subject to final adjustments.
(3) Bank EBITDA-to-interest expense (SEMCO) and Bank debt-to-capitalization (SEMCO) are calculated based on SEMCO's consolidated financial statements and are calculated similarly to bank debt-to-capitalization and bank EBITDA-to-interest expense.
(4) WGL's bank debt-to-capitalization ratio is calculated based on WGL's consolidated financial statements.

On March 31, 2023, a short form base shelf prospectus for the issuance of certain types of future public debt and/or equity issuances was filed to replace the short form base shelf prospectus dated February 22, 2021. This enables AltaGas to access the Canadian capital markets on a timely basis during the 25-month period that the short form base shelf prospectus remains effective.

Related Party Transactions

In the normal course of business, AltaGas transacts with its subsidiaries, affiliates, and joint ventures. There were no significant changes in the nature of the related party transactions described in Note 30 of the 2023 Annual Consolidated Financial Statements.

Subsidiary Entities

The businesses of AltaGas are operated by the Company and a number of its subsidiaries including, without limitation, AltaGas Services (U.S.) Inc., AltaGas Utility Holdings (U.S.) Inc., WGL Holdings, Inc., Wrangler 1 LLC, Wrangler SPE LLC, Washington Gas Resources Corp., WGL Energy Services, Inc, and SEMCO Holding Corporation; in regard to the Utilities business, Washington Gas Light Company, Hampshire Gas Company, and SEMCO Energy, Inc.; and in regard to the Midstream business, AltaGas Extraction and Transmission Limited Partnership, AltaGas Pipeline Partnership, AltaGas Processing Partnership, AltaGas Northwest Processing Limited Partnership, Harmattan Gas Processing Limited Partnership, Ridley Island LPG Export Limited Partnership, AltaGas Pacific Partnership, AltaGas LPG Limited Partnership, Petrogas Energy Corporation ("Petrogas"), Petrogas Holdings Partnership, and Petrogas, Inc. In the Corporate/Other segment the main subsidiary is AltaGas Power Holdings (U.S.) Inc. SEMCO Energy, Inc. conducts its Michigan natural gas distribution business under the name SEMCO Energy Gas Company.

Risk Management

AltaGas is subject to a variety of risks which could have a material impact on the financial results and operations of the Company. Shareholders and prospective investors should carefully evaluate risk factors noted by the Company before investing in the Company's securities, as each of these risks may negatively affect the trading price of the Company's securities, the amount of dividends paid to shareholders and the ability of the Company to fund its debt obligations, including debt obligations under its outstanding notes and any other debt securities that the Company may issue from time to time. For discussion of the risks and trends that could materially affect the Company's performance please refer to AltaGas' 2023 Annual Information Form, which is available on SEDAR+ at www.sedarplus.ca.

Risk Management Contracts

AltaGas is exposed to various market risks in the normal course of operations that could impact earnings and cash flows. AltaGas enters into physical and financial derivative contracts to manage exposure to fluctuations in commodity prices, foreign exchange rates, and interest rates, as well as to optimize certain owned and managed natural gas assets. These contracts do not eliminate AltaGas' exposure to risk associated with fluctuations in commodity prices or foreign exchange rates. The Board of Directors of AltaGas has established a risk management policy for the Corporation establishing AltaGas’ risk management control framework. Derivative instruments are governed under, and subject to, this policy. As at September 30, 2024 and December 31, 2023, the fair values of the Corporation’s derivatives were as follows:

($ millions)		**September 30, 2024**		December 31, 2023
Natural gas	**$**	**(49)**	$	(46)
Energy exports		**(115)**		(4)
NGL frac spread		**(2)**		1
Power		**(43)**		(75)
Crude oil and NGLs		**5**		4
Foreign exchange		**(32)**		19
Net derivative liability	**$**	**(236)**	$	(101)

AltaGas strives to continuously and systematically de-risk the business in order to drive predictable and durable returns and maximize long-term value for stakeholders. For Midstream, this includes striving to match financial hedges with physical volumes, and for Utilities, this includes purchasing physical gas throughout the year to help shield customers from major cost spikes during peak winter demand. AltaGas may also enter into foreign exchange forward derivatives and cross-currency swaps to manage the risk associated with variations in foreign exchange rates.

Commodity Price Contracts

The average indicative spot NGL frac spread for the nine months ended September 30, 2024 was approximately $28/Bbl (2023 - $24/Bbl), inclusive of basis differentials. The average NGL frac spread realized by AltaGas (based on average spot price and realized hedge price inclusive of basis differentials) for the nine months ended September 30, 2024 was approximately $25/Bbl inclusive of basis differentials (2023 - $25/Bbl).

AltaGas continues to focus on de-risking its business and managing direct commodity price exposure to drive predictable and durable results. While the Company does have exposure, it plans to maintain an active hedging program that proactively hedges commodity price and spread risk to mitigate the impact of fluctuations in margins and cash flows. For the remainder of 2024, AltaGas has hedged:

- Approximately 87 percent of its remaining 2024 expected global export volumes through a combination of tolls and financial hedges, with the average FEI to North American financial hedge price of approximately US$18/Bbl for non-tolled propane and butane volumes.
- Approximately 80 percent of its 2024 expected frac exposed volumes hedged at approximately US$25/Bbl, prior to transportation costs.
- Materially all of AltaGas' expected Baltic freight exposure is protected through time charters, financial hedges, and tolled volumes in 2024.

Foreign Exchange Contracts

The following foreign exchange related contracts were outstanding as at September 30, 2024:

	Duration	Fair Value ($ millions)
Foreign exchange forward contracts		
Forward USD sales (deliverable)	Less than 1 year	Less than $1 million
Forward USD sales (non-deliverable)	Less than 1 year	$ 8
Forward USD sales (non-deliverable)	More than 1 year	$ 7
Cross-currency swaps		
Fixed-to-fixed cross-currency swaps	10 years	$ (47)

In the third quarter of 2024, AltaGas executed cross-currency swaps totaling US$900 million to manage the risk of fluctuating cash flows and earnings associated with the recently issued US$900 million Hybrid Notes as a result of changes in the Canadian/U.S. dollar foreign exchange rates. The cross-currency swaps will convert the U.S. dollar principal and interest payments of these Hybrid Notes into Canadian dollars and apply an effective annual interest rate of 6.90 percent on the converted Canadian principal amount of approximately $1.2 billion. AltaGas has designated the cross-currency swaps as cash flow hedges. Refer to Note 13 of the unaudited condensed interim Consolidated Financial Statements as at and for the nine months ended September 30, 2024 for further details.

The following foreign exchange forward contracts were outstanding as at December 31, 2023:

Foreign exchange forward contract	Duration	Fair Value ($ millions)
Forward USD sales (deliverable)	Less than 1 year	Less than $1 million
Forward USD sales (non-deliverable)	Less than 1 year	$ 10
Forward USD sales (non-deliverable)	More than 1 year	$ 9

The following is a summary of gains (losses) on foreign exchange forward contracts recognized in net income:

	Three Months Ended September 30, 2024	Three Months Ended September 30, 2023	**Nine Months Ended September 30, 2024**	Nine Months Ended September 30, 2023
Objective of foreign exchange forward contract	**Gains (losses)**	Gains (losses)	**Gains (losses)**	Gains (losses)
Cash management [(1)]	**$ —**	$ —	**$ (2)**	$ —
Income statement risk management [(2)]	**$ 18**	$ (1)	**$ (3)**	$ (1)

(1) Recorded in the Consolidated Statements of Income (Loss) under the line item "foreign exchange gains (losses)".
(2) Recorded in the Consolidated Statements of Income (Loss) under the line item "revenue".

Weather Instruments

For the nine months ended September 30, 2024, no pre-tax gains or losses (nine months ended September 30, 2023 - pre-tax loss of $8 million) were recorded related to heating degree day ("HDD") and cooling degree day ("CDD") instruments.

The Effects of Derivative Instruments on the Consolidated Statements of Income (Loss)

The following table presents the unrealized gains (losses) on derivative instruments as recorded in the Corporation's Consolidated Statements of Income (Loss):

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2024**	2023	**2024**	2023
Natural gas	**$ (32)**	$ (4)	**$ 19**	$ 17
Energy exports	**(33)**	(77)	**(38)**	(28)
Crude oil and NGLs	**(2)**	1	**(3)**	11
NGL frac spread	**10**	(17)	**(3)**	3
Power	**1**	7	**19**	22
Foreign exchange	**19**	(1)	**(4)**	(1)
	$ (37)	$ (91)	**$ (10)**	$ 24

Please refer to Note 23 of the 2023 Annual Consolidated Financial Statements and Note 13 of the unaudited condensed interim Consolidated Financial Statements as at and for the three and nine months ended September 30, 2024 for further details regarding AltaGas' risk management activities.

Dividends

AltaGas declares and pays a quarterly dividend to its common shareholders. Dividends on preferred shares are also paid quarterly. Dividends are at the discretion of the Board of Directors and dividend levels are reviewed periodically, giving consideration to the ongoing sustainable cash flow from operating activities, maintenance and growth capital expenditures, and debt repayment requirements of AltaGas.

The following tables summarize AltaGas' dividend declaration history as of September 30, 2024:

Common Share Dividends

Year ended December 31		
($ per common share)	**2024**	2023
First quarter	**$ 0.297500**	$ 0.280000
Second quarter	**0.297500**	0.280000
Third quarter	**0.297500**	0.280000
Fourth quarter	**—**	0.280000
Total	**$ 0.892500**	$ 1.120000

Series A Preferred Share Dividends

Year ended December 31		
($ per preferred share)	**2024**	2023
First quarter	**$ 0.191250**	$ 0.191250
Second quarter	**0.191250**	0.191250
Third quarter	**0.191250**	0.191250
Fourth quarter	**—**	0.191250
Total	**$ 0.573750**	$ 0.765000

Series B Preferred Share Dividends

Year ended December 31		
($ per preferred share)	**2024**	2023
First quarter	**$ 0.478740**	$ 0.418750
Second quarter	**0.474950**	0.450260
Third quarter	**0.473320**	0.455150
Fourth quarter	**—**	0.492580
Total	**$ 1.427010**	$ 1.816740

Series E Preferred Share Dividends (1)

Year ended December 31		
($ per preferred share)	**2024**	2023
First quarter	**$ —**	$ 0.337063
Second quarter	**—**	0.337063
Third quarter	**—**	0.337063
Fourth quarter	**—**	0.337063
Total	**$ —**	$ 1.348252

(1) On December 31, 2023, AltaGas redeemed all of its outstanding Series E Preferred Shares.

Series G Preferred Share Dividends

Year ended December 31		
($ per preferred share)	**2024**	2023
First quarter	**$ 0.265125**	$ 0.265125
Second quarter	**0.265125**	0.265125
Third quarter	**0.265125**	0.265125
Fourth quarter	**—**	0.265125
Total	**$ 0.795375**	$ 1.060500

Series H Preferred Share Dividends (1)

Year ended December 31		
($ per preferred share)	**2024**	2023
First quarter	**$ 0.503610**	$ 0.443404
Second quarter	**0.499820**	0.475190
Third quarter	**0.498460**	0.480350
Fourth quarter	**—**	0.517780
Total	**$ 1.501890**	$ 1.916724

(1) On September 30, 2024, AltaGas converted all of its outstanding Series H Preferred Shares to Series G Preferred Shares.

Critical Accounting Estimates

Since a determination of the value of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of AltaGas' Consolidated Financial Statements requires the use of estimates and assumptions that have been made using careful judgment. AltaGas' significant accounting policies have remained unchanged and are contained in the notes to the 2023 Annual Consolidated Financial Statements. Certain of these policies involve critical accounting estimates as a result of the requirement to make particularly subjective or complex judgments about matters that are inherently uncertain, and because of the likelihood that materially different amounts could be reported under different conditions or using different assumptions. For a full discussion of AltaGas' critical accounting estimates and judgements, refer to Note 2 of the 2023 Annual Consolidated Financial Statements. There have been no material changes to AltaGas' critical estimates and judgements during the nine months ended September 30, 2024.

Refer to Note 2 of the unaudited condensed interim Consolidated Financial Statements as at and for the nine months ended September 30, 2024 for discussion of the adoption of new accounting standards and future changes in accounting principles.

Off-Balance Sheet Arrangements

AltaGas did not enter into any material off-balance sheet arrangements during the nine months ended September 30, 2024. Reference should be made to the audited Consolidated Financial Statements and MD&A as at and for the year ended December 31, 2023 for further information on off-balance sheet arrangements.

Disclosure Controls and Procedures ("DCP") and Internal Control Over Financial Reporting ("ICFR")

Management, including the Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining DCP and ICFR, as those terms are defined in National Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings". The objective of this instrument is to improve the quality, reliability, and transparency of information that is filed or submitted under securities legislation.

Management, including the Chief Executive Officer and the Chief Financial Officer, has designed, or caused to be designed under their supervision, DCP and ICFR to provide reasonable assurance that information required to be disclosed by AltaGas in its annual filings, interim filings, or other reports to be filed or submitted by it under securities legislation is made known to them, is reported on a timely basis, financial reporting is reliable, and financial statements prepared for external purposes are in accordance with U.S. GAAP.

The ICFR has been designed based on the framework established in the 2013 Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

Management has designed the existing framework to result in both a complete and accurate consolidation of related information. During the period covered by this MD&A, other than changes in ICFR related to the Pipestone Acquisition, there were no changes made to AltaGas' ICFR that materially affected, or are reasonably likely to materially affect, its ICFR or DCP.

Limitation on Scope

In accordance with the provisions under National Instrument 52-109, the scope of the evaluation does not include ICFR related to the Pipestone Acquisition, which closed on December 22, 2023. These provisions allow an issuer to exclude a business which was acquired not more than 365 days before the issuer's financial year-end from the scope of its certifications. As such, the controls, policies, and procedures related to the Pipestone Acquisition were excluded from management's evaluation of the effectiveness of AltaGas' ICFR as at September 30, 2024. Summary financial information of the Pipestone Acquisition included in the unaudited condensed interim Consolidated Financial Statements as at and for the nine months ended September 30, 2024 includes total assets of approximately $1.1 billion and revenues of approximately $245 million.

It should be noted that a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues, including instances of fraud, if any, have been detected. The design of any system of controls is also based in part on certain assumptions about the likelihood of future events, and there can be no assurances that any design will succeed in achieving its stated goals under all potential conditions.

Share Information

	As at October 25, 2024
Issued and outstanding	
Common shares	297,792,396
Preferred Shares	
Series A	6,746,679
Series B	1,253,321
Series G	8,000,000
Issued	
Share Options	2,657,632
Share Options exercisable	2,657,632

Summary of Consolidated Results for the Eight Most Recent Quarters [1]

($ millions)	**Q3-24**	Q2-24	Q1-24	Q4-23	Q3-23	Q2-23	Q1-23	Q4-22
Total revenue	**2,759**	2,775	3,655	3,288	3,030	2,631	4,048	3,898
Normalized EBITDA	**294**	295	660	502	252	239	582	454
Net income (loss) applicable to common shares	**9**	(42)	408	113	(50)	133	445	54
($ per share)	**Q3-24**	Q2-24	Q1-24	Q4-23	Q3-23	Q2-23	Q1-23	Q4-22
Net income (loss) per common share								
Basic	**0.03**	(0.14)	1.38	0.40	(0.18)	0.47	1.58	0.19
Diluted	**0.03**	(0.14)	1.37	0.40	(0.18)	0.47	1.57	0.19
Dividends declared	**0.30**	0.30	0.30	0.28	0.28	0.28	0.28	0.27

(1) Amounts may not add due to rounding.

AltaGas' quarter-over-quarter financial results are impacted by seasonality, fluctuations in commodity prices, weather, the Canadian/U.S. dollar exchange rate, planned and unplanned plant outages, timing of in-service dates of new projects, and acquisition and divestiture activities.

Revenue for the Utilities is generally the highest in the first and fourth quarters of any given year as the majority of natural gas demand occurs during the winter heating season, which typically extends from November to March.

Other significant items that impacted quarter-over-quarter revenue during the periods noted include:

- The impact of the Alaska Utilities Disposition in the first quarter of 2023; and
- The impact of the Pipestone Acquisition in the fourth quarter of 2023.

Net income (loss) applicable to common shares is also affected by non-cash items such as deferred income tax, depreciation and amortization expense, accretion expense, provisions on assets, and gains or losses on the sale of assets. In addition, net income (loss) applicable to common shares is also impacted by preferred share dividends and gains or losses on the redemption of preferred shares. For these reasons, the net income (loss) may not necessarily reflect the same trends as revenue. Net income (loss) applicable to common shares during the periods noted was impacted by:

- After-tax transaction costs related to acquisitions and dispositions of approximately $7 million, $27 million, and $1 million incurred in the first nine months of 2024, throughout 2023, and the last quarter of 2022, respectively, primarily due to asset sales and the Pipestone Acquisition;
- After-tax transition and restructuring costs of approximately $37 million and $17 million incurred in the first nine months of 2024 and throughout 2023, respectively;
- Favourable resolution of certain acquisition related commercial disputes and contingencies in the first half of 2023 and in the last quarter of 2022;
- The gain resulting from the partial defeasance of SEMCO's First Mortgage Bonds related to the Alaska Utilities Disposition in the first quarter of 2023;
- The gain on the Alaska Utilities Disposition in the first quarter of 2023;
- The loss on the redemption of the Series E Preferred Shares in the fourth quarter of 2023;
- The gain on partial settlement of WGL's post-retirement benefit pension plan in the third quarter of 2024; and
- The gain on sale of assets related to the Meade escrow proceeds in the third quarter of 2024.

CONSOLIDATED BALANCE SHEETS

(condensed and unaudited)

As at *($ millions)*		**September 30, 2024**		December 31, 2023
ASSETS				
Current assets				
Cash and cash equivalents *(note 20)*	**$**	**772**	$	95
Accounts receivable *(net of credit losses of $26 million) (note 13)*		**1,356**		1,844
Inventory *(note 4)*		**720**		847
Regulatory assets		**77**		58
Risk management assets *(note 13)*		**40**		54
Prepaid expenses and other current assets *(note 20)*		**139**		147
		3,104		3,045
Property, plant and equipment		**13,673**		12,728
Intangible assets		**117**		122
Operating right of use assets		**393**		337
Goodwill *(note 5)*		**5,367**		5,270
Regulatory assets		**322**		329
Risk management assets *(note 13)*		**56**		57
Prepaid post-retirement benefits		**744**		626
Long-term investments and other assets *(net of credit losses of $1 million) (notes 6, 13, and 20)*		**240**		271
Investments accounted for by the equity method *(note 8)*		**732**		686
	$	**24,748**	$	23,471
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current liabilities				
Accounts payable and accrued liabilities	**$**	**1,595**	$	1,863
Short-term debt		**134**		129
Current portion of long-term debt *(notes 9 and 13)*		**854**		999
Customer deposits		**93**		92
Regulatory liabilities		**27**		85
Risk management liabilities *(note 13)*		**158**		97
Current portion of finance lease liabilities *(note 13)*		**22**		11
Operating lease liabilities		**100**		92
Other current liabilities *(note 13)*		**35**		45
		3,018		3,413
Long-term debt *(notes 9 and 13)*		**7,358**		7,528
Asset retirement obligations		**461**		448
Unamortized investment tax credits		**1**		1
Deferred income taxes		**1,646**		1,536
Subordinated hybrid notes *(notes 10 and 13)*		**1,945**		742
Regulatory liabilities		**1,272**		1,274
Risk management liabilities *(note 13)*		**174**		115
Finance lease liabilities *(note 13)*		**122**		120
Operating lease liabilities		**317**		258
Other long-term liabilities		**124**		124
Future employee obligations		**47**		49
	$	**16,485**	$	15,608

As at *($ millions)*		**September 30, 2024**		December 31, 2023
Shareholders' equity				
Common shares, no par values, unlimited shares authorized; 2024 - 297.8 million and 2023 - 294.9 million issued and outstanding *(note 15)*	**$**	**7,177**	$	7,120
Preferred shares *(note 15)*		**391**		391
Contributed surplus		**618**		624
Accumulated deficit		**(707)**		(817)
Accumulated other comprehensive income ("AOCI") *(note 11)*		**544**		395
Total shareholders' equity		**8,023**		7,713
Non-controlling interests		**240**		150
Total equity	**$**	**8,263**	$	7,863
	$	**24,748**	$	23,471

Acquisitions (note 3)
Variable interest entities (note 7)
Commitments, guarantees, and contingencies (note 17)
Seasonality (note 21)
Segmented information (note 22)
Subsequent events (note 23)

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF INCOME (LOSS)

(condensed and unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions except per share amounts)	**2024**	2023	**2024**	2023
REVENUE *(note 12)*	**$ 2,759**	$ 3,030	**$ 9,189**	$ 9,709
EXPENSES				
Cost of sales, exclusive of items shown separately	**2,186**	2,543	**6,856**	7,597
Operating and administrative	**433**	379	**1,326**	1,152
Accretion expenses	**2**	3	**4**	8
Depreciation and amortization	**119**	109	**352**	331
	2,740	3,034	**8,538**	9,088
Income from equity investments *(note 8)*	**16**	21	**45**	32
Other income	**96**	21	**141**	385
Foreign exchange gains (losses)	**(1)**	6	**5**	6
Interest expense	**(110)**	(95)	**(327)**	(293)
Income (loss) before income taxes	**20**	(51)	**515**	751
Income tax expense (recovery)				
Current	**12**	(7)	**44**	32
Deferred	**(9)**	(5)	**72**	158
Net income (loss) after taxes	**17**	(39)	**399**	561
Net income applicable to non-controlling interests	**3**	4	**11**	13
Net income (loss) applicable to controlling interests	**14**	(43)	**388**	548
Preferred share dividends	**(5)**	(7)	**(13)**	(20)
Net income (loss) applicable to common shares	**$ 9**	$ (50)	**$ 375**	$ 528
Net income (loss) per common share *(note 16)*				
Basic	**$ 0.03**	$ (0.18)	**$ 1.26**	$ 1.87
Diluted	**$ 0.03**	$ (0.18)	**$ 1.26**	$ 1.86
Weighted average number of common shares outstanding (millions) *(note 16)*				
Basic	**297.6**	281.7	**296.5**	281.7
Diluted	**298.8**	281.7	**298.0**	283.2

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(condensed and unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2024**	2023	**2024**	2023
Net income (loss) after taxes	**$ 17**	$ (39)	**$ 399**	$ 561
Other comprehensive income (loss), net of taxes				
Gain (loss) on foreign currency translation	**(149)**	215	**210**	(21)
Unrealized gain (loss) on net investment hedge *(note 13)*	**12**	(18)	**(17)**	6
Loss on cash flow hedges *(note 13)*	**(52)**	—	**(61)**	—
Reclassification of losses on cash flow hedges *(note 13)*	**11**	—	**18**	—
Actuarial gains (losses) on pension plans and post-retirement benefit ("PRB") plans	**1**	—	**1**	(1)
Reclassification of gain on partial settlement of PRB plan (*note 18)*	**(2)**	—	**(2)**	—
Reclassification of loss on wind-up of Canadian defined benefit ("DB") pension plan	**—**	—	**—**	2
Total other comprehensive income (loss) ("OCI"), net of taxes	**$ (179)**	$ 197	**$ 149**	$ (14)
Comprehensive income (loss) attributable to controlling interests and non-controlling interests, net of taxes	**$ (162)**	$ 158	**$ 548**	$ 547
Comprehensive income (loss) attributable to:				
Non-controlling interests	**$ 3**	$ 4	**$ 11**	$ 13
Controlling interests	**(165)**	154	**537**	534
	$ (162)	$ 158	**$ 548**	$ 547

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF EQUITY

(condensed and unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2024**	2023	**2024**	2023
Common shares *(note 15)*				
Balance, beginning of period	**$ 7,166**	$ 6,765	**$ 7,120**	$ 6,761
Shares issued for cash on exercise of options	**11**	2	**57**	6
Balance, end of period	**$ 7,177**	$ 6,767	**$ 7,177**	$ 6,767
Preferred shares *(note 15)*				
Balance, beginning of period	**$ 391**	$ 586	**$ 391**	$ 586
Balance, end of period	**$ 391**	$ 586	**$ 391**	$ 586
Contributed surplus				
Balance, beginning of period	**$ 619**	$ 625	**$ 624**	$ 625
Exercise of share options	**(1)**	—	**(6)**	—
Balance, end of period	**$ 618**	$ 625	**$ 618**	$ 625
Accumulated deficit				
Balance, beginning of period	**$ (627)**	$ (722)	**$ (817)**	$ (1,142)
Net income (loss) applicable to controlling interests	**14**	(43)	**388**	548
Common share dividends	**(89)**	(79)	**(265)**	(237)
Preferred share dividends	**(5)**	(7)	**(13)**	(20)
Balance, end of period	**$ (707)**	$ (851)	**$ (707)**	$ (851)
AOCI *(note 11)*				
Balance, beginning of period	**$ 723**	$ 415	**$ 395**	$ 626
Other comprehensive income (loss)	**(179)**	197	**149**	(14)
Balance, end of period	**$ 544**	$ 612	**$ 544**	$ 612
Total shareholders' equity	**$ 8,023**	$ 7,739	**$ 8,023**	$ 7,739
Non-controlling interests				
Balance, beginning of period	**$ 197**	$ 147	**$ 150**	$ 162
Net income applicable to non-controlling interests	**3**	4	**11**	13
Contributions from non-controlling interests to subsidiaries	**44**	2	**92**	29
Distributions by subsidiaries to non-controlling interests	**(4)**	(5)	**(13)**	(13)
Adjustment on disposition of assets	**—**	—	**—**	(43)
Balance, end of period	**$ 240**	$ 148	**$ 240**	$ 148
Total equity	**$ 8,263**	$ 7,887	**$ 8,263**	$ 7,887

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(condensed and unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2024**	2023	**2024**	2023
Cash from operations				
Net income (loss) after taxes	**$ 17**	$ (39)	**$ 399**	$ 561
Items not involving cash:				
Depreciation and amortization	**119**	109	**352**	331
Accretion expenses	**2**	3	**4**	8
Deferred income tax expense (recovery)	**(9)**	(5)	**72**	158
Gains on sale of assets	**(14)**	—	**(12)**	(319)
Gain on debt defeasance	**—**	—	**—**	(14)
Income from equity investments *(note 8)*	**(16)**	(21)	**(45)**	(32)
Unrealized losses (gains) on risk management contracts *(note 13)*	**37**	91	**10**	(24)
Amortization of deferred financing costs	**2**	2	**5**	6
Allowance for credit losses *(note 13)*	**6**	1	**21**	15
Change in pension and other post-retirement benefits	**(76)**	2	**(102)**	4
Other	**14**	(12)	**15**	(23)
Asset retirement obligations settled	**(1)**	(7)	**(1)**	(12)
Distributions from equity investments	**4**	3	**11**	10
Changes in operating assets and liabilities *(note 20)*	**(64)**	(124)	**301**	298
	$ 21	$ 3	**$ 1,030**	$ 967
Investing activities				
Capital expenditures - property, plant and equipment	**(405)**	(242)	**(984)**	(671)
Capital expenditures - intangible assets	**(2)**	(2)	**(4)**	(4)
Contributions to equity investments	**—**	(1)	**(1)**	(4)
Proceeds from disposition of equity investments	**14**	1	**14**	1
Proceeds from disposition of assets, net of transaction costs	**—**	1	**2**	1,073
	$ (393)	$ (243)	**$ (973)**	$ 395
Financing activities				
Issuance of long-term debt, net of debt issuance costs	**240**	1	**1,236**	398
Purchase of marketable securities in connection with debt defeasance	**—**	—	**—**	(193)
Repayment of long-term debt and finance lease liabilities	**(4)**	(4)	**(1,017)**	(338)
Net borrowing (repayment) under credit facilities	**(310)**	311	**(628)**	(976)
Issuance of subordinated hybrid notes, net of debt issuance costs *(note 10)*	**1,203**	—	**1,203**	—
Dividends - common shares	**(89)**	(79)	**(265)**	(237)
Dividends - preferred shares	**(5)**	(7)	**(13)**	(20)
Distributions to non-controlling interests	**(4)**	(5)	**(13)**	(13)
Contributions from non-controlling interests	**56**	—	**73**	—
Net proceeds from shares issued on exercise of options *(note 15)*	**10**	1	**51**	5
Settlement of derivative instruments *(note 13)*	**—**	—	**(9)**	—
	$ 1,097	$ 218	**$ 618**	$ (1,374)
Change in cash, cash equivalents, and restricted cash	**725**	(22)	**675**	(12)
Cash, cash equivalents, and restricted cash, beginning of period	**54**	74	**104**	64
Cash, cash equivalents, and restricted cash, end of period *(note 20)*	**$ 779**	$ 52	**$ 779**	$ 52

See accompanying notes to the Consolidated Financial Statements.

(Tabular amounts and amounts in footnotes to tables are in millions of Canadian dollars unless otherwise indicated.)

1. Organization and Overview of the Business

The businesses of AltaGas are operated by the Company and a number of its subsidiaries including, without limitation, AltaGas Services (U.S.) Inc., AltaGas Utility Holdings (U.S.) Inc., WGL Holdings, Inc. ("WGL"), Wrangler 1 LLC, Wrangler SPE LLC, Washington Gas Resources Corp., WGL Energy Services, Inc. ("WGL Energy Services"), and SEMCO Holding Corporation; in regard to the Utilities business, Washington Gas Light Company ("Washington Gas"), Hampshire Gas Company, and SEMCO Energy, Inc.; and in regard to the Midstream business, AltaGas Extraction and Transmission Limited Partnership, AltaGas Pipeline Partnership, AltaGas Processing Partnership, AltaGas Northwest Processing Limited Partnership, Harmattan Gas Processing Limited Partnership, Ridley Island LPG Export Limited Partnership, AltaGas Pacific Partnership, AltaGas LPG Limited Partnership, Petrogas Energy Corporation ("Petrogas"), Petrogas Holdings Partnership, and Petrogas, Inc. In the Corporate/Other segment the main subsidiary is AltaGas Power Holdings (U.S.) Inc. SEMCO Energy, Inc. conducts its Michigan natural gas distribution business under the name SEMCO Energy Gas Company ("SEMCO").

AltaGas is a leading North American energy infrastructure company that connects customers and markets to affordable and reliable sources of energy. The Company operates a diversified, lower-risk, high-growth energy infrastructure business that is focused on delivering resilient and durable value for its stakeholders.

AltaGas' operating segments include the following:

- Utilities, which owns and operates franchised, cost-of-service, rate regulated natural gas distribution and storage utilities that focus on providing safe, reliable, affordable energy to approximately 1.6 million residential and commercial customers. This includes operating two utilities that operate across four major U.S. jurisdictions with a rate base of approximately US$5.3 billion. The Utilities business also includes other storage facilities and contracts for interstate natural gas transportation and storage services, as well as WGL Energy Services, an affiliated retail energy marketing business, which sells natural gas and electricity directly to residential, commercial, and industrial customers located in Maryland, Virginia, Delaware, Pennsylvania, Ohio, and the District of Columbia ("D.C."); and
- Midstream, which is a leading North American platform that connects customers and markets from wellhead to tidewater. The three pillars of the Midstream business include: 1) global exports, which includes AltaGas' two operational Liquified Petroleum Gas ("LPG") export terminals and one prospective development terminal; 2) natural gas gathering, processing and extraction; and 3) fractionation and liquids handling. AltaGas' Midstream segment also includes its natural gas and natural gas liquids ("NGLs") marketing business, domestic logistics, trucking and rail terminals, and liquid and natural gas storage capability.

The Corporate/Other segment consists of AltaGas' corporate activities and a small portfolio of gas-fired power generation and distribution assets capable of generating 508 MW of power primarily in the state of California.

2. Summary of Significant Accounting Policies

BASIS OF PRESENTATION

These unaudited condensed interim Consolidated Financial Statements have been prepared by Management in accordance with United States Generally Accepted Accounting Principles ("U.S. GAAP"). As a result, these unaudited condensed interim Consolidated Financial Statements do not include all of the information and disclosures required in the annual Consolidated Financial Statements and should be read in conjunction with the Corporation's 2023 annual audited Consolidated Financial Statements prepared in accordance with U.S. GAAP. In Management's opinion, these unaudited condensed interim Consolidated Financial Statements include all adjustments that are of a recurring nature and necessary to present fairly the financial position of the Corporation.

Pursuant to National Instrument 52-107, "Acceptable Accounting Principles and Auditing Standards" ("NI 52-107"), U.S. GAAP reporting is generally permitted by Canadian securities laws for companies subject to reporting obligations under U.S. securities laws. On March 28, 2023, AltaGas filed Form 15 with the Securities and Exchange Commission ("SEC") and as such, is no longer an SEC issuer and can no longer rely on the provisions of NI 52-107. Therefore, AltaGas sought and obtained exemptive relief by the securities regulators in Alberta and Ontario to permit it to prepare its financial statements in accordance with U.S. GAAP. The Alberta Securities Commission exemption will terminate on or after the earlier of January 1, 2027, the date to which AltaGas ceases to have activities subject to rate regulation, or the first day of AltaGas' fiscal year that commences on or following the latter of: a) the effective date prescribed by the IASB for a mandatory rate regulated standard; or b) two years after the IASB publishes the final version of a mandatory rate regulated standard.

PRINCIPLES OF CONSOLIDATION

These unaudited condensed interim Consolidated Financial Statements of AltaGas include the accounts of the Corporation, its subsidiaries, variable interest entities ("VIEs") for which the Corporation is the primary beneficiary, and its interest in various partnerships and joint ventures where AltaGas has an undivided interest in the assets and liabilities. Investments in unconsolidated companies that AltaGas has significant influence, but not control, over are accounted for using the equity method.

All intercompany balances and transactions are eliminated on consolidation. Where there is a party with a non-controlling interest in a subsidiary that AltaGas controls, that non-controlling interest is reflected as “non-controlling interests” in the Consolidated Financial Statements. The non-controlling interests in net income (or loss) of consolidated subsidiaries are shown as an allocation of the consolidated net income and are presented separately in "net income applicable to non-controlling interests".

USE OF ESTIMATES AND MEASUREMENT UNCERTAINTY

The preparation of Consolidated Financial Statements in accordance with U.S. GAAP requires Management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the reported amounts of revenue and expenses during the period. Critical estimates and judgements used in the preparation of these condensed interim Consolidated Financial Statements are described in Note 2 of the Corporation's 2023 annual audited Consolidated Financial Statements. There have been no material changes to AltaGas' critical estimates and judgements during the nine months ended September 30, 2024.

SIGNIFICANT ACCOUNTING POLICIES

These unaudited condensed interim Consolidated Financial Statements have been prepared following the same accounting policies and methods as those used in preparing the Corporation's 2023 annual audited Consolidated Financial Statements.

ADOPTION OF NEW ACCOUNTING STANDARDS

Effective January 1, 2024, AltaGas adopted the following Financial Accounting Standards Board ("FASB") issued Accounting Standards Updates ("ASU"):

- In June 2022, FASB issued ASU No. 2022-03 "Fair Value Measurement (Topic 820): Fair Value Measurement of Equity Securities Subject to Contractual Sale Restrictions". The amendments in this ASU clarify that a contractual restriction on the sale of an equity security is not considered part of the unit of account of the equity security, and therefore, is not considered in measuring fair value. In addition, an entity cannot, as a separate unit of account, recognize a contractual sale restriction. Equity securities subject to contractual sale restrictions also require certain additional disclosures. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements.
- In March 2023, FASB issued ASU No. 2023-01 "Leases (Topic 842): Common Control Arrangements". The relevant amendments in this ASU require entities to amortize leasehold improvements under common control over the economic life of the leasehold improvements as long as the lessee controlled the use of the leased asset. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements.
- In March 2023, FASB issued ASU No. 2023-02 "Investments - Equity Method and Joint Ventures (Topic 323) - Accounting for Investments in Tax Credit Structures Using the Proportional Amortization Method". The amendments in this ASU allow entities the option to elect to account for tax equity investments using the proportional amortization method if certain conditions are met, regardless of the tax credit program from which the income tax credits are received. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements.

FUTURE CHANGES IN ACCOUNTING PRINCIPLES

In October 2023, FASB issued ASU No. 2023-06 "Disclosure Improvements". The amendments in this ASU modify the disclosure or presentation requirements of a variety of topics in the codification as a result of FASB's decision to incorporate disclosures referred to in SEC Release No. 33-10532, which sought to simplify SEC disclosure requirements. The amendments in this ASU allow users to more easily compare entities subject to the SEC's existing disclosures with those entities that were not previously subject to the SEC's requirements. This Update is only effective upon the removal of the related disclosure from SEC regulations with an expiration of June 30, 2027. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements at this time, but may have an impact in future periods as AltaGas is subject to the scope of this ASU.

In November 2023, FASB issued ASU No. 2023-07 "Segment Reporting (Topic 280)". This ASU requires all public entities required to report segment information in accordance with Topic 280 to provide: (1) annual and interim disclosure of significant segment expenses regularly provided to the chief operating decision maker ("CODM"), (2) annual and interim disclosure of other segment items, (3) annual disclosures about reportable segment profit or loss and assets currently required by Topic 280 in interim periods, (4) disclosure of one or more measures of segment profit or loss used by the CODM, provided that at least one of the reported measures includes the segment profit or loss measure that is most consistent with GAAP measurement principles, (5) disclosure of the title and position of the CODM, and (6) a public entity that has a single reportable segment must provide all the disclosures required by this update and all existing segment disclosures in Topic 280. This update is effective for fiscal years beginning after December 31, 2023, and interim periods with fiscal years beginning after December 15, 2024. The adoption of this ASU will have an impact on AltaGas' segment disclosures.

In December 2023, FASB issued ASU No. 2023-09 "Income Taxes (Topic 740): Improvements to Income Tax Disclosures". The amendments in this ASU require that public business entities on an annual basis: (1) disclose additional categories about federal, state, and foreign income taxes in the rate reconciliation table and (2) provide additional information for reconciling items that meet a quantitative threshold. Additionally, entities are required to annually disclose disaggregated income from continuing operations, income tax expense, and income taxes paid (net of refunds received) by certain tax authorities and jurisdictions. This update is effective for annual periods beginning after December 15, 2024. The adoption of this ASU will have an impact on AltaGas' income tax disclosures.

In March 2024, FASB issued ASU No. 2024-01 "Compensation - Stock Compensation (Topic 718)". The amendments in this ASU provide an illustrative example to assist entities that account for profits interest awards as compensation to employees or non-employees to reduce (1) complexity in determining whether a profits interest award is subject to the guidance in Topic 718, and (2) existing diversity in practice. The amendments in this ASU are effective for annual periods beginning after December 15, 2024, and interim periods within those annual periods, and should be applied either (1) retrospectively to all prior periods presented in the financial statements, or (2) prospectively to profits interest and similar awards granted or modified on or after the date at which the entity first applies the amendments. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

3. Pipestone Acquisition

On December 22, 2023, AltaGas closed the previously announced acquisition of natural gas processing and storage infrastructure assets in the Pipestone area of the Alberta Montney (the "Pipestone Acquisition") with Tidewater Midstream and Infrastructure Ltd. ("Tidewater") for consideration upon close of $328 million in cash and approximately 12.5 million AltaGas common shares, inclusive of working capital and other adjustments. The Pipestone Acquisition includes the Pipestone natural gas processing facility Phase I, the Pipestone Phase II expansion project which is being developed, the Dimsdale natural gas storage facility, the Pipestone condensate truck-in/truck-out terminal, and the associated gathering pipeline systems required to operate these assets. Following the completion of key de-risking milestones in December 2023, AltaGas declared a positive final investment decision ("FID") on the Pipestone Phase II expansion project.

AltaGas accounted for the acquisition as a business combination using the acquisition method of accounting whereby the acquired assets and assumed liabilities are recorded at their estimated fair values at the date of acquisition. The excess of purchase price over estimated fair values of assets acquired and liabilities assumed is recognized as goodwill at the acquisition date.

The following table summarizes the preliminary purchase price allocation representing the consideration paid and the estimated fair value of the net assets acquired as at December 22, 2023. The purchase price allocation is preliminary and reflects Management's current best estimate of the fair value of the acquired assets and liabilities based on the analysis of information obtained to date. Management is continuing to obtain specific information to support the valuation of current assets, property, plant and equipment, intangible assets, long term investments and other assets, current liabilities, deferred taxes, and contingencies. As additional information becomes available, the purchase price allocation may differ materially from the preliminary purchase price allocation below. The offset to any adjustments made to the aforementioned financial statement captions during the measurement period are expected to be recorded in goodwill. Any adjustments to the purchase price allocation will be made as soon as practicable but no later than one year from the date of acquisition. No adjustments were made to the purchase price allocation in the first nine months of 2024.

Cash payment	**$**	**328**
Shares issued		**340**
Effective date and other adjustments		**8**
Total purchase consideration	**$**	**676**
Fair value assigned to net assets		
Current assets	**$**	**32**
Property, plant and equipment		**646**
Intangible assets		**30**
Operating right-of-use assets		**3**
Long-term investments and other assets		**5**
Current liabilities		**(52)**
Asset retirement obligations		**(5)**
Deferred income taxes		**(18)**
Operating lease liabilities		**(2)**
Finance lease liabilities		**(96)**
Fair value of net assets acquired	**$**	**543**
Goodwill	**$**	**133**

The preliminary purchase price allocation includes goodwill of approximately $133 million. The goodwill is primarily related to incremental growth opportunities in the Midstream business as a result of the acquisition and greater financial flexibility as a result of increased scale and earnings diversification. The goodwill recognized as part of this transaction is not deductible for income tax purposes, and as such, no deferred taxes have been recorded related to this goodwill.

4. Inventory

As at		**September 30, 2024**		December 31, 2023
Renewable energy credits and emission compliance instruments	**$**	**218**	$	202
Natural gas held in storage [(a)]		**216**		282
Natural gas liquids		**167**		156
Materials and supplies		**66**		66
Crude oil and condensate		**47**		132
Processed finished products		**6**		9
	$	**720**	$	847

(a) As at September 30, 2024, $190 million of the natural gas held in storage was held by rate-regulated utilities (December 31, 2023 - $247 million).

5. Goodwill

As at	September 30, 2024	December 31, 2023
Balance, beginning of period	**$ 5,270**	$ 5,250
Business acquisition *(note 3)*	**—**	133
Foreign exchange translation	**97**	(113)
Balance, end of period	**$ 5,367**	$ 5,270

6. Long-Term Investments and Other Assets

As at	September 30, 2024	December 31, 2023
Deferred lease receivable	**$ 16**	$ 15
Debt issuance costs associated with credit facilities	**5**	4
Refundable deposits	**9**	10
Prepayment on long-term service agreements	**61**	84
Deferred information technology costs	**34**	37
Cash calls from joint venture partners	**16**	19
Contract asset *(net of credit losses of $1 million) (notes 12 and 13)*	**2**	36
Rabbi trust *(notes 18 and 20)*	**4**	6
Capitalized contract costs	**4**	4
Financial transmission rights	**25**	26
Blend-and-extend contract [(a)]	**31**	—
Other	**33**	30
	$ 240	$ 271

(a) Comprised of a long term asset which was previously classified as a contract asset related to a blend-and-extend contract at the Gordondale facility. Due to the change in operatorship of the facility in the third quarter of 2024, the contract is no longer in scope of ASC 606 and is now assessed under ASC 842. The asset will continue to be drawn down into revenue over the remaining term of the contract.

7. Variable Interest Entities

Consolidated VIEs

AltaGas consolidates a VIE where the Corporation is deemed the primary beneficiary. The primary beneficiary of a VIE has the power to direct the activities of the entity that most significantly impact its economic performance such as being the provider of construction, operating, and marketing services to the entity. In addition, the primary beneficiary of a VIE also has the obligation to absorb losses of the entity or the right to receive benefits that could potentially be significant to the VIE. AltaGas determined that it is the primary beneficiary of the following VIEs:

Ridley Island LPG Export Limited Partnership

On May 5, 2017, AltaGas LPG Limited Partnership ("AltaGas LPG"), a wholly-owned subsidiary of AltaGas, and Vopak Development Canada Inc. ("Vopak"), a wholly-owned subsidiary of Koninklijke Vopak N.V. ("Royal Vopak"), a public company incorporated under the laws of the Netherlands, formed the Ridley Island LPG Export Limited Partnership ("RILE LP") to develop, own, and operate the Ridley Island Propane Export Terminal ("RIPET"). AltaGas' subsidiaries hold a 70 percent interest while Vopak holds a 30 percent interest in RILE LP. The construction cost of RIPET was funded by AltaGas LPG and Vopak in proportion to their respective interests in RILE LP. As part of the arrangements, AltaGas entered into a long-term agreement for the capacity of RIPET with RILE LP, and AltaGas and certain of its subsidiaries provide operating services to RILE LP.

AltaGas has determined that RILE LP is a VIE in which it holds variable interests and is the primary beneficiary. In the determination that AltaGas is the primary beneficiary of the VIE, AltaGas noted that it has the power to direct the activities that most significantly impact the VIE's economic performance through the operating and marketing services provided to RILE LP. In addition, AltaGas has the obligation to absorb the losses and the right to receive the benefits that could potentially be significant to RILE LP through the long-term agreement for the capacity of RIPET. As such, AltaGas has consolidated RILE LP.

The assets of RILE LP are the property of RILE LP and are not available to AltaGas for any other purpose. RILE LP's asset balances can only be used to settle its own obligations. The liabilities of RILE LP do not represent additional claims against AltaGas' general assets. AltaGas' exposure to loss as a result of its interest as a limited partner is its net investment. The terms of the long-term capacity agreement between AltaGas LPG and RILE LP provide for a return on and of capital and reimbursement of RIPET's operating costs by AltaGas LPG in accordance with the terms set out in the agreement.

The following table represents amounts included in the Consolidated Balance Sheets attributable to RILE LP:

As at	**September 30, 2024**	December 31, 2023
Current assets	**$ 11**	$ 8
Property, plant and equipment	**345**	349
Long-term investments and other assets	**40**	42
Current liabilities	**(21)**	(15)
Asset retirement obligations	**(5)**	(5)
Net assets	**$ 370**	$ 379

Ridley Island Energy Export Facility Limited Partnership

On April 4, 2023, AltaGas LPG and Vopak formed the Ridley Island Energy Export Facility Limited Partnership ("REEF LP") to develop, own, and operate the Ridley Island Energy Export Facility ("REEF"). AltaGas' subsidiaries and Vopak each hold a 50 percent interest in REEF LP. The construction cost of REEF is being funded by AltaGas LPG and Vopak in proportion to their respective interests in REEF LP. As part of the project definitive agreements, AltaGas entered into a long-term agreement for 100 percent of the capacity of REEF with REEF LP. Additionally, AltaGas and certain of its subsidiaries have been contracted to provide operating and project development services to REEF LP.

AltaGas has determined that REEF LP is a VIE in which it holds variable interests and is the primary beneficiary. In the determination that AltaGas is the primary beneficiary of the VIE, AltaGas noted that it has the power to direct the activities that most significantly impact the VIE's economic performance through its control of all operational and commercial aspects of the project. In addition, AltaGas has the obligation to absorb the losses and the right to receive the benefits that could potentially be significant to REEF LP through the long-term agreement for the capacity of REEF. As such, AltaGas has consolidated REEF LP.

The assets of REEF LP are the property of REEF LP and are not available to AltaGas for any purpose other than as described in the long-term capacity agreement. REEF LP's asset balances can only be used to settle its own obligations and the liabilities of REEF LP do not represent additional claims against AltaGas' general assets. AltaGas' exposure to loss as a result of its interest as a limited partner is its net investment. AltaGas and Royal Vopak have provided limited guarantees for the obligations of their respective subsidiaries for the construction cost of REEF. With the commencement of commercial operations at REEF, the terms of the long-term capacity agreement between AltaGas LPG and REEF LP provide for a return on and of capital and reimbursement of REEF's operating costs by AltaGas LPG in accordance with the terms set out in the agreement.

The following table represents amounts included in the Consolidated Balance Sheets attributable to REEF LP:

As at	**September 30, 2024**	December 31, 2023
Current assets	**$ 42**	$ 7
Property, plant and equipment	**212**	65
Net assets	**$ 254**	$ 72

AltaGas Hybrid Trust

On January 11, 2022, AltaGas closed its offering of $300 million of 5.25 percent Fixed-to-Fixed Rate Subordinated Notes, Series 1 (Note 10). In conjunction with the debt offering, AltaGas issued $300 million in Preferred Shares, Series 2022-A, to be held in the AltaGas Hybrid Trust with Computershare Trust Company of Canada acting as trustee. The Preferred Shares were issued to satisfy the obligations under the indenture governing the associated Series 1 Subordinated Notes. Following the occurrence of certain bankruptcy or insolvency events in respect of AltaGas, subject to certain exceptions, the Series 2022-A Preferred Shares would be delivered to the holders of the Series 1 Subordinated Notes. Upon delivery of the Series 2022-A Preferred Shares, the Series 1 Subordinated Notes would be immediately and automatically surrendered and cancelled and all rights of any Series 1 Subordinated Notes will automatically cease.

On August 17, 2022, AltaGas closed its offering of $250 million of 7.35 percent Fixed-to-Fixed Subordinated Notes, Series 2 (Note 10). In conjunction with the debt offering, AltaGas issued $250 million in Preferred Shares, Series 2022-B, to be held in the AltaGas Hybrid Trust with Computershare Trust Company of Canada acting as trustee. The Preferred Shares were issued to satisfy the obligations under the indenture governing the associated Series 2 Subordinated Notes. Following the occurrence of certain bankruptcy or insolvency events in respect of AltaGas, subject to certain exceptions, the Series 2022-B Preferred Shares would be delivered to the holders of the Series 2

Subordinated Notes. Upon delivery of the Series 2022-B Preferred Shares, the Series 2 Subordinated Notes would be immediately and automatically surrendered and cancelled and all rights of any Series 2 Subordinated Notes will automatically cease.

On November 10, 2023, AltaGas closed its offering of $200 million of 8.90 percent Fixed-to-Fixed Subordinated Notes, Series 3 (Note 10). In conjunction with the debt offering, AltaGas issued $200 million in Preferred Shares, Series 2023-A, to be held in the AltaGas Hybrid Trust with Computershare Trust Company of Canada acting as trustee. The Preferred Shares were issued to satisfy the obligations under the indenture governing the associated Series 3 Subordinated Notes. Following the occurrence of certain bankruptcy or insolvency events in respect of AltaGas, subject to certain exceptions, the Series 2023-A Preferred Shares would be delivered to the holders of the Series 3 Subordinated Notes. Upon delivery of the Series 2023-A Preferred Shares, the Series 3 Subordinated Notes would be immediately and automatically surrendered and cancelled and all rights of any Series 3 Subordinated Notes will automatically cease.

The only assets held by the AltaGas Hybrid Trust are the Series 2022-A, Series 2022-B, and Series 2023-A Preferred Shares.

AltaGas has determined that AltaGas Hybrid Trust is a VIE in which it holds variable interests and is the primary beneficiary. In the determination that AltaGas is the primary beneficiary of the VIE, AltaGas noted that it has the power to direct the activities that most significantly impact the VIE’s economic performance through its role as the sole administrative agent. In addition, AltaGas has the obligation to absorb the administrative expenses that are significant to the trust through the associated administrative agreement. As such, AltaGas has consolidated the AltaGas Hybrid Trust.

Unconsolidated VIE

Strathcona Storage Limited Partnership ("SSLP")

AltaGas owns an interest in SSLP, a partnership formed with ATCO Energy Solutions Ltd. to construct, operate, and maintain underground NGL storage caverns at Fort Saskatchewan, Alberta. The facility currently has five underground NGL storage salt caverns.

As at September 30, 2024, AltaGas' held a 40 percent equity investment in SSLP with a carrying value of $128 million (December 31, 2023 - $130 million). SSLP is not consolidated by AltaGas and instead is accounted for by the equity method of accounting. AltaGas is not the primary beneficiary of SSLP and it does not have the power to direct the activities most significant to the economic performance of SSLP. The maximum financial exposure to loss as a result of the involvement with this VIE is equal to AltaGas' net investment in SSLP.

8. Investments Accounted for by the Equity Method

			Carrying value as at	
	Location	Ownership Percentage	**September 30, 2024**	December 31, 2023
Eaton Rapids Gas Storage System	United States	**50**	**$ 28**	$ 28
Mountain Valley Pipeline, LLC ("MVP") [(a)]	United States	**10**	**559**	511
Sarnia Airport Storage Pool LP	Canada	**50**	**16**	16
Petrogas Terminals Penn LLC	United States	**50**	**1**	1
SSLP	Canada	**40**	**128**	130
			$ 732	$ 686

(a) The equity method is considered appropriate because MVP is an LLC with specific ownership accounts and ownership between five and fifty percent, resulting in AltaGas exercising a more than minor influence over the investee's operating and financing policies.

			Equity income for the three months ended September 30		Equity income for the nine months ended September 30	
	Location	Ownership Percentage	**2024**	2023	**2024**	2023
Eaton Rapids Gas Storage System	United States	**50**	**$ —**	$ 1	**$ 2**	$ 2
MVP [(a)]	United States	**10**	**14**	19	**37**	25
Sarnia Airport Storage Pool LP	Canada	**50**	**—**	—	**1**	1
SSLP	Canada	**40**	**2**	1	**5**	4
			$ 16	$ 21	**$ 45**	$ 32

(a) Relates to allowance for funds used during construction ("AFUDC") prior to June 2024 and equity earnings from income generated by MVP subsequent to being placed in-service on June 14, 2024. Earnings after June 14, 2024 also include the amortization of certain basis differences.

The carrying amount of certain equity investments differs from the amount of the underlying equity in net assets. These basis differences include amounts related to purchase accounting adjustments, capitalized interest, provisions on assets, and a contractual cap on contributions to MVP.

Meade Escrow Proceeds

In 2019, AltaGas completed the disposition of its investment in Meade Pipeline Co. LLC ("Meade"), which held WGL Midstream's indirect, non-operating interest in the Central Penn pipeline ("Central Penn"). Upon close of the sale, various escrow accounts were established to provide the purchaser a form of recourse for the settlement of indemnification and tax obligations. In the third quarter of 2024, AltaGas received approximately $14 million (US$10 million) of cash proceeds from the transfer tax escrow account. As a result, AltaGas recognized a pre-tax gain on disposition of approximately $14 million in the Consolidated Statements of Income (Loss) under the line item "other income" for the three and nine months ended September 30, 2024.

9. Long-Term Debt

As at	Maturity date	September 30, 2024	December 31, 2023
Credit facilities			
$2.3 billion unsecured extendible revolving facility [a]	2-May-2028	**$ —**	$ 484
US$150 million unsecured extendible revolving facility	20-Dec-2026	**40**	86
Commercial paper [b]	Various	**243**	332
$450 million term loan [c]	n/a	**—**	449
AltaGas Ltd. medium-term notes ("MTNs")			
$200 million Senior unsecured - 4.40 percent	15-Mar-2024	**—**	200
$350 million Senior unsecured - 1.23 percent	18-Mar-2024	**—**	350
$300 million Senior unsecured - 3.84 percent	15-Jan-2025	**300**	300
$500 million Senior unsecured - 2.16 percent	10-Jun-2025	**500**	500
$350 million Senior unsecured - 4.12 percent	7-Apr-2026	**350**	350
$400 million Senior unsecured - 4.64 percent	15-May-2026	**400**	400
$200 million Senior unsecured - 2.17 percent	16-Mar-2027	**200**	200
$200 million Senior unsecured - 3.98 percent	4-Oct-2027	**200**	200
$500 million Senior unsecured - 2.08 percent	30-May-2028	**500**	500
$400 million Senior unsecured - 4.67 percent	8-Jan-2029	**400**	—
$200 million Senior unsecured - 2.48 percent	30-Nov-2030	**200**	200
$350 million Senior unsecured - 5.14 percent	14-Mar-2034	**350**	—
$100 million Senior unsecured - 5.16 percent	13-Jan-2044	**100**	100
$300 million Senior unsecured - 4.50 percent	15-Aug-2044	**300**	300
$250 million Senior unsecured - 4.99 percent	4-Oct-2047	**250**	250
$500 million Senior unsecured - 5.60 percent	14-Mar-2054	**500**	—
WGL and Washington Gas MTNs and private placement notes			
US$41 million Senior unsecured - 5.44 percent	11-Aug-2025	**55**	54
US$53 million Senior unsecured - 6.62 to 6.82 percent	Oct 2026	**72**	70
US$72 million Senior unsecured - 6.40 to 6.57 percent	Feb - Sep 2027	**98**	95
US$52 million Senior unsecured - 6.57 to 6.85 percent	Jan - Mar 2028	**71**	69
US$9 million Senior unsecured - 7.50 percent	1-Apr-2030	**11**	11
US$150 million Senior unsecured - 6.06 percent	14-Oct-2033	**202**	199
US$50 million Senior unsecured - 5.70 to 5.78 percent	Jan - Mar 2036	**67**	66
US$75 million Senior unsecured - 5.21 percent	3-Dec-2040	**101**	99
US$75 million Senior unsecured - 5.00 percent	15-Dec-2043	**101**	99
US$300 million Senior unsecured - 4.22 to 4.60 percent	Sep - Nov 2044	**405**	397
US$450 million Senior unsecured - 3.80 percent	15-Sep-2046	**607**	595
US$400 million Senior unsecured - 3.65 percent	15-Sep-2049	**540**	529
US$200 million Senior unsecured - 2.98 percent	15-Dec-2051	**270**	265
US$25 million Senior unsecured - 5.25 percent	29-Dec-2042	**34**	33
US$175 million Senior unsecured - 5.33 percent	29-Dec-2052	**236**	231
US$50 million Senior unsecured - 6.43 percent	15-Oct-2053	**67**	66
SEMCO long-term debt			
US$225 million First Mortgage Bonds - 2.45 percent	21-Apr-2030	**97**	95
US$225 million First Mortgage Bonds - 3.15 percent	21-Apr-2050	**304**	298
Fair value adjustment on WGL Acquisition		**73**	74
		$ 8,244	$ 8,546
Less: unamortized premiums, discounts, and debt issuance costs		**(32)**	(19)
		$ 8,212	$ 8,527
Less: current portion		**(854)**	(999)
		$ 7,358	$ 7,528

(a) Borrowings on the facility can be by way of prime loans, U.S. base-rate loans, SOFR loans, term CORRA loans, or letters of credit. Borrowings on the facility have fees and interest at rates relevant to the nature of the draw made. This facility has a $1.7 billion four-year extendable committed revolving tranche and a $600 million three-year extendable side car revolving tranche which matures in May 2027.

(b) Commercial paper is supported by the availability of long-term committed credit facilities maturing in 2026. Commercial paper intended to be repaid within the next year is recorded as short-term debt.

(c) The term loan was cancelled and repaid in full on June 28, 2024.

10. Subordinated Hybrid Notes

As at	Maturity date		September 30, 2024		December 31, 2023
$300 million Subordinated Notes, Series 1 - 5.25 percent [a]	11-Jan-2082	**$**	**300**	$	300
$250 million Subordinated Notes, Series 2 - 7.35 percent [b]	17-Aug-2082		**250**		250
$200 million Subordinated Notes, Series 3 - 8.90 percent [c]	10-Nov-2083		**200**		200
US$900 million Subordinated Notes - 7.20 percent [d] [e]	15-Oct-2054		**1,215**		—
		$	**1,965**	$	750
Less: debt issuance costs			**(20)**		(8)
		$	**1,945**	$	742

(a) For the initial 10 years, the Notes carry a fixed interest rate. From January 11, 2032, and on every fifth anniversary of such date thereafter, the interest rate will reset for the subsequent fixed rate period at a rate per annum equal to the five year Government of Canada yield plus for the period from January 11, 2032 to, but excluding, January 11, 2052, 3.82 percent and for the period from January 11, 2052 to, but excluding, the maturity date, 4.57 percent.

(b) For the initial 5 years, the Notes carry a fixed interest rate. From August 17, 2027, and on every fifth anniversary of such date thereafter, the interest rate will reset for the subsequent fixed rate period at a rate per annum equal to the five year Government of Canada yield plus for the period from August 17, 2027 to, but excluding, August 17, 2032, 4.54 percent, for the period from August 17, 2032, to, but excluding, August 17, 2047, 4.79 percent, and for the period from August 17, 2047, to, but excluding, the maturity date, 5.54 percent.

(c) For the initial 5 years, the Notes carry a fixed interest rate. From November 10, 2028, and on every fifth anniversary of such date thereafter, the interest rate will reset for the subsequent fixed rate period at a rate per annum equal to the five year Government of Canada yield plus for the period from November 10, 2028 to, but excluding, November 10, 2033, 5.09 percent, for the period from November 10, 2033 to, but excluding, November 10, 2048, 5.34 percent, and for the period from November 10, 2048, to, but excluding, the Maturity date, 6.09 percent.

(d) For the initial 10 years, the Notes carry a fixed interest rate. From October 15, 2034, the interest rate will reset for the subsequent fixed rate period at a rate per annum equal to the five year treasury rate plus 3.57 percent.

(e) AltaGas concurrently executed cross-currency swaps totaling US$900 million, which will convert the U.S. dollar principal and interest payments of these Notes into Canadian dollars and apply an effective annual interest rate of 6.90 percent on the converted Canadian principal amount of approximately $1.2 billion. Refer to Note 13 for more details.

For the three and nine months ended September 30, 2024, AltaGas recorded interest expense of $15 million and $41 million, respectively, on the subordinated hybrid notes (three and nine months ended September 30, 2023 - $9 million and $26 million, respectively).

11. Accumulated Other Comprehensive Income (Loss)

		Cash Flow Hedges	DB pension and PRB plans	Hedge net investments	Translation foreign operations	Total
Opening balance, January 1, 2024	**$**	**(9) $**	**(2) $**	**(148) $**	**554 $**	**395**
OCI before reclassification		**(65)**	**1**	**(19)**	**210**	**127**
Amounts reclassified from OCI		**18**	**(2)**	**—**	**—**	**16**
Current period OCI (pre-tax)	**$**	**(47) $**	**(1) $**	**(19) $**	**210 $**	**143**
Income tax on amounts retained in AOCI		**4**	**—**	**2**	**—**	**6**
Net current period OCI	**$**	**(43) $**	**(1) $**	**(17) $**	**210 $**	**149**
Ending balance, September 30, 2024	**$**	**(52) $**	**(3) $**	**(165) $**	**764 $**	**544**
Opening balance, January 1, 2023	$	— $	(5) $	(173) $	804 $	626
OCI before reclassification		—	(1)	7	(21)	(15)
Amounts reclassified from OCI		—	2	—	—	2
Current period OCI (pre-tax)	$	— $	1 $	7 $	(21) $	(13)
Income tax on accounts retained in AOCI		—	—	(1)	—	(1)
Net current period OCI	$	— $	1 $	6 $	(21) $	(14)
Ending balance, September 30, 2023	$	— $	(4) $	(167) $	783 $	612

Reclassification From Accumulated Other Comprehensive Income (Loss)

AOCI components reclassified	Income statement line item		**Three Months Ended September 30, 2024**	Three Months Ended September 30, 2023
			Gain (loss)	Gain (loss)
Cash flow hedges - commodity contracts	Cost of sales	**$**	**(2) $**	—
Cash flow hedges - bond forward contract	Interest expense		**(Less than $1 million)**	—
Cash flow hedges - cross-currency swaps	Foreign exchange gains (losses)		**(9)**	—
DB pension and PRB plans [(a)]	Other income (loss)		**2**	—
		$	**(9) $**	—

(a) Reclassification from AOCI for the three months ended September 30, 2024 relates to the partial settlement of WGL's post-retirement benefit plan. Refer to Note 18 for more details.

AOCI components reclassified	Income statement line item		**Nine Months Ended September 30, 2024**	Nine Months Ended September 30, 2023
			Gain (loss)	Gain (loss)
Cash flow hedges - commodity contracts	Cost of sales	**$**	**(9) $**	—
Cash flow hedges - bond forward contract	Interest expense		**(Less than $1 million)**	—
Cash flow hedges - cross-currency swaps	Foreign exchange gains (losses)		**(9)**	—
DB pension and PRB plans [(a)]	Other income (loss)		**2**	(2)
		$	**(16) $**	(2)

(a) Reclassification from AOCI for the nine months ended September 30, 2024 relates to the partial settlement of WGL's post-retirement benefit plan. Refer to Note 18 for more details. Reclassification from AOCI for the nine months ended September 30, 2023 relates to the loss on the wind-up of the Canadian defined benefit pension plan.

12. Revenue

The following tables disaggregate revenue by major sources for the period:

	Three Months Ended September 30, 2024			
	Utilities	Midstream	Corporate/ Other	Total
Revenue from contracts with customers				
Commodity sales contracts	$ 543	$ 1,534	$ 21	$ 2,098
Midstream service contracts	—	393	—	393
Gas sales and transportation services	266	—	—	266
Storage services	—	7	—	7
Other [a]	2	—	12	14
Total revenue from contracts with customers	$ 811	$ 1,934	$ 33	$ 2,778
Other sources of revenue				
Revenue from alternative revenue programs [b]	$ 21	$ —	$ —	$ 21
Leasing revenue [c]	—	61	—	61
Risk management and trading activities [d]	9	(109)	—	(100)
Other	(2)	1	—	(1)
Total revenue from other sources	$ 28	$ (47)	$ —	$ (19)
Total revenue	$ 839	$ 1,887	$ 33	$ 2,759

(a) The Corporate/Other segment includes revenue earned from a resource adequacy agreement at Blythe that came into effect January 1, 2024. Prior to that, Blythe was contracted under a power purchase agreement until December 31, 2023.

(b) A large portion of revenue generated from the Utilities segment is subject to rate regulation and accordingly there are circumstances where the revenue recognized is mandated by the applicable regulators in accordance with ASC 980.

(c) Revenue generated from certain of AltaGas' Midstream facilities is accounted for as operating leases.

(d) Risk management activities involve the use of derivative instruments such as physical and financial swaps, and commodity and foreign exchange forward contracts. These derivatives are accounted for under ASC 815 and ASC 825. A portion of revenue generated by the Utilities segment is from the physical sale and delivery of natural gas and power to end users.

	Three Months Ended September 30, 2023			
	Utilities	Midstream	Corporate/ Other	Total
Revenue from contracts with customers				
Commodity sales contracts	$ 501	$ 1,872	$ —	$ 2,373
Midstream service contracts	—	356	—	356
Gas sales and transportation services	265	2	—	267
Other	3	—	—	3
Total revenue from contracts with customers	$ 769	$ 2,230	$ —	$ 2,999
Other sources of revenue				
Revenue from alternative revenue programs [a]	$ 20	$ —	$ —	$ 20
Leasing revenue [b]	—	62	26	88
Risk management and trading activities [c]	(24)	(68)	—	(92)
Other	2	13	—	15
Total revenue from other sources	$ (2)	$ 7	$ 26	$ 31
Total revenue	$ 767	$ 2,237	$ 26	$ 3,030

(a) A large portion of revenue generated from the Utilities segment is subject to rate regulation and accordingly there are circumstances where the revenue recognized is mandated by the applicable regulators in accordance with ASC 980.

(b) Revenue generated from certain of AltaGas' Midstream facilities is accounted for as operating leases. For the Corporate/Other segment, a significant amount of revenue earned was through power purchase agreements which were accounted for as operating leases.

(c) Risk management activities involve the use of derivative instruments such as physical and financial swaps, and commodity and foreign exchange forward contracts. These derivatives are accounted for under ASC 815 and ASC 825. A portion of revenue generated by the Utilities segment is from the physical sale and delivery of natural gas and power to end users.

	Nine Months Ended September 30, 2024			
	Utilities	**Midstream**	**Corporate / Other**	**Total**
Revenue from contracts with customers				
Commodity sales contracts	**$ 1,580**	**$ 4,655**	**$ 38**	**$ 6,273**
Midstream service contracts	**—**	**1,036**	**—**	**1,036**
Gas sales and transportation services	**1,557**	**—**	**—**	**1,557**
Storage services	**—**	**26**	**—**	**26**
Other [(a)]	**7**	**—**	**29**	**36**
Total revenue from contracts with customers	**$ 3,144**	**$ 5,717**	**$ 67**	**$ 8,928**
Other sources of revenue				
Revenue from alternative revenue programs [(b)]	**$ 122**	**$ —**	**$ —**	**$ 122**
Leasing revenue [(c)]	**—**	**170**	**—**	**170**
Risk management and trading activities [(d)]	**(20)**	**(13)**	**—**	**(33)**
Other	**(5)**	**7**	**—**	**2**
Total revenue from other sources	**$ 97**	**$ 164**	**$ —**	**$ 261**
Total revenue	**$ 3,241**	**$ 5,881**	**$ 67**	**$ 9,189**

(a) The Corporate/Other segment includes revenue earned from a resource adequacy agreement at Blythe that came into effect January 1, 2024. Prior to that, Blythe was contracted under a power purchase agreement until December 31, 2023.
(b) A large portion of revenue generated from the Utilities segment is subject to rate regulation and accordingly there are circumstances where the revenue recognized is mandated by the applicable regulators in accordance with ASC 980.
(c) Revenue generated from certain of AltaGas' gas facilities is accounted for as operating leases.
(d) Risk management activities involve the use of derivative instruments such as physical and financial swaps, and commodity and foreign exchange forward contracts. These derivatives are accounted for under ASC 815 and ASC 825. A portion of revenue generated by the Utilities segment is from the physical sale and delivery of natural gas and power to end users.

	Nine Months Ended September 30, 2023			
	Utilities	Midstream	Corporate/ Other	Total
Revenue from contracts with customers				
Commodity sales contracts	$ 1,469	$ 4,627	$ —	$ 6,096
Midstream service contracts	—	1,292	—	1,292
Gas sales and transportation services	1,813	6	—	1,819
Storage services [(a)]	4	—	—	4
Other	9	5	—	14
Total revenue from contracts with customers	$ 3,295	$ 5,930	$ —	$ 9,225
Other sources of revenue				
Revenue from alternative revenue programs [(b)]	$ 120	$ —	$ —	$ 120
Leasing revenue [(c)]	—	170	70	240
Risk management and trading activities [(d)]	126	(36)	2	92
Other	(2)	34	—	32
Total revenue from other sources	$ 244	$ 168	$ 72	$ 484
Total revenue	$ 3,539	$ 6,098	$ 72	$ 9,709

(a) Relates to revenue earned for the period prior to the close of AltaGas' sale of its 100 percent interest in ENSTAR Natural Gas Company ("ENSTAR") and 65 percent indirect interest in Cook Inlet Natural Gas Storage Alaska ("CINGSA") and other ancillary operations in Alaska, which were divested to TriSummit Utilities Inc. on March 1, 2023 (the "Alaska Utilities Disposition").
(b) A large portion of revenue generated from the Utilities segment is subject to rate regulation and accordingly there are circumstances where the revenue recognized is mandated by the applicable regulators in accordance with ASC 980.
(c) Revenue generated from certain of AltaGas' gas facilities is accounted for as operating leases. For the Corporate/Other segment, a significant amount of revenue earned was through power purchase agreements which were accounted for as operating leases.
(d) Risk management activities involve the use of derivative instruments such as physical and financial swaps, and commodity and foreign exchange forward contracts. These derivatives are accounted for under ASC 815 and ASC 825. A portion of revenue generated by the Utilities segment is from the physical sale and delivery of natural gas and power to end users.

Revenue Recognition

The following is a description of the Corporation's revenue recognition policy by segment and by major source of revenue from contracts with customers.

Utilities Segment

Gas Sales and Transportation Services

Customers are billed monthly based on regular meter readings. Customer billings are based on two main components: (i) a fixed service fee and (ii) a variable fee based on usage. Revenue is recognized over time when the gas has been delivered or as the service has been performed. As meter readings are performed on a cycle basis, AltaGas recognizes accrued revenue for any services rendered to its customers but not billed at month-end. The vast majority of these contracts are "at-will" as customers may cancel their service at any time, however, there are certain contracts that have terms of one year or longer. For these long-term contracts, there is generally a contract demand specified in the contract whereby the customer has to pay regardless of whether or not gas has been delivered. These contracts generally do not contain any make up rights and revenue is recognized on a monthly basis as service has been performed.

Commodity Sales

Commodity sales include natural gas and electricity sales to residential, commercial, and industrial customers in certain states where WGL Energy Services is authorized as a competitive service provider. These commodity sales contracts have varying terms that generally range from one to five years. Customers are billed monthly based on the amount of energy delivered to the customer. Revenue is recognized based on the amount the Corporation is entitled to invoice the customer.

Midstream Segment

Commodity Sales

A portion of the NGL production from AltaGas' extraction facilities is subject to frac spread between NGLs extracted and the natural gas purchased to make up the heating value of the NGLs extracted. For commodity sales contracts that do not meet the definition of a derivative or for contracts whereby AltaGas has elected to apply the normal purchase normal sales scope exception, the sales contract is accounted for under ASC 606. These commodity sales contracts have varying terms, but the majority of the contracts have a one-year term which coincides with the NGL year. AltaGas recognizes revenue for commodity sales contracts at a point in time based on the actual volumes of the commodity sold at the delivery point, which corresponds to the customer's monthly invoice amount.

Commodity sales contracts at RIPET and Ferndale generate revenue from the sale and delivery of LPGs to customers in Asia shipped from offshore export terminals. Revenue is recognized when LPGs are loaded onto transport vessels, which is the delivery point. AltaGas has the right to consideration in an amount that directly corresponds to the volumes of LPGs loaded on a vessel. AltaGas' commodity sales also include the sale of upgraded crude oil, processed finished products, and various fuels. Delivery takes place when there is a sales contract in place, specifying delivery volumes and sales prices. The consideration received under these contracts is variable based on commodity prices.

Effective July 1, 2024, WGL entered into an agreement for the sale of natural gas related to the in-service of MVP. These gas sales are accounted for under ASC 606.

Midstream Service Contracts

AltaGas earns revenue from its field gathering and processing facilities, extraction facilities, storage facilities, truck hauling services, rail and truck loading and unloading terminalling, and transmission systems through a variety of contractual arrangements. For arrangements that do not contain a lease, the revenue is accounted for under ASC 606 as follows:

Fee-for-service – The customer is charged a fee for the service provided on a per unit volume basis. Contract terms generally range from one month to up to the life of the reserves. Revenue under this type of arrangement is recognized over time as the service is provided, which corresponds to the customer's monthly invoice amount.

Take-or-pay – The customer has agreed to a minimum volume commitment whereby the customer must have AltaGas process or deliver a specified volume at a rate per unit that is specified in the contract. Quantities that the customer is unable to deliver are considered deficiency quantities. Certain of AltaGas' take-or-pay contracts contain provisions whereby the customer can make up deficiency quantities in subsequent periods. Under this type of arrangement, any consideration received relating to the deficiency quantities that will be made up in a future period will be deferred until either: (i) the customer makes up the volumes or (ii) the likelihood that the customer will make up the volumes before the make up period expires becomes remote. If AltaGas does not expect the customer to make up the deficiency quantities (also referred to as breakage amount), AltaGas may recognize the expected breakage amount as revenue before the make up period expires. Significant judgment is required in estimating the breakage amount. For contracts where the customer has no make up rights, revenue is recognized on a monthly basis based on the higher of (i) the actual quantity delivered times the per unit rate or (ii) the contracted minimum amount.

Storage fees are typically recognized in revenue ratably over the term of the contract and rail and truck loading and unloading fees are recognized when the volumes are delivered or received.

Corporate/Other Segment

For the Corporate/Other segment, the majority of revenue relates to remaining power assets, from which revenue is primarily earned through a resource adequacy agreement as well as commodity sales via a merchant market, or via commodity sales agreements which are accounted for as financial instruments. For commodity sales contracts that do not meet the definition of a derivative or whereby AltaGas has elected to apply the normal purchase normal sales scope exception, revenue recognized is accounted for under ASC 606.

Contract Balances

As at September 30, 2024, a contract asset balance of $2 million (December 31, 2023 - $40 million) has been recorded on the Consolidated Balance Sheets, of which $3 million ($2 million net of credit losses) is included within long-term investments and other assets (December 31, 2023 - $36 million net of credit losses) and $nil within prepaid expenses and other current assets (December 31, 2023 - $4 million). This contract asset represents the difference in revenue recognized under new rates in a blend-and-extend contract modification with a customer. Revenue from this contract modification was recognized at the pre-modification rate until the effective date of the contract modification on the original contract, with the excess revenue recorded as a contract asset. The contract asset is now being drawn down over the remaining term of the modified contract.

Contract Assets

As at	September 30, 2024	December 31, 2023
Balance, beginning of period	**$ 40**	$ 41
Additions	**—**	3
Amortization [(a)]	**(2)**	(4)
Transfers to other assets [(b)] *(note 6)*	**(36)**	—
Balance, end of period	**$ 2**	$ 40

(a) Represents the drawdown of contract assets under blend-and-extend contract modifications.

(b) Relates to a blend-and-extend contract at the Gordondale facility which was previously classified as a contract asset. Due to the change in operatorship of the facility in the third quarter of 2024, the contract is no longer in scope of ASC 606 and is now assessed under ASC 842. The balance has subsequently been transferred to "prepaid expenses and other current assets" and "long-term investments and other assets" for its current and long-term portions, respectively. The asset will continue to be drawn down into revenue over the remaining term of the contract.

Transaction Price Allocated to the Remaining Obligations

The following table includes estimated revenue expected to be recognized in the future related to performance obligations that are unsatisfied as of September 30, 2024:

	Remainder of 2024	2025	2026	2027	2028	> 2028	Total
Midstream service contracts	$ —	$ 11	$ 15	$ 15	$ 15	$ 48	**$ 104**
Other revenue from contracts with customers	13	50	50	50	—	4	**167**
	$ 13	$ 61	$ 65	$ 65	$ 15	$ 52	**$ 271**

AltaGas applies the practical expedient available under ASC 606 and does not disclose information about the remaining performance obligations for (i) contracts with an original expected length of one year or less, (ii) contracts for which revenue is recognized at the amount to which AltaGas has the right to invoice for performance completed, and (iii) contracts with variable consideration that is allocated entirely to a wholly unsatisfied performance obligation or to a wholly unsatisfied promise to transfer a distinct good or service that forms part of a single performance obligation. In addition, the table above does not include any estimated amounts of variable consideration that are constrained. The majority of midstream service contracts, gas sales and transportation service contracts, and storage service contracts contain variable consideration whereby uncertainty related to the associated variable consideration will be resolved (usually on a daily basis) as volumes are processed, gas is delivered or as service is provided.

13. Financial Instruments and Financial Risk Management

The Corporation's financial instruments consist of cash and cash equivalents, accounts receivable, risk management contracts, certain long-term investments and other assets, accounts payable and accrued liabilities, dividends payable, short-term and long-term debt, and certain other current and long-term liabilities.

Fair Value Hierarchy

AltaGas categorizes its financial assets and financial liabilities into one of three levels based on fair value measurements and inputs used to determine the fair value.

Level 1 - fair values are based on unadjusted quoted prices in active markets for identical assets or liabilities. Fair values are based on direct observations of transactions involving the same assets or liabilities and no assumptions are used. Included in this category are publicly traded shares valued at the closing price as at the balance sheet date.

Level 2 - fair values are determined based on valuation models and techniques where inputs other than quoted prices included within Level 1 are observable for the asset or liability either directly or indirectly. AltaGas enters into derivative instruments in the futures, over-the-counter, and retail markets to manage fluctuations in commodity prices and foreign exchange rates. The fair values of power, natural gas, NGL, LPG, ocean freight, and crude oil derivative contracts were calculated using forward prices based on published sources for the relevant period, adjusted for factors specific to the asset or liability, including basis and location differentials, discount rates, and currency exchange. The fair value of foreign exchange derivative contracts and cross-currency swaps were calculated using indicative broker quotes based on observable market data.

Level 3 - fair values are based on inputs for the asset or liability that are not based on observable market data. AltaGas uses valuation techniques when observable market data is not available. Level 3 derivatives include physical contracts at illiquid market locations with no observable market data, long-dated positions where observable pricing is not available over the life of the contract, contracts valued using historical spot price volatility assumptions, and valuations using indicative broker quotes for inactive market locations. A significant change to any one of these inputs in isolation could result in a significant upward or downward fluctuation in the fair value measurement.

The following methods and assumptions were used to estimate the fair value of each significant class of financial instruments:

Other current liabilities - the carrying amounts approximate fair value because of the short maturity of these instruments.

Current portion of long-term debt, long-term debt, current portion of finance lease liabilities, finance lease liabilities, subordinated hybrid notes, and other long-term liabilities - the fair value of these liabilities was estimated based on discounted future interest and principal payments using the current market interest rates of instruments with similar terms.

Risk management assets and liabilities - the fair values of power, natural gas, NGL, and crude oil derivative contracts were calculated using forward prices from published sources for the relevant period. The fair value of foreign exchange derivative contracts was calculated using quoted market rates. The fair value of Level 3 derivative contracts was calculated using internally developed valuation inputs and pricing models.

Loans and receivables - the fair value of these assets was estimated based on discounted future interest and principal payments using the current market interest rates of instruments with similar terms.

As at	September 30, 2024				
	Carrying Amount	Level 1	Level 2	Level 3	Total Fair Value
Financial assets					
Fair value through net income [(a) (b) (c)]					
Risk management assets - current	$ 36	$ —	$ 11	$ 25	$ 36
Risk management assets - non-current	47	—	35	12	47
Fair value through regulatory assets [(a)]					
Risk management assets - current	4	—	—	4	4
Risk management assets - non-current	9	—	—	9	9
	$ 96	$ —	$ 46	$ 50	$ 96
Financial liabilities					
Fair value through net income [(a) (b) (c)]					
Risk management liabilities - current	$ 147	$ —	$ 130	$ 17	$ 147
Risk management liabilities - non-current	134	—	89	45	134
Fair value through regulatory liabilities [(a)]					
Risk management liabilities - current	11	—	—	11	11
Risk management liabilities - non-current	40	—	—	40	40
Amortized cost					
Current portion of long-term debt	854	—	854	—	854
Current portion of finance lease liabilities	22	—	22	—	22
Long-term debt	7,358	—	6,775	—	6,775
Finance lease liabilities	122	—	122	—	122
Subordinated hybrid notes	1,945	—	1,996	—	1,996
Other current liabilities [(d)]	35	—	35	—	35
	$ 10,668	$ —	$ 10,023	$ 113	$ 10,136

(a) To manage price risk associated with acquiring natural gas supply for Maryland, Virginia, and District of Columbia utility customers, Washington Gas, a subsidiary of the Corporation, enters into physical and financial derivative transactions. Any gains and losses associated with these derivatives are recorded as regulatory liabilities or assets, respectively, to reflect the rate treatment for these economic hedging activities. Additionally, as part of its asset optimization program, Washington Gas enters into derivatives with the primary objective of securing operating margins that Washington Gas will ultimately realize. Regulatory sharing mechanisms provide for the annual realized profit from these transactions to be shared between Washington Gas' shareholder and customers; therefore, changes in fair value are recorded through earnings, or as regulatory assets or liabilities to the extent that it is probable that realized gains and losses associated with these derivative transactions will be included in the rates charged to customers when they are realized.

(b) Includes the fair value of designated commodity hedging instruments classified as level 2 totaling $7 million. The change in fair value of these instruments is recorded to AOCI. Refer to the *Cash Flow Hedges* section below for more details.

(c) Includes the fair value of designated cross-currency swap hedging instruments classified as level 2 totaling $47 million. The change in fair value of these instruments is recorded to AOCI. Refer to the *Foreign Exchange Risk* and *Cash Flow Hedges* sections below for more details.

(d) Excludes non-financial liabilities.

As at	December 31, 2023				
	Carrying Amount	Level 1	Level 2	Level 3	Total Fair Value
Financial assets					
Fair value through net income [(a) (b)]					
Risk management assets - current	$ 49	$ —	$ 17	$ 32	$ 49
Risk management assets - non-current	37	—	12	25	37
Fair value through regulatory assets [(a)]					
Risk management assets - current	5	—	—	5	5
Risk management assets - non-current	20	—	—	20	20
	$ 111	$ —	$ 29	$ 82	$ 111
Financial liabilities					
Fair value through net income [(a) (b)]					
Risk management liabilities - current	$ 85	$ —	$ 51	$ 34	$ 85
Risk management liabilities - non-current	70	—	25	45	70
Fair value through regulatory liabilities [(a)]					
Risk management liabilities - current	12	—	1	11	12
Risk management liabilities - non-current	45	—	—	45	45
Amortized cost					
Current portion of long-term debt	999	—	999	—	999
Current portion of finance lease liabilities	11	—	11	—	11
Long-term debt	7,528	—	6,812	—	6,812
Finance lease liabilities	120	—	120	—	120
Subordinated hybrid notes	742	—	700	—	700
Other current liabilities [(c)]	43	—	43	—	43
	$ 9,655	$ —	$ 8,762	$ 135	$ 8,897

(a) To manage price risk associated with acquiring natural gas supply for Maryland, Virginia, and District of Columbia utility customers, Washington Gas, a subsidiary of the Corporation, enters into physical and financial derivative transactions. Any gains and losses associated with these derivatives are recorded as regulatory liabilities or assets, respectively, to reflect the rate treatment for these economic hedging activities. Additionally, as part of its asset optimization program, Washington Gas enters into derivatives with the primary objective of securing operating margins that Washington Gas will ultimately realize. Regulatory sharing mechanisms provide for the annual realized profit from these transactions to be shared between Washington Gas' shareholder and customers; therefore, changes in fair value are recorded through earnings, or as regulatory assets or liabilities to the extent that it is probable that realized gains and losses associated with these derivative transactions will be included in the rates charged to customers when they are realized.

(b) Includes the fair value of designated hedging instruments classified as level 2 totaling $9 million. The change in fair value of these instruments is recorded to AOCI. Refer to the *Cash Flow Hedges* section below for more details.

(c) Excludes non-financial liabilities.

Financial assets and liabilities not included in the fair value hierarchy table include money market funds, and short-term debt. The carrying value of these financial instruments approximate their fair value, which reflects the short-term maturity and/or normal credit terms of these financial instruments.

The following table includes quantitative information about the significant unobservable inputs used in the fair value measurement of Level 3 financial instruments at September 30, 2024:

	Net Fair Value	Valuation Technique	Unobservable Inputs	Range	Weighted Average [(a)]
Natural gas	$ (49)	Discounted Cash Flow	Natural Gas Basis Price (per Dth)	$ (1.97) - $ 8.22	$ (0.22)
Natural gas	$ (1)	Option Model	Natural Gas Basis Price (per Dth)	$ (1.92) - $ 2.75	$ (0.58)
			Annualized Volatility of Spot Market Natural Gas	9 % - 61 %	23 %
Electricity	$ (13)	Discounted Cash Flow	Electricity Congestion Price (per MWh)	$ (30.74) - $ 117.51	$ 26.44

(a) Unobservable inputs were weighted by transaction volume.

The following tables provide a reconciliation of changes in net fair value of derivative assets and liabilities classified as Level 3 in the fair value hierarchy:

Three Months Ended	**September 30, 2024**			September 30, 2023		
	Natural Gas	**Electricity**	**Total**	Natural Gas	Electricity	Total
Balance, beginning of period	**$ (7)**	**$ —**	**$ (7)**	$ (4)	$ (7)	$ (11)
Realized and unrealized losses:						
Recorded in income [(a)]	**(22)**	**(9)**	**(31)**	(6)	(28)	(34)
Recorded in regulatory assets [(b)]	**(23)**	**—**	**(23)**	(9)	—	(9)
Purchases	**—**	**7**	**7**	—	8	8
Settlements	**2**	**(11)**	**(9)**	7	(9)	(2)
Foreign exchange translation	**—**	**—**	**—**	—	(1)	(1)
Balance, end of period	**$ (50)**	**$ (13)**	**$ (63)**	$ (12)	$ (37)	$ (49)

(a) Includes unrealized losses of $36 million and $11 million for the three months ended September 30, 2024 and 2023, respectively.
(b) Includes unrealized losses of $23 million and $9 million for the three months ended September 30, 2024 and 2023, respectively.

Nine Months Ended	**September 30, 2024**			September 30, 2023		
	Natural Gas	**Electricity**	**Total**	Natural Gas	Electricity	Total
Balance, beginning of period	**$ (30)**	**$ (23)**	**$ (53)**	$ (226)	$ (166)	$ (392)
Realized and unrealized gains (losses):						
Recorded in income [(a)]	**(15)**	**54**	**39**	83	154	237
Recorded in regulatory assets [(b)]	**(9)**	**—**	**(9)**	114	—	114
Transfers out of Level 3	**—**	**(1)**	**(1)**	(6)	(6)	(12)
Purchases	**—**	**(13)**	**(13)**	—	(5)	(5)
Settlements	**4**	**(28)**	**(24)**	22	(13)	9
Foreign exchange translation	**—**	**(2)**	**(2)**	1	(1)	—
Balance, end of period	**$ (50)**	**$ (13)**	**$ (63)**	$ (12)	$ (37)	$ (49)

(a) Includes unrealized gains of $17 million and $144 million for the nine months ended September 30, 2024 and 2023, respectively.
(b) Includes unrealized gains of $23 million and $111 million for the nine months ended September 30, 2024 and 2023, respectively.

Transfers between different levels of the fair value hierarchy may occur based on fluctuations in the valuation and on the level of observable inputs used to value the instruments from period to period. Transfers into and out of the different levels of the fair value hierarchy are presented at the fair value as of the beginning of the period. Transfers out of Level 3 during the nine months ended September 30, 2024 were due to an increase in valuations using observable market inputs.

Summary of Unrealized Gains (Losses) on Risk Management Contracts Recognized in Net Income (Loss)

	Three Months Ended September 30		Nine Months Ended September 30	
	2024	2023	**2024**	2023
Natural gas	**$ (32)**	$ (4)	**$ 19**	$ 17
Energy exports	**(33)**	(77)	**(38)**	(28)
Crude oil and NGLs	**(2)**	1	**(3)**	11
NGL frac spread	**10**	(17)	**(3)**	3
Power	**1**	7	**19**	22
Foreign exchange	**19**	(1)	**(4)**	(1)
	$ (37)	$ (91)	**$ (10)**	$ 24

Offsetting of Derivative Assets and Derivative Liabilities

Certain of AltaGas' risk management contracts are subject to master netting arrangements that create a legally enforceable right for a counterparty to offset the related financial assets and financial liabilities. As part of these master netting agreements, cash, letters of credit, and parental guarantees may be required to be posted or obtained from counterparties in order to mitigate credit risk related to both derivative and non-derivative positions. Collateral balances are also offset against the related counterparties' derivative positions to the extent the application would not result in the over-collateralization of those derivative positions on the balance sheet.

As at	September 30, 2024									
	Derivative instruments not designated as hedging instruments				Derivative instruments designated as hedging instruments					
	Gross amounts of recognized assets/liabilities		Gross amounts offset in balance sheet		Gross amounts of recognized assets/liabilities		Netting of collateral		Net amounts presented in balance sheet	
Risk management assets [a]										
Natural gas	$	71	$	(42)	$	1	$	—	$	30
Energy exports		59		(52)		—		14		21
Crude oil and NGLs		1		—		—		4		5
Power		69		(44)		—		—		25
Foreign exchange		15		—		—		—		15
	$	215	$	(138)	$	1	$	18	$	96
Risk management liabilities [b]										
Natural gas	$	124	$	(42)	$	8	$	(11)	$	79
Energy exports		188		(52)		—		—		136
NGL frac spread		2		—		—		—		2
Power		112		(44)		—		—		68
Foreign exchange [c]		—		—		47		—		47
	$	426	$	(138)	$	55	$	(11)	$	332

(a) Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $40 million and risk management assets (non-current) balance of $56 million.

(b) Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $158 million and risk management liabilities (non-current) balance of $174 million.

(c) Includes cross-currency swaps.

As at	December 31, 2023				
	Derivative instruments not designated as hedging instruments		**Derivative instruments designated as hedging instruments**		
	Gross amounts of recognized assets/liabilities	Gross amounts offset in balance sheet	Gross amounts of recognized assets/liabilities	Netting of collateral	Net amounts presented in balance sheet
Risk management assets [a]					
Natural gas	$ 96	$ (44)	$ —	$ —	$ 52
Energy exports	34	(31)	—	—	3
Crude oil and NGLs	4	(6)	—	6	4
NGL frac spread	8	(7)	—	—	1
Power	72	(40)	—	—	32
Foreign exchange	19	—	—	—	19
	$ 233	$ (128)	$ —	$ 6	$ 111
Risk management liabilities [b]					
Natural gas	$ 164	$ (44)	$ 9	$ (31)	$ 98
Energy exports	119	(31)	—	(81)	7
Crude oil and NGLs	6	(6)	—	—	—
NGL frac spread	7	(7)	—	—	—
Power	147	(40)	—	—	107
	$ 443	$ (128)	$ 9	$ (112)	$ 212

(a) Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $54 million and risk management assets (non-current) balance of $57 million.

(b) Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $97 million and risk management liabilities (non-current) balance of $115 million.

Cash Collateral

The following table presents collateral not offset against risk management assets and liabilities:

As at	**September 30, 2024**	December 31, 2023
Collateral posted with counterparties	**$ 9**	$ 12

Any collateral posted that is not offset against risk management assets and liabilities is included in the line item "prepaid expenses and other current assets" in the Consolidated Balance Sheets. Collateral received and not offset against risk management assets and liabilities is included in the line item "customer deposits" in the Consolidated Balance Sheets.

Certain derivative instruments contain contract provisions that require collateral to be posted if the credit rating of AltaGas or certain of its subsidiaries falls below certain levels. At September 30, 2024 and December 31, 2023, AltaGas has not posted any collateral related to its derivative liabilities that contained credit-related contingent features. The following table shows the aggregate fair value of all derivative instruments with credit-related contingent features that are in a liability position, as well as the maximum amount of collateral that would be required if specific credit-risk-related contingent features underlying these agreements were triggered:

As at	**September 30, 2024**	December 31, 2023
Risk management liabilities with credit-risk-contingent features	**$ 162**	$ 158
Maximum potential collateral requirements	**$ 117**	$ 111

Notional Summary

The following table presents the notional quantity outstanding related to the Corporation's commodity contracts:

As at	**September 30, 2024**	December 31, 2023
Natural Gas		
Sales	**262,698,600 GJ**	233,499,133 GJ
Purchases	**566,477,021 GJ**	629,298,784 GJ
Swaps [(a)]	**70,719,623 GJ**	127,829,390 GJ
Crude Oil and NGLs		
Swaps	**314,000 Bbl**	2,399,972 Bbl
Energy Exports		
Purchases	**22,583,291 Bbl**	4,017,118 Bbl
Propane and butane swaps	**76,990,991 Bbl**	76,931,889 Bbl
NGL Frac Spread		
Propane swaps	**304,339 Bbl**	1,040,595 Bbl
Crude oil swaps	**54,648 Bbl**	194,513 Bbl
Natural gas swaps	**3,303,904 GJ**	7,513,045 GJ
Power		
Sales	**5,222,039 MWh**	5,256,989 MWh
Purchases	**5,846,724 MWh**	6,157,474 MWh
Swaps	**27,780,004 MWh**	26,220,739 MWh

(a) Includes approximately 29,668,175 GJ of natural gas swaps at September 30, 2024 designated as hedging instruments that have terms extending until 2029.

Foreign Exchange Risk

AltaGas is exposed to foreign exchange risk as changes in foreign exchange rates may affect the fair value or future cash flows of the Corporation's financial instruments. AltaGas has foreign operations whereby the functional currency is the U.S. dollar. As a result, the Corporation's earnings, cash flows, and OCI are exposed to fluctuations resulting from changes in foreign exchange rates. This risk is partially mitigated to the extent that AltaGas has U.S. dollar-denominated debt outstanding. AltaGas may also enter into foreign exchange forward derivatives to manage the risk of fluctuating cash flows and earnings due to variations in foreign exchange rates as well as to benefit from favorable movements in the rates. Any hedges transacted are subject to risk limits and guidelines and are actively monitored and managed by AltaGas' risk management team to ensure they align with AltaGas' overall financial strategy.

In the third quarter of 2024, AltaGas executed cross-currency swaps totaling US$900 million to manage the risk of fluctuating cash flows and earnings associated with the recently issued US$900 million Subordinated Notes (Note 10) as a result of changes in the Canadian/U.S. dollar foreign exchange rates. The cross-currency swaps will convert the U.S. dollar principal and interest payments of these Subordinated Notes into Canadian dollars and apply an effective annual interest rate of 6.90 percent on the converted Canadian principal amount of approximately $1.2 billion. AltaGas has designated the cross-currency swaps as cash flow hedges as discussed under the *Cash Flow Hedges* section below.

AltaGas may designate its external U.S. dollar-denominated debt or certain U.S. dollar-denominated loans that may give rise to a foreign currency translation gain or loss as a net investment hedge of its U.S. subsidiaries. As at September 30, 2024, AltaGas has designated US$715 million of outstanding loans as a net investment hedge (December 31, 2023 - US$715 million). For the three and nine months ended September 30, 2024, unrealized after-tax gains on the net investment hedge of $12 million and unrealized after-tax losses of $17 million, respectively, were recorded in OCI (three and nine months ended September 30, 2023 - unrealized after-tax losses of $18 million and unrealized after-tax gains of $6 million, respectively).

The following foreign exchange related contracts were outstanding as at September 30, 2024:

	Duration		Fair Value ***($ millions)***
Foreign exchange forward contracts			
Forward USD sales (deliverable)	Less than 1 year		Less than $1 million
Forward USD sales (non-deliverable)	Less than 1 year	$	8
Forward USD sales (non-deliverable)	More than 1 year	$	7
Cross-currency swaps			
Fixed-to-fixed cross-currency swaps	10 years	$	(47)

The following foreign exchange related contracts were outstanding as at December 31, 2023:

Foreign exchange forward contract	**Duration**		**Fair Value** ***($ millions)***
Forward USD sales (deliverable)	Less than 1 year		Less than $1 million
Forward USD sales (non-deliverable)	Less than 1 year	$	10
Forward USD sales (non-deliverable)	More than 1 year	$	9

The following is a summary of gains (losses) on foreign exchange forward contracts recognized in net income:

	Three Months Ended September 30, 2024	Three Months Ended September 30, 2023	**Nine Months Ended September 30, 2024**	Nine Months Ended September 30, 2023
Objective of foreign exchange forward contract	**Gains (losses)**	Gains (losses)	**Gains (losses)**	Gains (losses)
Cash management [(a)]	**$ —**	$ —	**$ (2)**	$ —
Income statement risk management [(b)]	**$ 18**	$ (1)	**$ (3)**	$ (1)

(a) Recorded in the Consolidated Statements of Income (Loss) under the line item "foreign exchange gains (losses)".

(b) Recorded in the Consolidated Statements of Income (Loss) under the line item "revenue".

Cash Flow Hedges

In the normal course of business, WGL Energy Services purchases natural gas indexed to NYMEX Henry Hub to be sold to third party customers. WGL Energy Services' risk management objective and strategy is to protect earnings against the risk of price fluctuations associated with forecasted NYMEX Henry Hub purchases through the use of the NYMEX Henry Hub financial swaps. Beginning April 1, 2023, WGL Energy Services began prospectively designating its NYMEX Henry Hub financial swaps as cash flow hedges in accordance with ASC Topic 815 as it expects that the hedging relationship will be highly effective at achieving offsetting changes in cash flows attributable to the risk being hedged.

For hedging relationships that qualify as highly effective, the change in fair value of the hedging instrument will be recorded to AOCI. Amounts in AOCI will be reclassified into earnings in the same period the hedged forecasted transactions affect earnings, or when non-regulated cost of energy-related sales is recorded. For swaps that settle the month ahead of the physical transaction, the swap impact will be reclassified into earnings in the subsequent month when the associated hedged transaction is recorded into earnings. For storage inventory purchases, such reclassification into earnings will be based on WGL Energy Services' inventory turnover schedules for finished goods in which the hedged natural gas purchases are used. When applicable, the ineffective portion of a commodity cash flow hedge will immediately be recognized in earnings. As at September 30, 2024, the estimated amount of existing losses related to commodity cash flow hedges expected to be reclassified to the income statement in the next 12 months is $4 million.

AltaGas is also exposed to interest rate risk as changes in interest rates may impact future cash flows and fair value of its financial instruments. To manage this risk, the Company may enter into bond forward contract derivatives and designate them as cash flow hedges in accordance with ASC Topic 815, as AltaGas expects that the hedging relationship will be highly effective at achieving offsetting changes in cash flows attributable to the risk being hedged. For hedging relationships that qualify as highly effective, the change in fair value of the hedging instrument will be recorded to AOCI. Amounts in AOCI will be reclassified into earnings in the same period the hedged forecasted transactions affect earnings. When applicable, the ineffective portion of a cash flow hedge will immediately be recognized in earnings. As at September 30, 2024, the estimated amount of existing losses related to the bond forward contract derivative expected to be reclassified to the income statement in the next 12 months is less than $1 million.

As stated above, AltaGas designated US$900 million of cross-currency swaps as cash flow hedges to manage the foreign currency risk associated with its U.S. dollar denominated Subordinated hybrid notes. The cash flow hedges are designated in accordance with ASC Topic 815 as AltaGas expects that the hedging relationship will be highly effective at achieving offsetting changes in cash flows attributable to the risk being hedged. For hedging relationships that qualify as highly effective, the change in fair value of the hedging instrument will be recorded to AOCI. Amounts in AOCI will be reclassified into earnings in the same period the hedged forecasted transactions affect earnings. Any ineffective portion of a cash flow hedge will immediately be recognized in earnings. As at September 30, 2024, the estimated amount of existing losses related to the cross-currency swaps expected to be reclassified to the income statement in the next 12 months is $3 million. Actual amounts reclassified to earnings depends on the movement in foreign exchange rates.

The following is a summary of gains (losses) on designated cash flow hedges recognized in AOCI prior to any reclassifications:

	Three Months Ended September 30, 2024	Three Months Ended September 30, 2023	Nine Months Ended September 30, 2024	Nine Months Ended September 30, 2023
Designated cash flow hedges [(a)]	**Gains (losses)**	Gains	**Gains (losses)**	Gains
Cross-currency swaps	**$ (47)**	$ —	**$ (47)**	$ —
Commodity contracts	**$ (5)**	Less than $1 million	**$ (7)**	Less than $1 million
Bond forward contract	**$ —**	$ —	**$ (7)**	$ —

(a) Amounts presented are after-tax.

The following is a summary of losses on designated cash flow hedges reclassified from AOCI to the income statement:

	Three Months Ended September 30, 2024	Three Months Ended September 30, 2023	Nine Months Ended September 30, 2024	Nine Months Ended September 30, 2023
Designated cash flow hedges [(a)]	**Gains (losses)**	**Gains (losses)**	**Gains (losses)**	**Gains (losses)**
Cross-currency swaps [(b)]	**$ (9)**	$ —	**$ (9)**	$ —
Commodity contracts [(c)]	**$ (2)**	$ —	**$ (9)**	$ —
Bond forward contract [(d)]	**(Less than $1 million)**	$ —	**(Less than $1 million)**	$ —

(a) Amounts presented are after-tax.
(b) Pre-tax amounts were reclassified to the line item "foreign exchange gains (losses)".
(c) Pre-tax amounts were reclassified to the line item "cost of sales".
(d) Pre-tax amounts were reclassified to the line item "interest expense".

Allowance for Credit Losses

The following table presents changes to the allowance for credit losses by segment and major type:

	Three Months Ended September 30, 2024		
	Accounts Receivable	**Contract Assets** [(a)]	**Total**
Utilities			
Balance, beginning of period	**$ 29**	**$ —**	**$ 29**
Adjustments to allowance	**6**	**—**	**6**
Written off	**(11)**	**—**	**(11)**
Recoveries collected	**1**	**—**	**1**
Balance, end of period	**$ 25**	**$ —**	**$ 25**
Midstream			
Balance, beginning of period	**$ 1**	**$ 1**	**$ 2**
Balance, end of period	**$ 1**	**$ 1**	**$ 2**
Total	**$ 26**	**$ 1**	**$ 27**

(a) An allowance for credit loss is assessed quarterly and is recorded based on historical default rates published by external credit rating agencies and a rate associated with the estimated time frame that the contract asset will be billed to the customer.

	Three Months Ended September 30, 2023					
		Accounts Receivable		Contract Assets [a]		Total
Utilities						
Balance, beginning of period	$	37	$	—	$	37
Foreign exchange translation		1		—		1
Adjustments to allowance		2		—		2
Written off		(8)		—		(8)
Recoveries collected		1		—		1
Balance, end of period [b]	$	33	$	—	$	33
Midstream						
Balance, beginning of period	$	2	$	1	$	3
Adjustments to allowance		(1)		—		(1)
Balance, end of period	$	1	$	1	$	2
Total	$	34	$	1	$	35

(a) An allowance for credit loss is assessed quarterly and is recorded based on historical default rates published by external credit rating agencies and a rate associated with the estimated time frame that the contract asset will be billed to the customer.

(b) Includes $2 million recorded to a regulatory asset relating to the impact of COVID-19 on uncollectible accounts as at September 30, 2023.

	Nine Months Ended September 30, 2024					
		Accounts Receivable		**Contract Assets [a]**		**Total**
Utilities						
Balance, beginning of period	**$**	**28**	**$**	**—**	**$**	**28**
Foreign exchange translation		**1**		**—**		**1**
Adjustments to allowance		**21**		**—**		**21**
Written off		**(28)**		**—**		**(28)**
Recoveries collected		**3**		**—**		**3**
Balance, end of period	**$**	**25**	**$**	**—**	**$**	**25**
Midstream						
Balance, beginning of period	**$**	**1**	**$**	**1**	**$**	**2**
Balance, end of period	**$**	**1**	**$**	**1**	**$**	**2**
Total	**$**	**26**	**$**	**1**	**$**	**27**

(a) An allowance for credit loss is assessed quarterly and is recorded based on historical default rates published by external credit rating agencies and a rate associated with the estimated time frame that the contract asset will be billed to the customer.

	Nine Months Ended September 30, 2023		
	Accounts Receivable	Contract Assets [a]	Total
Utilities			
Balance, beginning of period	$ 40	$ —	$ 40
Adjustments to allowance	15	—	15
Written off	(25)	—	(25)
Recoveries collected	3	—	3
Balance, end of period [b]	$ 33	$ —	$ 33
Midstream			
Balance, beginning of period	$ 1	$ 1	$ 2
Balance, end of period	$ 1	$ 1	$ 2
Total	$ 34	$ 1	$ 35

(a) An allowance for credit loss is assessed quarterly and is recorded based on historical default rates published by external credit rating agencies and a rate associated with the estimated time frame that the contract asset will be billed to the customer.

(b) Includes $2 million recorded to a regulatory asset relating to the impact of COVID-19 on uncollectible accounts as at September 30, 2023.

With the exception of accounts receivable which are due in one year or less, AltaGas does not have any past due receivables as at September 30, 2024.

Weather Related Instruments

WGL Energy Services utilizes heating degree day (HDD) instruments from time to time to manage weather and price risks related to its natural gas and electricity sales during the winter heating season. WGL Energy Services also utilizes cooling degree day (CDD) instruments and other instruments to manage weather and price risks related to its electricity sales during the summer cooling season. These instruments cover a portion of estimated revenue or energy-related cost exposure to variations in HDDs or CDDs. For the three and nine months ended September 30, 2024, there were no pre-tax gains or losses recorded related to these instruments (three and nine months ended September 30, 2023 - $nil and pre-tax loss of $8 million, respectively).

14. Leases

Lessor

Certain of AltaGas' revenues are obtained through take-or-pay contracts whereby AltaGas is the lessor in these operating lease arrangements. Minimum lease payments received are amortized over the term of the lease. Revenue from these arrangements have been disclosed in Note 12.

15. Shareholders' Equity

Authorization

AltaGas is authorized to issue an unlimited number of voting common shares. AltaGas is also authorized to issue such number of Preferred Shares in series at any time as have aggregate voting rights either directly or on conversion or exchange that in the aggregate represent less than 50 percent of the voting rights attaching to the then issued and outstanding Common Shares.

Common Shares Issued and Outstanding [(a)]	Number of shares		Amount
January 1, 2023	281,531,833	$	6,761
Shares issued for cash on exercise of options	905,493		19
Shares issued related to Pipestone Acquisition	12,466,437		340
December 31, 2023	294,903,763	$	7,120
Shares issued for cash on exercise of options	2,884,699		57
Issued and outstanding at September 30, 2024	**297,788,462**	**$**	**7,177**

(a) Dividends declared per share for the three and nine months ended September 30, 2024 were approximately $0.30 and $0.89, respectively (three and nine months ended September 30, 2023 - $0.28 and $0.84, respectively).

Preferred Shares

As at	**September 30, 2024**			December 31, 2023		
Issued and Outstanding [(a) (b) (c)]	**Number of shares**		**Amount**	Number of shares		Amount
Series A	**6,746,679**	**$**	**169**	6,746,679	$	169
Series B	**1,253,321**		**31**	1,253,321		31
Series G	**8,000,000**		**200**	6,885,823		172
Series H [(d)]	**—**		**—**	1,114,177		28
Share issuance costs, net of taxes			**(9)**			(9)
	16,000,000	**$**	**391**	16,000,000	$	391

(a) On January 11, 2022, in connection with the offering of the Subordinated Notes, Series 1, AltaGas issued $300 million in Preferred Shares, Series 2022-A, to be held in the AltaGas Hybrid Trust with Computershare Trust Company of Canada acting as a trustee. Refer to Notes 7 and 10 for more details.

(b) On August 17, 2022, in connection with the offering of the Subordinated Notes, Series 2, AltaGas issued $250 million in Preferred Shares, Series 2022-B, to be held in the AltaGas Hybrid Trust with Computershare Trust Company of Canada acting as a trustee. Refer to Notes 7 and 10 for more details.

(c) On November 10, 2023, in connection with the offering of the Subordinated Notes, Series 3, AltaGas issued $200 million in Preferred Shares, Series 2023-A, to be held in the AltaGas Hybrid Trust with Computershare Trust Company of Canada acting as a trustee. Refer to Notes 7 and 10 for more details.

(d) On September 30, 2024, AltaGas converted all of its outstanding Series H Preferred Shares to Series G Preferred Shares.

Share Option Plan

AltaGas has an employee share option plan under which officers, employees, and service providers (as defined by the TSX) are eligible to receive grants. As at September 30, 2024, 7,923,175 shares were listed and reserved for issuance under the plan.

As at September 30, 2024, share options granted under the plan have a term of six years until expiry and vest over no longer than a three-year period.

As at September 30, 2024, the unexpensed fair value of share option compensation cost associated with future periods was $nil (December 31, 2023 - less than $1 million).

The following table summarizes information about the Corporation's share options:

As at	September 30, 2024		December 31, 2023	
	Number of options	Exercise price [(a)]	Number of options	Exercise price [(a)]
Share options outstanding, beginning of period	**5,547,388**	**$ 18.48**	6,958,139	$ 19.28
Exercised	**(2,884,699)**	**17.92**	(905,493)	18.22
Forfeited	**(1,123)**	**23.54**	(83,257)	21.90
Expired	**—**	**—**	(422,001)	31.53
Share options outstanding, end of period	**2,661,566**	**$ 19.08**	5,547,388	$ 18.48
Share options exercisable, end of period	**2,661,566**	**$ 19.08**	4,990,946	$ 18.45

(a) Weighted average.

As at September 30, 2024, the aggregate intrinsic value of the total share options exercisable was $38 million (December 31, 2023 - $47 million), the total intrinsic value of share options outstanding was $38 million (December 31, 2023 - $52 million), and the total intrinsic value of share options exercised was $36 million (December 31, 2023 - $8 million).

The following table summarizes the employee share option plan as at September 30, 2024:

	Options outstanding			Options exercisable		
Price range	Number outstanding	Weighted average exercise price	Weighted average remaining contractual life	Number exercisable	Weighted average exercise price	Weighted average remaining contractual life
$14.52 to $18.00	52,350	$ 14.52	0.21	52,350	$ 14.52	0.21
$18.01 to $25.08	2,608,097	19.17	1.72	2,608,097	19.17	1.72
$25.09 to $26.21	1,119	26.21	2.76	1,119	26.21	2.76
	2,661,566	**$ 19.08**	**1.69**	**2,661,566**	**$ 19.08**	**1.69**

Phantom Unit Plan ("Phantom Plan") and Deferred Share Unit Plan ("DSUP")

AltaGas has a Phantom Plan for employees, executive officers, and directors, which includes restricted units ("RUs") and performance units ("PUs") with vesting periods of up to 36 months from the grant date. In addition, AltaGas has a DSUP, which allows granting of deferred share units ("DSUs") to directors. DSUs granted under the DSUP vest immediately but settlement of the DSUs occur when the individual ceases to be a director.

PUs, RUs, and DSUs *(number of units)*	September 30, 2024	December 31, 2023
Balance, beginning of year	**5,052,918**	4,332,062
Granted	**1,720,411**	2,281,596
Vested and paid out	**(2,128,365)**	(2,047,793)
Forfeited and expired	**(601,189)**	(551,390)
Units in lieu of dividends	**137,835**	210,332
Additional units added by performance factor	**595,757**	828,111
Outstanding, end of period	**4,777,367**	5,052,918

For the three and nine months ended September 30, 2024, the compensation expense recorded for the Phantom Plan and DSUP was $26 million and $60 million, respectively (three and nine months ended September 30, 2023 - $19 million and $44 million, respectively). As at September 30, 2024, the unrecognized compensation expense relating to the remaining vesting period for the Phantom Plan was $50 million (December 31, 2023 - $33 million) and is expected to be recognized over the vesting period.

16. Net Income (Loss) Per Common Share

The following table summarizes the computation of net income (loss) per common share:

	Three Months Ended September 30		Nine Months Ended September 30	
	2024	2023	**2024**	2023
Numerator:				
Net income (loss) applicable to controlling interests	**$ 14**	$ (43)	**$ 388**	$ 548
Less: Preferred share dividends	**(5)**	(7)	**(13)**	(20)
Net income (loss) applicable to common shares	**$ 9**	$ (50)	**$ 375**	$ 528
Denominator:				
(millions of shares)				
Weighted average number of common shares outstanding	**297.6**	281.7	**296.5**	281.7
Dilutive equity instruments [(a)]	**1.2**	—	**1.5**	1.5
Weighted average number of common shares outstanding - diluted	**298.8**	281.7	**298.0**	283.2
Basic net income (loss) per common share	**$ 0.03**	$ (0.18)	**$ 1.26**	$ 1.87
Diluted net income (loss) per common share	**$ 0.03**	$ (0.18)	**$ 1.26**	$ 1.86

(a) Determined using the treasury stock method.

For the three and nine months ended September 30, 2024, there were no share options that had an anti-dilutive impact and were excluded from the diluted net income (loss) per common share calculation (three and nine months ended September 30, 2023, 2.0 million and less than a million share options, respectively).

17. Commitments, Guarantees, and Contingencies

Commitments

AltaGas has long-term natural gas purchase and transportation arrangements, LPG purchase agreements, crude oil and condensate purchase agreements, service agreements, pipeline and storage service contracts, capital commitments, environmental commitments, merger commitments, and operating leases for office space, office equipment, vehicles, rail cars, Very Large Gas Carriers ("VLGCs"), land, storage, aquatic surface use, and other equipment, all of which are transacted at market prices and in the normal course of business. AltaGas' utilities have contracts to purchase natural gas, natural gas transportation and storage services from various suppliers to ensure that there is an adequate supply of natural gas to meet the needs of customers and to minimize exposure to market price fluctuations. In addition, WGL Energy Services also enters into contracts to purchase natural gas and electricity designed to match the duration of its sales commitments, and to secure a margin on estimated sales over the terms of existing sales contracts. Please refer to Note 29 of the 2023 Annual Consolidated Financial Statements for further details regarding AltaGas' commitments.

At September 30, 2024, AltaGas has US$168 million in future undiscounted cash flows associated with operating leases not yet commenced. The leases are for the use of two VLGCs, which are expected to commence in the first half of 2026 and the second half of 2026. The lessor is primarily involved in the design and construction of the VLGCs.

Guarantees

AltaGas has guaranteed payments primarily for certain commitments on behalf of some of its subsidiaries. As at September 30, 2024, AltaGas had no guarantees issued on behalf of external parties.

Contingencies

AltaGas and its subsidiaries are subject to various legal claims and actions arising in the normal course of business. While the final outcome of such legal claims and actions cannot be predicted with certainty, the Corporation does not believe that the resolution of such claims and actions will have a material impact on the Corporation's consolidated financial position or results of operations.

<u>Merger Commitments - District of Columbia</u>

On August 9, 2023, the Public Service Commission of the District of Columbia ("PSC of DC") determined that AltaGas had failed to fulfill Term No. 5 Commitment of the PSC of DC's merger approval order related to the June 2018 merger of AltaGas, WGL, and Washington Gas. On reconsideration, the PSC of DC confirmed, in relevant part, that it had credited AltaGas with causing the development of 2.4 MW of Tier one renewable resources by the July 6, 2023 deadline, and that the Company had breached its Term No. 5 Commitment only for the remaining 7.6 MW. As directed by the PSC of DC, AltaGas, the District of Columbia Government ("DCG"), and the District of Columbia Office of People's Counsel ("DC OPC") conducted negotiations in good faith to reach agreement on a penalty but were unable to reach agreement. Thereafter, AltaGas confirmed that it will specifically perform its Term No. 5 obligations by continuing to cause the development of the remaining 7.6 MW of solar renewable energy. On March 8, 2024, the PSC of DC issued an order to show cause why the penalty amount should not be the maximum allowed under D.C. Code §34-708 (US$5,000/day). On June 14, 2024, AltaGas and DCG jointly requested that the PSC of DC allow sixty (60) days for the parties to negotiate a settlement in the form of a consent decree or, if no agreement is reached, to file a report on the status of the negotiations. AltaGas and DCG have kept the PSC of DC appraised of the status of the negotiations and, on October 8, 2024, filed a Proposed Consent Decree for PSC of DC approval. As at September 30, 2024, AltaGas believes that the civil penalty is probable, and based upon reasonable estimates, has recorded an accrued liability of approximately US$2.1 million.

18. Pension Plans and Retiree Benefits

The costs of the defined benefit and post-retirement benefit plans are based on Management's estimate of the future rate of return on the fair value of pension plan assets, salary escalations, mortality rates, and other factors affecting the payment of future benefits. Additional information relating to the retirement benefit plans is provided in Note 28 of the 2023 Annual Consolidated Financial Statements.

Rabbi trusts of $7 million as at September 30, 2024 have been funded to satisfy the employee benefit obligations associated with WGL's various pension plans (December 31, 2023 - $9 million). These balances are included in "prepaid expenses and other current assets" and "long-term investments and other assets" in the Consolidated Balance Sheets.

In the third quarter of 2024, WGL recognized a settlement credit associated with the partial settlement of its post-retirement benefit plan under the line item "other income" for the three and nine months ended September 30, 2024. This was a result of the purchase of a medical health reimbursement arrangement annuity and a guaranteed life insurance funding account, which transferred all of the future financial and administrative responsibilities to the insurance carriers effective August 2024.

In 2024, WGL elected to change its calculation related to minimum funding requirements for one of its DB pension plans resulting in a decrease of estimated benefit contributions for 2024 by approximately US$8 million (CAD$11 million).

The net pension expense by plan for the period was as follows:

	Three Months Ended September 30, 2024					
	Canada		United States		Total	
	Defined Benefit	Post-retirement Benefits	Defined Benefit	Post-retirement Benefits	Defined Benefit	Post-retirement Benefits
Current service cost [(a)]	$ —	$ —	$ 3	$ 1	$ 3	$ 1
Interest cost [(b)]	1	—	17	3	18	3
Expected return on plan assets [(b)]	—	—	(21)	(13)	(21)	(13)
Amortization of past service credit [(b)]	—	—	—	(5)	—	(5)
Amortization of net actuarial gain [(b)]	—	—	—	(1)	—	(1)
Plan settlements [(b) (c)]	—	—	—	(65)	—	(65)
Other [(b)]	—	—	—	3	—	3
Net benefit cost (income) recognized	$ 1	$ —	$ (1)	$ (77)	$ —	$ (77)

(a) Recorded under the line item "operating and administrative" expenses on the Consolidated Statements of Income (Loss).
(b) Recorded under the line item "other income" on the Consolidated Statements of Income (Loss).
(c) Relates to the partial settlement of WGL's post-retirement benefit plan as discussed above.

	Three Months Ended September 30, 2023					
	Canada		United States		Total	
	Defined Benefit	Post-retirement Benefits	Defined Benefit	Post-retirement Benefits	Defined Benefit	Post-retirement Benefits
Current service cost [(a)]	$ 2	$ —	$ 3	$ 2	$ 5	$ 2
Interest cost [(b)]	—	—	17	5	17	5
Expected return on plan assets [(b)]	—	—	(19)	(12)	(19)	(12)
Amortization of past service credit [(b)]	—	—	—	(5)	—	(5)
Amortization of net actuarial gain [(b)]	—	—	—	(1)	—	(1)
Net benefit cost (income) recognized	$ 2	$ —	$ 1	$ (11)	$ 3	$ (11)

(a) Recorded under the line item "operating and administrative" expenses on the Consolidated Statements of Income (Loss).
(b) Recorded under the line item "other income" on the Consolidated Statements of Income (Loss).

	Nine Months Ended September 30, 2024					
	Canada		United States		Total	
	Defined Benefit	Post-retirement Benefits	Defined Benefit	Post-retirement Benefits	Defined Benefit	Post-retirement Benefits
Current service cost [(a)]	$ 1	$ —	$ 9	$ 5	$ 10	$ 5
Interest cost [(b)]	1	—	51	12	52	12
Expected return on plan assets [(b)]	—	—	(62)	(39)	(62)	(39)
Amortization of past service credit [(b)]	—	—	—	(15)	—	(15)
Amortization of net actuarial gain [(b)]	—	—	—	(4)	—	(4)
Plan settlements [(b) (c)]	—	—	—	(65)	—	(65)
Other [(b)]	—	—	—	3	—	3
Net benefit cost (income) recognized	$ 2	$ —	$ (2)	$ (103)	$ —	$ (103)

(a) Recorded under the line item "operating and administrative" expenses on the Consolidated Statements of Income (Loss).
(b) Recorded under the line item "other income" on the Consolidated Statements of Income (Loss).
(c) Relates to the partial settlement of WGL's post-retirement benefit plan as discussed above.

	Nine Months Ended September 30, 2023					
	Canada		United States		Total	
	Defined Benefit	Post-retirement Benefits	Defined Benefit	Post-retirement Benefits	Defined Benefit	Post-retirement Benefits
Current service cost [(a)]	$ 4	$ —	$ 9	$ 5	$ 13	$ 5
Interest cost [(b)]	1	—	52	14	53	14
Expected return on plan assets [(b)]	—	—	(59)	(36)	(59)	(36)
Amortization of past service credit [(b)]	—	—	—	(15)	—	(15)
Amortization of net actuarial gain [(b)]	—	—	—	(3)	—	(3)
Plan settlements [(b) (c) (d)]	2	—	4	(2)	6	(2)
Net benefit cost (income) recognized	$ 7	$ —	$ 6	$ (37)	$ 13	$ (37)

(a) Recorded under the line item "operating and administrative" expenses on the Consolidated Statements of Income (Loss).
(b) Recorded under the line item "other income" on the Consolidated Statements of Income (Loss).
(c) Pursuant to the Alaska Utilities Disposition, the ENSTAR pension plans were divested and resulted in a curtailment gain of less than $1 million and a net settlement charge of $2 million.
(d) Includes the wind-up of the Canadian defined benefit pension plan.

19. Income Taxes

On June 20, 2024, Bills C-59 and C-69, which include the Excessive Interest and Financing Expenses Limitation and Canada's Global Minimum Tax Act were enacted in Canada. As at September 30, 2024, the enactment of these bills did not have a material impact on AltaGas consolidated financial statements.

20. Supplemental Cash Flow Information

The following table details the changes in operating assets and liabilities from operating activities:

	Three Months Ended September 30		Nine Months Ended September 30	
	2024	2023	**2024**	2023
Source (use) of cash:				
Accounts receivable	**$ 32**	$ (273)	**$ 466**	$ 537
Inventory	**14**	(100)	**168**	245
Risk management assets - current	**(9)**	(34)	**42**	(18)
Prepaid expenses and other current assets	**18**	13	**43**	25
Regulatory assets - current	**14**	6	**(21)**	(32)
Accounts payable and accrued liabilities	**(107)**	267	**(307)**	(296)
Customer deposits	**22**	22	**(1)**	7
Regulatory liabilities - current	**(3)**	1	**(55)**	(128)
Other current liabilities	**16**	11	**(9)**	(28)
Other operating assets and liabilities	**(61)**	(37)	**(25)**	(14)
Changes in operating assets and liabilities	**$ (64)**	$ (124)	**$ 301**	$ 298

The following table details the changes in non-cash investing and financing activities:

	Three Months Ended September 30		Nine Months Ended September 30	
	2024	2023	**2024**	2023
Decrease (increase) of balance:				
Exercise of stock options	**$ 1**	$ —	**$ 6**	$ —
Net right-of-use assets obtained in exchange for new operating lease liabilities	**$ (13)**	$ (31)	**$ (155)**	$ (52)
Net right-of-use assets obtained in exchange for new finance lease liabilities	**$ (2)**	$ (4)	**$ (16)**	$ (14)
Capital expenditures included in accounts payable and accrued liabilities	**$ (23)**	$ (12)	**$ (20)**	$ 23
Contributions from non-controlling interests to subsidiaries included in accounts receivable	**$ 12**	$ —	**$ (19)**	$ —

The following table is a reconciliation of cash and cash equivalents and restricted cash balances:

As at September 30	**2024**	2023
Cash and cash equivalents	**$ 772**	$ 43
Restricted cash included in prepaid expenses and other current assets [(a)]	**3**	3
Restricted cash included in long-term investments and other assets [(a)]	**4**	6
Cash, cash equivalents, and restricted cash per Consolidated Statements of Cash Flows	**$ 779**	$ 52

(a) The restricted cash balances included in "prepaid expenses and other current assets" and "long-term investments and other assets" relate to Rabbi trusts associated with WGL's pension plans (Note 18).

21. Seasonality

The Utilities business is highly seasonal with the majority of natural gas deliveries occurring during the winter heating season. Gas sales increase during the winter resulting in stronger first and fourth quarter results and weaker second and third quarter results. The retail business within the Utilities segment is also seasonal, with larger amounts of electricity being sold in the summer and peak winter months and larger amounts of natural gas being sold in the winter months.

22. Segmented Information

AltaGas owns and operates a portfolio of assets and services used to move energy from the source to the end-user. The following describes the Corporation's reportable segments:

Utilities	▪ rate-regulated natural gas distribution assets in Michigan, the District of Columbia, Maryland, and Virginia; ▪ rate-regulated natural gas storage in the United States; and ▪ sale of natural gas and power to residential, commercial, and industrial customers in the District of Columbia, Maryland, Virginia, Delaware, Pennsylvania, and Ohio.
Midstream	▪ NGL processing and extraction plants; ▪ natural gas storage facilities; ▪ LPG export terminals; ▪ transmission pipelines to transport natural gas and NGLs; ▪ natural gas gathering lines and field processing facilities; ▪ purchase and sale of natural gas; ▪ natural gas and NGL marketing; ▪ marketing, storage and distribution of wellsite fluids and fuel, crude oil and condensate diluents; and ▪ interest in a regulated gas pipeline in the Marcellus/Utica gas formation.
Corporate/ Other	▪ the cost of providing corporate services, financing and general corporate overhead, corporate assets, financing other segments and the effects of changes in the fair value of certain risk management contracts; and ▪ a small portfolio of power assets.

The following table provides a reconciliation of segment revenue to the disaggregated revenue table disclosed under Note 12:

	Three Months Ended September 30, 2024			
	Utilities	**Midstream**	**Corporate/ Other**	**Total**
External revenue *(note 12)*	**$ 839**	**$ 1,887**	**$ 33**	**$ 2,759**
Segment revenue	**$ 839**	**$ 1,887**	**$ 33**	**$ 2,759**

	Three Months Ended September 30, 2023			
	Utilities	Midstream	Corporate/ Other	Total
External revenue *(note 12)*	$ 767	$ 2,237	$ 26	$ 3,030
Segment revenue	$ 767	$ 2,237	$ 26	$ 3,030

	Nine Months Ended September 30, 2024			
	Utilities	**Midstream**	**Corporate/ Other**	**Total**
External revenue *(note 12)*	**$ 3,241**	**$ 5,881**	**$ 67**	**$ 9,189**
Segment revenue	**$ 3,241**	**$ 5,881**	**$ 67**	**$ 9,189**

		Nine Months Ended September 30, 2023			
		Utilities	Midstream	Corporate/ Other	Total
External revenue *(note 12)*	$	3,539 $	6,098 $	72 $	9,709
Segment revenue	$	3,539 $	6,098 $	72 $	9,709

The following tables show the composition by segment:

		Three Months Ended September 30, 2024			
		Utilities	**Midstream**	**Corporate/ Other**	**Total**
Segment revenue *(note 12)*	**$**	**839 $**	**1,887 $**	**33 $**	**2,759**
Cost of sales		**(568)**	**(1,606)**	**(12)**	**(2,186)**
Operating and administrative		**(253)**	**(150)**	**(30)**	**(433)**
Accretion expenses		**(1)**	**(1)**	**—**	**(2)**
Depreciation and amortization		**(74)**	**(38)**	**(7)**	**(119)**
Income from equity investments *(note 8)*		**—**	**16**	**—**	**16**
Other income		**81**	**15**	**—**	**96**
Foreign exchange losses		**—**	**—**	**(1)**	**(1)**
Interest expense		**—**	**—**	**(110)**	**(110)**
Income (loss) before income taxes	**$**	**24 $**	**123 $**	**(127) $**	**20**
Net additions to:					
Property, plant and equipment [(a)]	**$**	**187 $**	**182 $**	**3 $**	**372**
Intangible assets [(a)]	**$**	**— $**	**2 $**	**— $**	**2**

(a) Net additions to property, plant and equipment, and intangible assets may not agree to changes reflected in the Consolidated Statements of Cash Flows due to classification of business acquisition and foreign exchange changes on U.S. assets.

		Three Months Ended September 30, 2023			
		Utilities	Midstream	Corporate/ Other	Total
Segment revenue *(note 12)*	$	767 $	2,237 $	26 $	3,030
Cost of sales		(477)	(2,057)	(9)	(2,543)
Operating and administrative		(254)	(108)	(17)	(379)
Accretion expenses		—	(3)	—	(3)
Depreciation and amortization		(70)	(31)	(8)	(109)
Income from equity investments *(note 8)*		1	20	—	21
Other income		17	3	1	21
Foreign exchange gains		—	—	6	6
Interest expense		—	—	(95)	(95)
Income (loss) before income taxes	$	(16) $	61 $	(96) $	(51)
Net additions to:					
Property, plant and equipment [(a)]	$	204 $	49 $	1 $	254
Intangible assets [(a)]	$	— $	1 $	— $	1

(a) Net additions to property, plant and equipment, and intangible assets may not agree to changes reflected in the Consolidated Statements of Cash Flows due to classification of business acquisition and foreign exchange changes on U.S. assets.

	Nine Months Ended September 30, 2024			
	Utilities	**Midstream**	**Corporate / Other**	**Total**
Segment revenue *(note 12)*	**$ 3,241**	**$ 5,881**	**$ 67**	**$ 9,189**
Cost of sales	**(1,905)**	**(4,924)**	**(27)**	**(6,856)**
Operating and administrative	**(792)**	**(445)**	**(89)**	**(1,326)**
Accretion expenses	**(1)**	**(3)**	**—**	**(4)**
Depreciation and amortization	**(218)**	**(112)**	**(22)**	**(352)**
Income from equity investments *(note 8)*	**2**	**43**	**—**	**45**
Other income	**114**	**25**	**2**	**141**
Foreign exchange gains	**—**	**—**	**5**	**5**
Interest expense	**—**	**—**	**(327)**	**(327)**
Income (loss) before income taxes	**$ 441**	**$ 465**	**$ (391)**	**$ 515**
Net additions to:				
Property, plant and equipment [(a)]	**$ 544**	**$ 350**	**$ 35**	**$ 929**
Intangible assets [(a)]	**$ —**	**$ 4**	**$ —**	**$ 4**

(a) Net additions to property, plant and equipment, and intangible assets may not agree to changes reflected in the Consolidated Statements of Cash Flows due to classification of business acquisition and foreign exchange changes on U.S. assets.

	Nine Months Ended September 30, 2023			
	Utilities	Midstream	Corporate/ Other	Total
Segment revenue *(note 12)*	$ 3,539	$ 6,098	$ 72	$ 9,709
Cost of sales	(2,239)	(5,342)	(16)	(7,597)
Operating and administrative	(770)	(311)	(71)	(1,152)
Accretion expenses	—	(8)	—	(8)
Depreciation and amortization	(217)	(91)	(23)	(331)
Income from equity investments *(note 8)*	2	30	—	32
Other income	364	5	16	385
Foreign exchange gains	—	—	6	6
Interest expense	—	—	(293)	(293)
Income (loss) before income taxes	$ 679	$ 381	$ (309)	$ 751
Net additions (reductions) to:				
Property, plant and equipment [(a)]	$ (505)	$ 87	$ (8)	$ (426)
Intangible assets [(a)]	$ —	$ 4	$ 1	$ 5

(a) Net additions to property, plant and equipment, and intangible assets may not agree to changes reflected in the Consolidated Statements of Cash Flows due to classification of business acquisition and foreign exchange changes on U.S. assets.

The following table shows goodwill and total assets by segment:

	Utilities	**Midstream**	**Corporate/ Other**	**Total**
As at September 30, 2024				
Goodwill *(note 5)*	**$ 3,705**	**$ 1,662**	**$ —**	**$ 5,367**
Segmented assets	**$ 15,507**	**$ 7,955**	**$ 1,286**	**$ 24,748**
As at December 31, 2023				
Goodwill *(note 5)*	$ 3,630	$ 1,640	$ —	$ 5,270
Segmented assets	$ 15,272	$ 7,578	$ 621	$ 23,471

23. Subsequent Events

On October 1, 2024, Washington Gas executed a note purchase agreement to issue US$200 million in private placement notes. US$100 million of these notes were issued on October 1, 2024 at 5.40 percent with a maturity date of October 1, 2054 and the remaining US$100 million will be issued on April 1, 2025 at 4.84 percent with a maturity date of April 1, 2035. The proceeds will be used for general corporate purposes.

Subsequent events have been reviewed through October 30, 2024, the date on which these unaudited condensed interim Consolidated Financial Statements were issued.

SUPPLEMENTAL QUARTERLY OPERATING INFORMATION

	Q3-24	Q2-24	Q1-24	Q4-23	Q3-23
OPERATING HIGHLIGHTS					
UTILITIES					
Natural gas deliveries - end use (Bcf) (1)	**8.9**	14.5	54.5	48.3	8.5
Natural gas deliveries - transportation (Bcf) (1)	**20.7**	20.2	35.1	30.5	19.9
Service sites (thousands) (2)	**1,560**	1,560	1,562	1,560	1,553
Degree day variance from normal - SEMCO (Michigan) (%) (3)	**(57.4)**	(29.0)	(13.8)	(9.8)	(19.4)
Degree day variance from normal - Washington Gas (D.C.) (%) (3) (4) (5)	**(100.0)**	(31.6)	(15.6)	(9.2)	—
WGL retail energy marketing - gas sales volumes (Mmcf)	**8,179**	9,664	23,810	16,863	8,550
WGL retail energy marketing - electricity sales volumes (GWh)	**4,344**	3,714	3,542	3,518	4,134
MIDSTREAM					
LPG export volumes (Bbls/d) (6)	**128,272**	123,285	115,108	90,996	118,213
Total inlet gas processed (Mmcf/d) (6)	**1,303**	1,420	1,401	1,312	1,182
Extracted ethane volumes (Bbls/d) (6)	**20,314**	19,618	20,369	23,879	25,501
Extracted NGL volumes (Bbls/d) (6) (7) (8)	**46,707**	47,054	48,272	36,138	36,070
Fractionation volumes (Bbls/d) (6) (9)	**43,445**	43,421	41,072	38,150	39,699
Frac spread - realized ($/Bbl) (6) (10)	**24.70**	25.32	25.25	23.13	23.75
Frac spread - average spot price ($/Bbl) (6) (11)	**30.39**	29.61	25.45	20.55	21.31
Propane Far East Index ("FEI") to Mont Belvieu spread (US$/Bbl) (6) (12)	**13.28**	14.52	14.06	26.44	21.30
Butane FEI to Mont Belvieu spread (US$/Bbl) (6) (13)	**17.44**	16.17	13.87	27.74	22.07

(1) Bcf is one billion cubic feet.

(2) Service sites reflect all of the service sites of the utilities, including transportation and non-regulated business lines.

(3) A degree day is a measure of coldness determined daily as the number of degrees the average temperature during the day in question is below 65 degrees Fahrenheit. Degree days for a particular period are determined by adding the degree days incurred during each day of the period. Normal degree days for a particular period are the average of degree days during the prior 15 years for SEMCO Gas and during the prior 30 years for Washington Gas.

(4) In certain of Washington Gas' jurisdictions (Virginia and Maryland) there are billing mechanisms in place which are designed to eliminate the effects of variance in customer usage caused by weather and other factors such as conservation. In the District of Columbia, there is no weather normalization billing mechanism nor does Washington Gas hedge to offset the effects of weather. As a result, colder or warmer weather will result in variances to financial results.

(5) The -100 percent degree day variance for Washington Gas in the third quarter of 2024 is a result of there being 12 normal degree days in the third quarter, compared to nil actual degree days. Given that the normal degree days in the third quarter are so low compared to other quarters, any change causes a large variance when shown as a percentage.

(6) Average for the period.

(7) NGL volumes refer to propane, butane and condensate.

(8) Reflects the revision of volumes in the first quarter of 2024.

(9) Fractionation volumes include NGL mix volumes processed.

(10) Realized frac spread or NGL margin, expressed in dollars per barrel of NGL, is derived from sales recorded by the segment during the period for frac spread exposed volumes plus the settlement value of frac hedges settled in the period less extraction premiums, divided by the total frac exposed volumes produced during the period.

(11) Average spot frac spread or NGL margin, expressed in dollars per barrel of NGL, is indicative of the average sales price that AltaGas receives for propane, butane and condensate less extraction premiums, before accounting for hedges, divided by the respective frac spread exposed volumes for the period.

(12) Average propane price spread between FEI and Mont Belvieu TET commercial index.

(13) Average butane price spread between FEI and Mont Belvieu TET commercial index.

OTHER INFORMATION

DEFINITIONS

Bbls/d	barrels per day
Bcf	billion cubic feet
Dth	dekatherm
GJ	gigajoule
GWh	gigawatt-hour
MBbl	thousands of barrels
Mmcf	million cubic feet
Mmcf/d	million cubic feet per day
MW	megawatt
MWh	megawatt-hour
US$	United States dollar

ABOUT ALTAGAS

AltaGas is a leading North American energy infrastructure company that connects NGLs and natural gas to domestic and global markets. The Company operates a diversified, lower-risk, high-growth Utilities and Midstream business that is focused on delivering resilient and durable value for its stakeholders.

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AOBA (B)

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF	)	
	)	
The Application of Washington Gas Light	)	
Company for Authority to Increase Existing	)	**Formal Case No. 1180**
Rates and Charges for Gas Service	)	

VOLUME II OF II: DIRECT TESTIMONY OF AOBA WITNESS
BRUCE R. OLIVER

January 24, 2025

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DIRECT TESTIMONY OF BRUCE R. OLIVER
DC PSC Formal Case No. 1180

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DIRECT TESTIMONY OF BRUCE R. OLIVER
DC PSC Formal Case No. 1180

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Exhibit AOBA (B)-2:	**Analysis of WG Peak Day Estimates for Base Gas and Weather Sensitive Gas - FC 1169 vs FC 1180**
Exhibit AOBA (B)-3:	**Development of AOBA Proposed Charges for C&I and GMA Customers**

ATTACHMENT A: Resume of Bruce R. Oliver

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bruce R. Oliver. My business address is 7103 Laketree Drive Fairfax Station, Virginia, 22039.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am employed by Revilo Hill Associates, Inc., and serve as President of the firm, and I manage the firm's business and consulting activities. I direct the preparation and presentation of economic, utility planning, and policy analyses for clients.

Q. ON WHOSE BEHALF DO YOU APPEAR IN THIS PROCEEDING?

A. I appear on behalf of the Apartment and Office Building Association of Metropolitan Washington (AOBA).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony in this proceeding addresses issues relating to the Washington Gas Light Company (“Washington Gas,” "WG" or "the Company")[1] Application for authority to increase its existing rates and charges for gas service. This testimony

[1] To avoid confusion between Washington Gas Light Company and other affiliates under the WGL Holdings umbrella, this testimony uses the acronym “WG” to refer to Washington Gas. The acronym “WGL” is reserved for WGL Holdings and affiliates that include the acronym in their names.

responds to portions of the pre-filed Direct testimony and exhibits of witnesses D'Ascendis, Tuoriniemi, Smith, Raab, and Lawson.

Q. PLEASE SUMMARIZE YOUR EXPERIENCE AND QUALIFICATIONS.

A. I am an economist specializing in the areas of utility rates, energy, and regulatory policy matters. I have nearly 50 years of experience in the analysis of energy and utility policy issues. That experience includes employment in management positions in the rate departments of two major utilities (the Pacific Gas and Electric Company and the Potomac Electric Power Company), as well as service in management and senior staff positions for three firms engaged in energy, utility and public policy consulting. Those firms include: Revilo Hill Associates, Inc., the Resource Dynamics Corporation, and ICF Incorporated.

As a consultant, I have served a diverse group of clients on issues encompassing a wide range of energy and utility related activities. My clients have included state regulatory commissions, utilities, state Attorneys General, state-funded consumer advocacy groups, municipal governments, hospitals and universities, federal agencies, commercial and industrial energy users, suppliers of equipment and services to utility markets, residential consumer intervenors, the Electric Power Research Institute (EPRI), and the World Bank. Projects for those clients have included work on gas, electric, water, and wastewater utility regulatory proceedings, as well as analyses and forecasts of supply, demand, and prices for utility and non-utility energy markets. I have also assisted a number of commercial, institutional, and industrial energy users in the negotiation of a wide range of energy service contracts, including contracts for the procurement of competitive electricity and natural gas services.

To date, I have filed more than 450 separate pieces of testimony in over 300 proceedings before regulatory commissions in 26 jurisdictions. The regulatory jurisdictions in which I have testified include: the states of Pennsylvania, New York, New Jersey, Maryland, Delaware, Virginia, North Carolina, Rhode Island, Vermont, Connecticut, Massachusetts, Ohio, Illinois, Wisconsin, South Dakota, Arizona, New Mexico, Utah, and California, as well as the District of Columbia, Guam, the Virgin Islands, the City of Philadelphia, the Provence of Alberta, Canada, and the U.S. Federal Energy Regulatory Commission (FERC). My testimonies in those jurisdictions have addressed such topics as industry restructuring, utility mergers and acquisitions, divestiture of generation assets, sighting of energy facilities, utility revenue requirements, costs of capital, capacity planning, cost of service allocations, rate design, rate unbundling, incentive ratemaking, revenue decoupling, capacity expansion planning, demand-side management, energy conservation, weather normalization of usage, cash working capital requirements, contracts for non-tariff service provided to large energy users, natural gas procurement practices, gas cost and fuel cost adjustment mechanisms, gas transportation service, interruptible service, natural gas processing, economic development rates, load research, load forecasting, weather normalization, metering, and fuel pricing issues. I have also testified before legislative committees in Virginia, Maryland, and the District of Columbia.

Q. HAVE YOU PREVIOUSLY APPEARED BEFORE THIS COMMISSION?

A. Yes, I have appeared before this Commission in a number of prior gas and electric rate proceedings. The prior WG proceedings before this Commission in which I have testified include: Formal Case Nos. 787, 840, 845, 890, 922, 934, 989, 1016, 1054, 1079, 1093, 1115, 1137, 1142, 1154, 1162 and 1169.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN PROCEEDINGS IN OTHER JURISDICTIONS RELATING TO WASHINGTON GAS LIGHT COMPANY?

A. Yes, I have testified in numerous Washington Gas Light Company cases before the Maryland Public Service Commission (MDPSC) and the Virginia State Corporation Commission (VASCC). The Washington Gas Light Company proceedings in Maryland in which I have testified include: Case Nos. 7649, 8060, 8119, 8191, 8545, 8819, 8920 (Phases I and II), 8959, 8991, 9104, 9158, 9267, 9322, 9335, 9433, 9449, 9481, 9605, 9651 and 9704. The WG proceedings in Virginia in which I have submitted testimony include: Case Nos. PUE 830008, PUE 830029, PUE 880024, PUE 900016, PUE 910047, PUE 920041, PUE 940031,

PUE 960296, PUE 980812, PUE 000584, PUE 2002-00364, PUE 2003-00603, PUE 2005-00010, PUE 2006-00059, PUE 2010-00139, PUE-2016-00001, and PUR 2018-00080. In total, I have participated in more than 50 Washington Gas rate proceedings in DC, MD, and VA.

Q. WERE THIS TESTIMONY AND ACCOMPANYING EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION AND CONTROL?

A. Yes, they were.

II. OVERVIEW

Q. WHAT IS YOUR OVERALL ASSESSMENT OF THE COMPANY'S PROPOSED RATES AND CHARGES FOR GAS SERVICE IN THE DISTICT OF COLUMBIA IN THIS PROCEEDING?

A. The sheer magnitude of Washington Gas' revenue increase request in this proceeding is a concern for all of the Company's gas customers in the District of Columbia. As noted in the Direct Testimony of WG witness Lawson, the Company's proposed system average increase in distribution revenues is **30.29%**.[2] That is far in excess of any measure of inflation-related cost increases that District residents and business are experiencing.

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[2] Exhibit WG (O), page 4, lines 9-11.

The Commission must also recognize that the declines in gas commodity costs experienced in the last decade, cannot be expected going forward. As a result, the Commission cannot presume that the large increases in rate burdens that WG's requested base rate revenue increase will impose will be offset by declines in gas commodity costs. WG's overall service requirements are not growing significantly, if at all, and the Company's large proposed rate increase can only be expected to stimulate more conservation and/or use of other fuels (e.g., electrification alternatives). In this context, it is imperative that this Commission carefully scrutinize both the components of the Company's requested revenue increase and the manner in which Washington Gas proposes to recover its requested revenue increase from its District of Columbia customers.

The problems associated with WG's rate proposals are compounded by an inappropriate and distorted assessment of Normal Weather therm use by rate classification. As I will explain further herein, the adjustments to annual therm use that Washington Gas computes in its "Normal Weather Study" are more greatly influenced by adjustments to **non-weather-sensitive** gas use than by adjustments to weather sensitive gas use. In Formal Case No. 1137, Order No. 18712, this Commission accepted WG's weather normalization methodology, in part, based on its perception that "… *use of the regression methodology for the Base Gas factor … should provide a more consistent calculation of Base Gas from rate case* *to rate case*."[3] That is not what we now observe. Rather, particularly for the Company's C&I Heating/Cooling classes, the Company's Weather Normalization Study produces large case-to-case changes in **Base** (**non-weather-sensitive**) **Gas Use**. Moreover, those inexplicably large changes in estimated Base Gas Use flow through the Company's entire rate filing, distorting its class cost of service analyses, its rate designs, and its overall revenue requirement determinations.

Although WG's witnesses discuss cost-based ratemaking concepts, the Company's actual application of cost-based ratemaking principles is quite limited. WG provides little direct support for the cost basis of its proposed rates and charges. Given the magnitude of the Company's overall revenue increase request, it is understandable that limits are placed on the size of increases proposed for individual rate classes. However, the Company provides no assessment of the extent to which its proposed charges for each rate class correspond to its customer, demand, and commodity-related unit costs. In essence, it appears that cost-based ratemaking has been relegated to, at best, a tertiary level of importance. Rather than allowing the distorting affects of WG's estimates of non-weather-sensitive gas use to distort its class cost of service analyses and rate designs, this testimony recommends that the Commission consolidate the rate structures of its C&I and GMA rate classes and adopt a **single set** of charges in this proceeding for each of those broader rate classes.

[3] Formal Case No. 1137, Order No. 18712, issued March 3, 2017, page 67, paragraph 186.

WG's rate structure proposals in this proceeding also include a proposed WNA ("Weather Normalization Adjustment"). Although the Company has proposed some form of revenue decoupling/weather normalization in each of its base rate cases before this Commission over roughly the last decade, the Company's WNA proposal in this proceeding is presented as strictly a mechanism designed to adjust for the affects of weather and presents a mechanism that provides for just seasonal consideration of the impacts of weather on the Company's revenue collections. While the Company's efforts to refine its WNA proposal are appreciated, that proposal still engenders some problems and concerns that need to be addressed.

III. DISCUSSION OF ISSUES

Q. HOW IS YOUR DISCUSSION OF ISSUES RELATING TO WG'S DIRECT TESTIMONY AND SCHEDULES IN THIS PROCEEDING ORGANIZED?

A. My Discussion of Issues is presented in three sections:

Section A WG's Normal Weather Study

Section B WG's Class Cost of Service Analyses

Section C Rate Structure Issues

A. WG'S NORMAL WEATHER STUDY

Q. HAVE YOU REVIEWED THE NORMAL WEATHER STUDY THAT WITNESS RAAB PRESENTS ON BEHALF OF WASHINGTON GAS IN THIS PROCEEDING?

A. I have. I have also compared that study, its methods, and results with the Normal Weather Study the Company presented in Formal Case No. 1169.

Q. WHAT IS THE IMPORTANCE OF THE COMPANY'S NORMAL WEATHER STUDY IN THIS PROCEEDING?

A. The estimates of normalized therm use that Washington Gas witness Raab develops have direct and extensive impacts on the Company's entire filing, including WG's representation of its adjusted test year revenues, the Company's estimated cost of gas revenues, WG's allocations of its distribution service costs among rate classes, the calculation of class rates of return, and the design of charges to collect the Company's requested revenue requirement.

Q. DO YOU AGREE THAT WEATHER NORMALIZATION OF GAS USE FOR RATE MAKING PURPOSES IS APPROPRIATE?

A. Weather normalizations concepts are broadly used in the natural gas industry. As this Commission recognized in Order No. 21939, weather normalization of gas use is intended to ensure that throughput[4] and revenues used in the development of rates are reasonably reflective of conditions that can be expected during a future rate-effective period.[5] However, the methods used by gas utilities to weather normalize gas use volumes are not uniform across the industry. The manner in which a utility estimates normal weather gas use can have significant impacts on revenue requirements and rate design determinations. Thus, given the influence that modelling methods and assumptions can have on the results of weather normalization analyses, it is inappropriate for the Commission to provide the Company broad discretion[6] with the data, methods, and assumptions used to compute normalized gas use for ratemaking purposes.

In Formal Case No. 1137 and previously in Formal Case No. 1093, the Commission supported the Company's use of its "*best judgment*" to refine and improve the analyses the Company uses to determining normal weather.[7] Yet, WG's exercise of that discretion became problematic, and in Order No. 21939 the Commission rejected WG's attempted use of an ARCH/GARCH methodology for

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[4] The term "***throughput***" is purposefully employed here in place of WG's use of "***sales***." Since the unbundling of Washington Gas rates in the District of Columbia, WG's primary role is that of **delivering gas** to customers who may elect either to buy gas through the Company and pay PGC charges or contract for gas supplies from a third party vendor of competitive gas supply services. After more than two decades of providing unbundled gas services, it is time for the Company to revise its terminology and use the terms "***throughput***" or "***delivery volumes***" to refer to its overall gas service volumes. The term "*Sales*" should be reserved to address volumes that customers elect to purchase directly from Washington Gas. The volumes witness Raab represents as "*Therm Sales*" in his Weather Normalization analyses, Exhibit WG (N)-4, include substantial volumes that are more appropriately referenced as "***delivery volumes***." "*Throughput*" is a more generic term that can be used appropriately to address both "*sales*" and "*deliveries of gas provided by Competitive Service Providers*."

[5] Formal Case No. 1169, Order No. 21939, page 53, paragraph 169.

[6] Formal Case No. 1137, Order No. 18712, issued March 3, 2017, page 67, paragraphs 184 and 186.

[7] Ibid.

that purpose.[8] That experience must be kept in mind as the Commission considers the details of other changes in data, methods, and assumptions WG employs to estimate normalized gas use by rate class in this proceeding.

It should be noted that, when the Commission accepted the Company's use of a "*simple regression*" methodology in Formal Case No. 1137,[9] the Commission also concluded that "… *use of the regression methodology for the Base Gas factor … should provide a more consistent calculation of Base Gas from rate case to rate case*."[10] Yet, as I will demonstrate below, the results of the Company's regression analyses in this proceeding, particularly for its C&I Heating/Cooling classes in the District of Columbia, are not consistent with that Commission expectation.

Q. DO YOU HAVE ANY FURTHER OBSERVATIONS REGARDING WG'S FILED "NORMAL WEATHER STUDY" IN THIS PROCEEDING?

A. I do. In response to the Commission's determinations in Order No. 21939, in Formal Case No. 1169, WG has used a more appropriate measure of normal heating degree days ("HDDs") in its weather normalization analyses in this proceeding (i.e., 30-year average HDDs) as opposed to HDDs estimated using witness Raab's ARCH/GARCH methodology. However, the data inputs, regression models (which vary by rate class), and analytic assumptions that witness

[8] Formal Case No. 1169, Order No. 21939, paragraph 175, pages 54-55.
[9] Formal Case No. 1137, Order No. 18712, issued March 3, 2017, page 67, paragraph 186.
[10] Ibid.

Raab employs do not yield reasonable or reliable results for all rate classes and do not form a reliable and appropriate basis for the Company's requested ratemaking determinations.

Also, I ask the Commission not to be misled by the title of Washington Gas' "Normal Weather Study." Though Washington Gas uses the title "Normal Weather Study" for its estimation of test year therm use by rate class under normalized conditions, that study includes **significant** normalization adjustments to **non-weather-sensitive** gas use for several classes. In that context, it must be understood that the normalizations included in the Company's study have broader impacts than simple adjustments for fluctuations in weather. For this reason, WG's "Normal Weather Study" should more appropriately be characterized as a "Gas Use Normalization Study" in which adjustments to non-weather-sensitive gas use may be as large, or larger than, weather-related adjustments gas use.

Q. HOW HAVE WASHINGTON GAS'S ESTIMATES OF GAS USE BY RATE CLASS CHANGED OVER RECENT CASES?

A. In this proceeding witness Raab's Exhibit WG (N)-4 estimates total Weather Normalized Therm Use for WG's District of Columbia customers for the twelve months ending March 2024 of **284,130,282 therms**. In Formal Case No. 1169 the Company's comparable estimate for the twelve months ending December 2021 was **275,705,716 therms**.[11] Thus, Washington Gas' estimated normal weather therm use in this proceeding reflects an overall **increase** of about **8.4 million annual therms**.

To further appreciate the components of that **8.4 million** increase in WG's estimate of **annual normal weather gas use**, the Commission is asked to recognize that the Company's Interruptible Service class in the District of Columbia continues to decline. Thus, WG's estimated **8.4 million** increase in annual normal weather gas use comprises a **2.86 million annual therm use decline** for **Non-Firm** customers and an increase of **11.3 million** annual therms for its Firm Service classes in the District. However, WG's estimates of **increases** in Normal Weather Gas use for C&I and GMA heating classes total nearly **12.7 million annual therms** or **13.8%,** while normalized gas use by Residential gas users in the District is estimated to have **declined 1.2%**.[12]

Of the observed increases in WG's estimate of total **Annual Normal Weather** therms, 3.2 million therms reflect increases in estimated Weather Gas requirements while the remaining 5.2 million therms of the overall 8.4 million therm increase (i.e., 61.5% of the total increase) represent **estimated increases in Base Gas Use**. Moreover, when the overall increase in Base Gas use is examined by rate class, WG's estimates for this proceeding yield dramatic increases in estimated Base Gas Use for two rate classes (i.e., the **C&I Heating/Cooling <**

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[11] Case No. 1169, Exhibit WG (N)-5, Page 1 of 28, Schedule 1A.
[12] See Exhibit AOBA (B)-1.

3,075 therm class and the **C&I Heating/Cooling > 3,075** therm class). In fact, the Company's estimates of **increased Base Gas Use** for those two classes account for nearly **7.2 million therms** or **85%** of WG's estimated overall increase in total Normal Weather Gas Use.[13]

Exhibit AOBA (B)-2 demonstrates that, in percentage terms, WG's estimate of Base Gas Use for Small (< 3,075 therm) C&I Heating/Cooling customers is **178.9%** greater than the Company's estimate of Base Gas Use for the same class in Formal Case No. 1169. The Company's estimated increase in Base Gas Use for the Large (> 3,075 therm) C&I Heating/Cooling customers is **27%** greater than WG's estimated Base Gas Use for the same class in Formal Case No. 1169. These large changes in WG's estimates of Base Gas Use are **not** the result of weather fluctuations, and have **no impact** on the Company's assessment of the effects of **weather** gas use or the Company's revenue requirement.

Additionally, WG's assessment of its Peak Day Demands are also influenced by large increases in the **Base Gas** component of the Company's estimated Peak Day requirements. For example, WG's overall estimate of the **Base Gas Use component** of its total Peak Day requirements for the C&I Heating/Cooling < 3,075 class **nearly doubled** between this case and its estimate in Formal Case No. 1169, despite a **5.5% decline** in the Company's estimated total Peak Day demand for that class and only a 4.1% increase in the number of

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13 See AOBA Exhibit (B)-2.

C&I Heating/Cooling < 3,075 customers served. This **doubling** of the **Base Gas** component the C&I Heating/Cooling < 3,075 class Peak Day requirements appears totally inexplicable. Base Gas requirements are generally understood to be relatively stable. Thus, the suggested doubling of a Company's estimate of a class's Base Gas component of its Peak Day requirements should be viewed critically.

When such large changes in usage patterns are observed, there are generally readily observable changes in numbers of customers served, technology, or other factors that explain such changes. However, Washington Gas offers no meaningful observations or explanations to support such large changes in Base Gas Use. Rather, it appears these significant changes in Base Gas Use for WG's C&I Heating/Cooling classes is primarily a product of the modeling methods Washington Gas employs for the affected classes.

Q. AT PAGE 9, LINES 7-10, OF WITNESS RAAB'S DIRECT TESTIMONY HE INDICATES "THE COMPANY USES A SIMPLE LINEAR REGRESSION CALCULATION…"[14] TO ESTIMATE VARIATIONS IN USE PER HEATING DEGREE DAY AND BASE GAS FACTORS. DOES THAT REASONABLY DEPICT THE METHODS WG ACTUALLY EMPLOYS TO ESTIMATE TOTAL NORMAL WEATHER GAS USE BY RATE CLASS?

[14] Exhibit WG (N), the Direct testimony of witness Raab, page 9, lines 7-10.

A. No. Witness Raab's reference to "*a simple linear regression calculation*" is substantially misleading. Simple linear regression equations take the following form:

$y = a + (b * x)$

where:

"y" represents a dependent variable (in this instance gas use per customer);

"a" is a constant (which is relied upon to depict non-weather-sensitive or Base Gas use);

"b" is the estimated co-efficient of the independent or explanatory variable "x";

"x" represents the independent variable (e.g., heating degree days).

The regress model that witness Raab employs for the Company's Commercial and Industrial ("C&I") Non-Heating class take the following form:

$y = a + (b * x_1) + (c * x_2) + (d * x_3) + (e * x_4) + (f * x_5)$

where:

"y" represents a dependent variable (in this instance gas use per customer);

"a" is a constant (which is relied upon to depict non-weather-sensitive or Base Gas use);

"b" is the estimated change in use as associated with a one unit change the number of HDDs for a month;

"x_1" represents monthly heating degree days ("HDDs");

"c" is an estimate of change in Use per Customer associated with a change in the "Trend" variable;

"x_2" represents the ordinal number assigned to a month within the period analyzed;

"d" is an estimate of the monthly impact on gas Use per Customer a class for which gas use is assumed to be impacted by COVID restrictions;

"x_3" a binomial (dummy) variable[15] that is used to identify months in which COVID restrictions were assumed to impact gas Use per Customer;

"e" is an estimate of the monthly impact on gas Use per Customer for a rate class that is the product of an auto regression relationship between variables included in a regression model;

"x_4" represents estimated impact of the Company's auto-regressive variable (AR1) on gas monthly Use per Customer for a rate class;

"e" is an estimate of the impact of witness Raab's use of a SIGMASQ (Sigma Squared) variable on month gas Use per Customer for a rate class;

"x_5" represents witness Raab's SIGMASQ variable the values for which are computed within the regression model for a rate class.

Thus, for the majority of rate classes Washington Gas does **not** use a "*simple linear regression model*." Witness Raab only uses "***simple linear regression***" models for 4 of the Company's 13 rate classes for which estimates of

[15] This "Dummy Variable" assigns a value of "1" (one) to each month assumed to be affected by COVID and a value of "0" (zero) to each month outside the period impacted by COVID restrictions. The simple binomial (on/off) nature of this variable implicitly assumes that COVID had a uniform impact on gas Use per Customer in all months designated as being within the period of COVID restrictions.

Normal Weather Gas Use are developed for this proceeding. Those classes are: (1) Residential Non-Heating – IMA; (2) Residential Non-Heating – Other; (3) Interruptible Service; and (4) Special Contract 2 service. For WG's **nine** other classes of service in the District of Columbia, the Company employs a variety of **multi-variable** regression models that are **not properly characterized** as "*simple linear regression model*." For each of those nine classes, WG includes two or more explanatory variables. Exhibit AOBA (B)-1 identifies the variables used in WG's regression analyses for each rate class, including two or more purportedly explanatory variables.

Witness Raab's reference to his use of "*a simple linear regression calculation*" is deceptive. Although his final calculation of normalized gas use for a rate class is presented in a form that simulates the components of a simple linear regression, the **Base Gas Use component** of that final calculation is **NOT** the estimated value of the "**constant**" from a *simple linear regression* model. Rather, for nine of thirteen rate classes, witness Raab effectively assumes that any factor other than HDDs that influences gas use per customer only impacts Base Gas Use. However, in the context of the significant changes in Base Gas use for C&I Heating/Cooling classes highlighted above, the validity of witness Raab's methods and assumptions must be questioned. They simply do not meet a "***common sense***" test in the absence of greater empirical data to support those results. Clearly, further investigation of the Company's estimates of significant changes in

Base Gas Use for C&I Heating/Cooling classes in the District warrant further investigation. Neither Washington Gas nor witness Raab identifies any change or changes in technology, laws or regulations, or the composition of the rate class that would account for such **large changes in non-weather-sensitive gas use**. Thus, in the absence of greater empirical support for the Company's estimated changes in Base Gas Use, the credibility and equity of the results of the Company's Normal Weather Study must be questioned.

Q. IN FORMAL CASE NO. 1169 YOU DOCUMENTED PROBLEMS IN THE INPUT DATA THAT WERE USED IN WG WEATHER NORMALIZATION REGRESSION MODELS. HAS THE COMPANY ADDRESSED THOSE CONCERNS?

A. Only in part. While it appears that the Company has made some adjustments to its historic data for numbers of Months Billed and Actual Therm Use by rate class, Washington Gas offers only limited explanation of adjustments made to the Company's historic billing data and the reasons for such adjustments. The Company also provides no workpapers to support the adjustments it has made to its historic billing data by rate class. As a result, it is not possible to verify the appropriateness of the adjustments to historic billing data that the Company uses in this proceeding.

Q. WITNESS RAAB'S DIRECT TESTIMONY AT PAGE 11, EXPLAINS THE COMPANY'S DETERMINATION OF "MONTHS BILLED" BY RATE CLASS. DO YOU ACCEPT THAT EXPLANATION AS REASONBLE?

A. No. Witness Raab's Direct testimony explains that data for "Months Billed" found in Schedule 3 of Exhibit WG (N)-4 is a "*calculated field*" which represents "*a normal bill based on the typical number of days served*" in a month.[16] He further explains that if 60 days served were billed on one bill, the calculation would count that as **two** Months Billed. Witness Raab submits that the referenced calculation yields "*an accurate usage per customer calculation*."[17] I do not agree.

Q. WHAT IS THE BASIS FOR YOUR DISAGREEMENT WITH WITNESS RAAB'S REPRESENTATION?

A. The calculation witness Raab describes only addresses part of the problem. Appropriate input data for his regression analyses requires that reported usage be properly associated with the degree day measures for the month in which the usage actually occurred. Simply taking one bill for 60 days of usage and counting that as two Months Billed in the same month does not accomplish that objective.

Q. WHY IS THE COMPANY'S RECOGNITION OF TWO BILLING MONTHS FOR A SIXTY DAY BILLING PERIOD NOT ADEQUATE?

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[16] Exhibit WG (N), page 11, lines 6-7.
[17] Ibid. page 11, lines 9-10.

A. Heating degree days can vary significantly between adjacent billing months. For example, for the month of November 2023 Washington Gas reports **223 HDDs** while the Company shows **536 HDDs** for the month of December 2023. In other words, the actual HDDs for December 2023 were 2.4 times greater than the HDDs for November 2023. In that context, we would expect November gas use per bill to be significantly lower than December gas use per bill. Dividing a 60-day bill rendered in late December 2023 into two billing months recognizes that the bill contains more than one month of gas use, but that step alone neither: (i) recognizes the lower HDDs associated with the usage which occurred in November 2023; nor (ii) the portion of the gas use reported on the December billing that is appropriately attributed to November 2023.

If the two months of usage included in a single bill covering a 60-day billing period are both included in the data for the month in which the bill was rendered, the average use per bill for the billing month is distorted. In the example discussed above, actual use per customer for December 2023 would be understated and that would serve to bias the overall assessment of usage per HDD. Such data problems undermine the credibility of witness Raab's regression model results. A **good** statistical "fit" to **bad data**, cannot be relied upon to produce accurate results. For the Commission and the parties to have confidence in Washington Gas's regression model results the Company must be able to demonstrate that usage for all multi-month billings and all billing adjustments are associated with the heating degree days for the month in which the usage actually occurred.

B. WG'S COST OF SERVICE ALLOCATIONS

Q. HAVE YOU REVIEWED THE DETAIL OF THE JURISDICTIONAL AND CLASS COST OF SERVICE ALLOCATIONS WG WITNESS SMITH PRESENTS IN THIS PROCEEDING?

A. I have. I have reviewed the details of the jurisdictional and class cost of service exhibits that witness Smith presents, as well as the testimony witness Smith offers in support of those exhibits.

Q. DO YOU FIND REASON TO QUESTION THE ACCURACY AND APPROPRIATENESS OF THE COMPANY'S JURISDICTIONAL AND CLASS COST OF SERVICE STUDIES?

A. I do. I have previously discussed concerns relating to the Company's development of its Normal Weather Study estimates of **Normal Annual Therm Use** and **Peak Day Demands**. Those estimates flow directly from witness Raab's analyses directly into the Company's jurisdictional and class cost of service allocation studies. Thus, the flaws in witness Raab's estimation of normalized annual throughput volumes and Peak Day demands distort the development of key allocation factors for Annual Throughput, Peak Day Demands, Composite Peak and Annual Throughput allocations, and a number of other allocations that are influenced by those inputs. This is particularly problematic for the C&I Heating/Cooling < 3,075 therm class for which WG computes a ROR of 4.27%. But for, the significant increase in Base Gas Use (for both Annual Therms and Peak Day requirements) that witness Raab estimates for that class, the C&I Heating/Cooling < 3,075 therm class could have an ROR at or above the system average ROR, and that would noticeably change the revenue increase percentage that WG witness Lawson applies to the class.

Q. ARE THERE OTHER REASONS THE COMMISSION SHOULD QUESTION THE RELIABILITY OF WG'S JURISDICTIONAL ALLOCATIONS OF COSTS?

A. Yes. For example, Witness Smith testifies that the Company's costs for storage are allocated among jurisdictions on the basis of total throughput. However, storage is a seasonal requirement that is driven by usage requirements in Peak Months, not total annual throughput. The Company's use of total throughput to allocate storage costs places inappropriate costs on usage in non-winter months. Furthermore, WG's use of total throughput to allocate seasonal costs, such as those for Storage, distorts the Company's allocations of costs for items allocated on the basis of composite allocation factors, as exemplified by WG's allocations of costs for Common Plant.

I also note that neither witness Smith CCOSS, Exhibit WG (F)-4, nor witness Lawson's Exhibit WG (O)-1, Schedule B, shows the test year Interruptible Gas use attributable to each of the rate blocks of the Company's Interruptible Gas Service rate Schedule. Although the Company's rates include separate Distribution Charges for two gas use categories, the distribution of test year therm use between those two separately priced categories is not documented. The electronic workpapers provided for witness Smith's Exhibit WG (F)-4 only track to a **hard entry** of **$16,025,194** for total Non-Firm (i.e., Interruptible) Service Revenue. Witness Lawson's Exhibit WG (O)-1, Schedule B, only reflects $200,709 of proposed Customer Charge revenue for the Company's Interruptible (Non-Firm) Service class. No Distribution charge revenue for the Interruptible class is presented in that schedule.

Q. IN ORDER NO. 21939 IN FORMAL CASE NO. 1169, THE COMMISSION DIRECTED WG TO FILE A CLASS COST OF SERVICE STUDY THAT CLASSIFIES THE COMPANY'S CNG CUSTOMERS AND REMAINING C&I CUSTOMERS IN SEPARTE RATE CLASSES.[18] HAS WASHINGTON GAS COMPLIED WITH THE COMMISSION'S DIRECTIVE ON THIS MATTER?

[18] Formal Case No. 1169, Order No. 21393, page 119, paragraph 408.

A. Yes. WG's filed CCOSS in this proceeding[19] shows CNG customers as a separate rate class which the Company labels as C&I Non H/C – NGV.[20]. As a result, we now find that with the separation of NGV service from other C&I Non-Heating customers, the Company's computed rate of return for NGV service is now found to be negative, while the rate of return for customers remaining in the Company's C&I Non-H/C class jumps from **6.23%** (as computed by WG in Formal Case No. 1169) to **10.58%**. The rate of return for the C&I Non-H/C class is now the highest for any class of District ratepayers and equates to more than **2.2 times** the Company's overall rate of return for its District of Columbia service territory.

Q. ARE THERE ANY ADDITIONAL COST OF SERVICE ALLOCATION ISSUES THAT YOU WOULD LIKE TO ADDRESS AT THIS TIME?

A. Yes, Washington Gas greatly under-utilizes the potential of its cost allocations studies in the development of its proposed rates. The only observable link between WG's CCOSS and its rate structure proposals is found in the Company's distribution of its revenue increase request among rate classes, as I discuss in greater detail below. However, even that linkage is based on little more than loose association of proposed increase percentages with above or below system average rates of return for individual rate classes. For example, the C&I Non-Heating class, for which WG's CCOSS shows a rate of return that equates to more

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[19] Exhibit WG (F)-4.
[20] In this testimony I refer to the C&I Non H/C – NGV class, simply as "NGV" service.

than 2.2 times the jurisdictional average rate of return (i.e. a UROR of 2.22), receives the same percentage rate increase as the C&I Heating/Cooling > 3,075 therm class which has a computed rate of return that equated to only about 1.2 times the system average rate of return.

Furthermore, although allusions are made to the Company's use of cost-based ratemaking considerations, Washington Gas offers no calculations of unit costs to which the levels of the Company's proposed Monthly Customer Charges, Distribution Charges, and Peak Usage Charges can be compared. In that context, Washington Gas's proposal to increase its customer charges **for all rate classes** by 25% is not supported by any assessments of the Company's actual monthly costs per customer by rate class. Instead, the increases in Customer Charges that Washington Gas proposes appear to be primarily the product of the Company's desire to collect more of its costs through fixed charges without regard for cost causation patterns by rate class. This request for greater recovery of revenue through fixed charges is not unexpected from a utility monopoly. Any claim that Washington Gas's rates in the District of Columbia are reflective of cost-based ratemaking must be reserved for the overall revenue requirement that the Commission ultimately approves. No basis exists for claims that WG's rate and charges of individual rate classes are cost-based. It is understood that the Commission can exercise considerable discretion to account for non-cost-based factors in the setting of rates. However, as the frequency and size of departures from cost-based rates increase, the Commission's ability to differentiate cost-based and non-cost-based rate proposals diminishes.

Q. DOES WITNESS SMITH, OR ANY OTHER WITNESS FOR WG, DISCUSS THE IMPACTS OF THE COMPANY'S COMPUTED SIGNIFICANTLY BELOW SYSTEM AVERAGE RATE OF RETURN FOR SPECIAL CONTRACTS ON THE REVENUES WG SEEKS TO RECOVER FROM ITS OTHER CUSTOMERS IN THE DISTRICT?

A. No. Washington Gas negotiated Special Contracts with GSA and the Architect of the Capital ("AOC") that the Company represented, at the time those contracts were approved by the Commission, would fully recover their costs of service. However, the Company's Class Cost of Service Study in this proceeding shows, once again, that those contracts are under-performing and providing substantially less than its jurisdictional average rate of return, as well as much less than the 7.87% overall rate of return for which WG seeks approval in this proceeding. Given that the Commission apparently cannot increase charges under the Company's negotiated Special Contracts, I submit that Washington Gas, and not its other ratepayers in the District, should bear responsibility for agreements that have failed to meet the Company's rate of return requirements. The impact of this issue on Washington Gas's requested revenue is addressed in the Direct Testimony of AOBA witness Timothy Oliver.

C. WG'S RATE STRUCTURE PROPOSALS

Q. WHAT ELEMENTS OF WG'S RATE STRUCTURE PROPOSALS DO YOU ADDRESS?

A. This section addresses four elements of the Rate Structure proposals presented by Washington Gas witness Lawson. Those elements include:

- The Company's proposed distribution of its requested revenue increase among rate classes;
- WG's proposed charges for C&I and GMA Heating/ Cooling and C&I and GMA Non-Heating customers;
- WG's proposed Charges for Interruptible Service; and
- WG proposed WNA mechanism.
- WG's proposed Miscellaneous Service Charges

1. WG's Proposed Revenue Increase Distribution

Q. HOW DOES WASHINGTON GAS PROPOSE TO DISTRIBUTE ITS REQUESTED REVENUE INCREASE AMONG RATE CLASSES?

A. As explained by WG witness Lawson, the Company proposes to differentiate the revenue increase percentages it seeks based on the relative rates of return by rate class computed in the Company's Class Cost of Service Study ("CCOSS"). For classes well below the system average rate of return (i.e., CNP service and NGVs), Washington Gas proposes revenue increases that reflect 1.25 times the system average increase. Given that the Company's overall increase request represents a **30.29%** increase, WG's proposals would impose a 37.86% increase on those classes. For classes with computed rates of return relatively near, but below, the system average rate of return, the Company proposes revenue increases that equate to 1.10 times the overall average increase. Classes assessed by the Company to be earning rates of return in excess of the system average rate of return receive proportionate shares of the remainder of Washington Gas's requested revenue increase or 26.31% increases.

Q. DO YOU FIND THE COMPANY'S PROPOSED DISTRIBUTION OF ITS REQUESTED REVENUE INCREASE REASONABLE?

A. Considering the overall magnitude of the revenue increase that Washington Gas seeks in this proceeding (which is far in excess of an inflation-based increase), restraint in the differentiation of revenue increase percentages among rate classes is generally considered appropriate. WG's proposal exercises such restraint. However, the Commission should be troubled by the negative rates of return that Washington Gas computes for Combined Heat and Power ("CHP") service and Natural Gas Vehicle {"NGV"). Washington Gas offers no support for the continued subsidization by other classes of service for these somewhat unique and limited service offerings. The Company has failed to provide evidence that its CHP offering is attracting additional participants and that continued subsidization of that rate which serves only one customer is necessary or appropriate. Likewise, given substantial expansion of the numbers of Electric Vehicle charging facilities in the District, the likelihood of greater use of natural gas fueled vehicles in the District of Columbia appears low.

Given the foregoing observations, this Commission should investigate whether continued offering of these services at subsidized rates provides any net benefits to the District and/or other Washington Gas customers in the District. If not, the Commission should require WG to begin a phase-out of those services.

2. Charges for C&I and GMA Heating/Cooling and Non-Heating Customers[21]

Q. WHAT CHARGES DOES WG WITNESS LAWSON PROPOSE FOR ITS C&I AND GMA HEATING/COOLING AND NON-HEATING CUSTOMERS?

A. The Customer, Distribution, and Peak Usage charges that WG witness Lawson proposes for Heating/Cooling customers and for Non-Heating customers within its C&I and GMA rate classes are presented on pages 7 and 8 of witness Lawson's

[21] This discussion specifically does not address rates for Natural Gas Vehicles ("NGVs") and Combined Heat and Power ("CHP") customers, which are classified by the Company as C&I class in the Company's CCOSS but have much different costs and much different existing rate structures.

Direct testimony, as well as in his Exhibits WG (O)-1, Schedule B, and Exhibit WG (O)-4. Those proposed charges and the effective increases they represent are summarized in **Table 1**, below, and in Exhibit AOBA (B)-3.

Table 1

WG's Proposed Changes in Charges for Gas Service
For C&I and GMA Heating/Cooling and Non-Heating Customers

	Present	Proposed	Increase	% Incr
Customer Charges				
C&I H/C < 3075	$ 29.90	$ 37.40	$ 7.50	25.08%
C&I H/C >3,075	$ 70.05	$ 87.55	$ 17.50	24.98%
C&I Non-Heating	$ 28.50	$ 35.65	$ 7.15	25.09%
GMA H/C < 3075	$ 28.50	$ 35.65	$ 7.15	25.09%
GMA H/C >3,075	$ 70.50	$ 87.60	$ 17.10	24.26%
GMA Non-Heating	$ 28.50	$ 35.65	$ 7.15	25.09%
Distribution Charges				
C&I H/C < 3075	$ 0.5821	$ 0.8010	$ 0.2198	**37.61%**
C&I H/C >3,075	$ 0.4796	$ 0.6063	$ 0.1267	26.42%
C&I Non-Heating	$ 0.4811	$ 0.6087	$ 0.1276	26.52%
GMA H/C < 3075	$ 0.4930	$ 0.6252	$ 0.1322	26.82%
GMA H/C >3,075	$ 0.4863	$ 0.6148	$ 0.1285	26.42%
GMA Non-Heating	$ 0.4841	$ 0.6124	$ 0.1283	26.50%
Peak Usage Charges				
C&I H/C < 3075	$ 0.0519	$ 0.0692	$ 0.0173	**33.33%**
C&I H/C >3,075	$ 0.0421	$ 0.0532	$ 0.0111	26.37%
C&I Non-Heating	$ 0.0423	$ 0.0534	$ 0.0111	26.24%
GMA H/C < 3075	$ 0.0431	$ 0.0544	$ 0.0113	26.22%
GMA H/C >3,075	$ 0.0422	$ 0.0533	$ 0.0111	26.30%
GMA Non-Heating	$ 0.0423	$ 0.0534	$ 0.0111	26.24%

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S PROPOSED CHARGES FOR C&I AND GMA HEATING/COOLING AND NON-HEATING CUSTOMERS?

A. The proposed Distribution Charges and Peak Usage Charges for all categories of C&I and GMA service, except C&I Heating/Cooling < 3,075 therms, exhibit only minor variations. Likewise, the proposed Customer Charges for all categories of C&I and GMA Heating and Non-Heating service are essentially uniform, except that Heating/Cooling customers using greater than 3,075 therms have a higher monthly customer charge. The greatest distinction in the Company's proposed charges is a product of the larger overall percentage increase that Washington Gas proposes for C&I Heating/Cooling customers using < 3,075 therms. However, as I have previously discussed, the Company's proposed larger percentage increase for the C&I Heating/Cooling customers using < 3,075 therms is a product of the Company's significant change in its estimate of Base Gas Use for those customers.

Given my concerns regarding large variations in WG's assessments of Base Gas Use from case-to-case for its C&I Heating/Cooling rate classes, the Commission should be cautious regarding applying too much weight to class cost allocation results that are biased by fluctuating assessments of non-weather-sensitive gas service requirements. For this reason, I believe it would be more appropriate in this proceeding for all C&I and GMA services to be priced in a more uniform manner. Although I would maintain higher monthly Customer Charges for

Heating/Cooling customers with use in excess of 3,075 therms, I would establish a single set of Distribution Charges and Peak Usage Charges for all C&I and GMA Heating/Cooling and Non-Heating service. This would simplify the Company's rates and make the Company's charges more understandable for customers. Moreover, this change in the Company's proposals can be easily implemented with no impact on other rate classes (e.g., Residential service) and minimal impacts on individual C&I GMA Heating/Cooling and Non-Heating rate classifications.

Q. WHAT ARE THE CHARGES YOU PROPOSE FOR C&I AND GMA HEATING/ COOLING AND NON-HEATING CUSTOMERS?

A. I propose are set forth as AOBA's proposed charges in **Table 2**, below.

Table 2

WG's Proposed Changes in Charges for Gas Service
For C&I and GMA Heating/Cooling and Non-Heating Customers

	Proposed Charges			
	Wash Gas	**AOBA**	**Difference**	**% Diff**
Customer Charges				
C&I H/C < 3075	$ 37.40	$ 37.50	$ 0.10	0.3%
C&I H/C >3,075	$ 87.55	$ 86.00	$ (1.55)	-1.8%
C&I Non-Htg	$ 35.65	$ 37.50	$ 1.85	5.2%
GMA H/C < 3075	$ 35.65	$ 37.50	$ 1.85	5.2%
GMA H/C >3,075	$ 87.60	$ 86.00	$ (1.60)	-1.8%
GMA Non-Htg	$ 35.65	$ 37.50	$ 1.85	5.2%
Distribution Charges				
C&I H/C >3,075	0.6063	0.6180	$ 0.0117	1.9%
C&I Non-Htg	0.6087	0.6180	$ 0.0093	1.5%
GMA H/C < 3075	0.6252	0.6180	$ (0.0072)	-1.2%
GMA H/C >3,075	0.6148	0.6180	$ 0.0032	0.5%
GMA Non-Htg	0.6124	0.6180	$ 0.0056	0.9%
Peak Usage Charges				
C&I H/C < 3075	$ 0.0692	$ 0.0540	$ (0.0152)	-21.9%
C&I H/C >3,075	$ 0.0532	$ 0.0540	$ 0.0008	1.5%
C&I Non-Htg	$ 0.0534	$ 0.0540	$ 0.0006	1.2%
GMA H/C < 3075	$ 0.0544	$ 0.0540	$ (0.0004)	-0.7%
GMA H/C >3,075	$ 0.0533	$ 0.0540	$ 0.0007	1.4%
GMA Non-Htg	$ 0.0534	$ 0.0540	$ 0.0006	1.2%

Table 3 demonstrates the revenue neutrality of AOBA's rate design proposal for the listed C&I and GMA rate classes.

Table 3

AOBA's Proposed Charges for Gas Service
For C&I and GMA Heating/Cooling and Non-Heating Customers

	Proposed Revenue			
	Wash Gas	**AOBA**	**Difference**	**% Diff**
Customer Chrg Revenue				
C&I H/C < 3075	$ 2,018,927	$ 2,024,325	$ 5,398	0.3%
C&I H/C >3,075	$ 3,561,445	$ 3,498,394	$ (63,051)	-1.8%
C&I Non-Htg	$ 789,113	$ 830,063	$ 40,950	5.2%
GMA H/C < 3075	$ 255,860	$ 269,138	$ 13,278	5.2%
GMA H/C >3,075	$ 1,794,486	$ 1,761,710	$ (32,776)	-1.8%
GMA Non-Htg	$ 371,830	$ 391,125	$ 19,295	5.2%
Total Customer Revenue	$ 8,791,661	$ 8,774,754	$ (16,907)	-0.2%
Distribution Chrg Revenue				
C&I H/C < 3075	$ 4,274,246	$ 3,297,733	$ (976,513)	-22.8%
C&I H/C >3,075	$ 41,746,425	$ 42,552,022	$ 805,597	1.9%
C&I Non-Htg	$ 4,877,350	$ 4,951,868	$ 74,518	1.5%
GMA H/C < 3075	$ 624,686	$ 617,493	$ (7,193)	-1.2%
GMA H/C >3,075	$ 18,243,638	$ 18,338,596	$ 94,958	0.5%
GMA Non-Htg	$ 2,406,639	$ 2,428,646	$ 22,007	0.9%
Total Dist Chg Revenue	$ 72,172,984	$ 72,186,358	$ 13,374	0.0%
Peak Usage Revenue				
C&I H/C < 3075	$ 326,158	$ 254,631	$ (71,527)	-21.9%
C&I H/C >3,075	$ 3,042,967	$ 3,090,132	$ 47,165	1.5%
C&I Non-Htg	$ 373,778	$ 378,118	$ 4,340	1.2%
GMA H/C < 3075	$ 37,543	$ 37,284	$ (259)	-0.7%
GMA H/C >3,075	$ 1,346,175	$ 1,364,467	$ 18,292	1.4%
GMA Non-Htg	$ 170,197	$ 172,186	$ 1,989	1.2%
Total Peak Use Revenue	$ 5,296,818	$ 5,296,818	$ 0	0.0%
Total Revenue All Chgs	$ 86,261,463	$ 86,257,930	$ (3,533)	0.0%

Q. HOW SHOULD AOBA'S PROPOSED CHARGES FOR THE REFERENCED C&I AND GMA RATE CLASSIFICATIONS BE ADJUSTED IF LESS THAN THE COMPANY'S FULL REVENUE INCREASE REQUEST IS APPROVED?

A. In the event the Commission approves less than WG's full revenue increase request, I would recommend that AOBA's proposed charges be scaled downward in a proportionate manner.

3. Interruptible Service Charges

Q. DO YOU OFFER ANY GENERAL OBSERVATIONS REGARDING WG'S DEVELOPMENT OF ITS PROPOSED RATES FOR INTERRUPTIBLE SERVICE CUSTOMERS?

A. Yes. I have previously reviewed pricing proposal for Interruptible Service offerings for a number of utilities in various jurisdictions, and I find WG's development and presentation of its rates for Interruptible Service among the most obtuse presentations I have encountered.

Q. WHY IS THE COMPANY'S PRICING OF INTERRUPTIBLE SERVICE IMPORTANT TO AOBA?

A. Although WG's Interruptible Service rate classification has been shrinking over time in terms of both numbers of customers served and therms of gas delivered annually, AOBA still represents a number of users of Interruptible Gas Service in the District. Moreover, the Company's proposed pricing of Interruptible Service will have a significant impact on customers' decisions regarding continued utilization of that service.

In Formal Case No. 1169, WG's witnesses made a number of inappropriate and unsupported assessments about the Company's costs of providing Interruptible Gas Service, and failed to properly consider the added costs that WG's Interruptible gas service customers must incur on an annual basis to participate in the Company's Interruptible Service offerings,[22] even if no actual interruptions are encountered in a given winter period. AOBA continues to believe that Interruptible Gas Service provides valuable gas supply flexibility to WG's District of Columbia operations and the value should be reflected in the Company's pricing of its Interruptible Service Offerings.

Q. HOW DOES WG WITNESS LAWSON PROPOSE TO ADJUST THE COMPANY'S CHARGES FOR ITS INTERRUPTIBLE GAS SERVICE IN THE DISTRICT?

A. Witness Lawson proposes to increase the Interruptible Customer Charge by roughly 25%. He also proposed to increase the Distribution Charges for Interruptible Service Customers by over **37.8%** (i.e., among the largest percentage

[22] See Formal Case No. 1169, Exhibit AOBA (A), page 55, lines 7-31.

increases applied to an individual charge for any non-residential rate class). Those proposed increases, if implemented, will once again served to narrow the cost differentials between Interruptible Service and Firm Service alternatives, as well as make non-gas alternatives more economically attractive.

Q. HOW MUCH HAS WG'S INTERRUPTIBLE SERVICE DECLINED IN RECENT YEARS?

A. Over a little more than one decade (i.e., since Formal Case No. 1093), WG's interruptible service volumes have fallen from 104.9 million annual therms to less than 40.0 million annual therms (i.e., a 62% decline). In addition, the number of customers in the District using WG's Interruptible Service has declined from 190 to about 105 (i.e., a 45% decline).

Q. DOES THE FACT THAT INTERRUPTIBLE SERVICE CUSTOMERS MAY REMAIN ON THE SYSTEM WITHOUT SERVICE INTERRUPTION DURING A NORMAL OR WARMER THAN NORMAL WINTER NEGATE THE VALUE THEY PROVIDE TO THE COMPANY AND ITS FIRM SERVICE CUSTOMERS DURING EXTREME WEATHER CONDITIONS?

A. No. The value Interruptible Service customers provide lies primarily in the Company's ability to plan for lesser levels of capacity requirements and reduce planning uncertainties and the operating flexibility that service offers under extreme weather conditions. Those benefits are not dependent on whether there are actual service interruptions in any given year.

Q. DOES WASHINGTON GAS HAVE MECHANISMS IN PLACE TO ENSURE THE COMPANY'S ABILITY TO CURTAIL GAS SERVICE TO NON-FIRM CUSTOMERS ON DEMAND?

A. Yes, each Interruptible Service customer must annually demonstrate its ability to comply with the service interruption requests that may be issued by the Company with limited advance notice. In addition, customers who do not comply with service interruption/curtailment requests are subject to significant rate penalties.

4. WG's Proposed WNA Mechanism

Q. HAVE YOU REVIEWED THE DETAILS OF THE WEATHER NORMALIZATION ADJUSTMENT ("WNA") MECHANISM THAT WASHINGTON GAS PROPOSES IN THIS PROCEEDING?

A. Yes, I have.

Q. WHAT IS THE PURPOSE OF THE WNA MECHANISM THAT WASHINGTON GAS PROPOSES IN THIS PROCEEDING?

A. Washington Gas witness Lawson submits that the proposed WNA mechanism is intended to "*adjust customer bills during the WNA Period* (October – May) *to reduce the impact of weather variability from normal*."[23]

Q. WG WITNESS TUORINIEMI REPRESENTS THAT THE COMPANY'S PROPOSED WNA MECHANISM BENEFITS CUSTOMERS BY "STABILIZING THE NON-GAS PORTION OF CUSTOMERS' RATES. DO YOU AGREE?

A. No. Given that WNA rate adjustments are not applied to the month or months in which usage is impacted by a fluctuation in weather, as measured by Heating Degree Days ("HDDs"), the Company's proposed WNA rate adjustment can actually appear to customers as increased volatility in their monthly billings. The primary beneficiary of WG's proposed WNA mechanism is the Company which gains greater assurance of the revenues it can expect to recover for any given winter period. As a result, the revenue recovery risk that Washington Gas faces would be reduced.

Q. UNDER THE COMPANY'S PROPOSED WNA, WILL THE NON-GAS PORTION OF CUSTOMERS MONTHLY BILLS REMAIN UNCHANGED WHEN ACTUAL NUMBERS OF HEATING DEGREE DAYS VARY FROM NORMAL HEATING DEGREE DAYS FOR A MONTH?

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[23] Exhibit WG (O), page 15, lines 9-11.

A. No. Customer's bills will continue to reflect their actual metered usage for each month, and if a departure from "normal heating degree days" is experienced, customers' bills will continue to reflect the impact of actual HDD variations from normal weather on their gas use requirements. Adjustments for fluctuations from expected normal gas use will be reflected in adjustments to charges applied in subsequent periods.

Q. DOES THE "WNA" MECHANISM THAT WASHINGTON GAS PROPOSES IN THIS PROCEEDING DIFFER FROM THE "CPA" MECHANISM THAT WASHINGTON GAS PROPOSED IN FORMAL CASE NO. 1169?

A. Yes. Several attributes of WG's proposed WNA mechanism differ noticeably from those of the mechanisms the Company has previously proposed. Perhaps most notably, it is a seasonal mechanism which only computes the impacts of Heating degree day variations on Distribution Charge revenue by rate class for the months of October through May. In that context, the focus of the Company's proposal is truly on the impacts of weather. It is not a mechanism that is either implicitly or explicitly intended to function as a revenue decoupling mechanism (i.e., a type of mechanism that AOBA has found more problematic).

Q. WILL THE PROPOSED WNA REFLECT THE IMPACTS OF WEATHER ON PEAK DAY USAGE CHARGE REVENUE?

A. My understanding is that the proposed WNA is only designed to address the effects of variations form normal monthly HDD levels on WG's recovery of Distribution revenue. Although there may be weather-related impacts on customers Peak Usage, Washington Gas's methodology for computing Peak Usage Charges uses measures of peak usage derived from the prior November – April billing periods to assess Peak Usage Charges to applicable rate classes. As a result, variations in actual usage during the current period do not impact the Company's Peak billed Usage Charge revenues.

Q. ARE THERE ELEMENTS OF THE COMPANY'S WNA PROPOSAL WITH WHICH YOU HAVE CONCERNS?

A. Yes. I have at least three concerns regarding the manner in which the Company proposes to implement monthly rate adjustments.

First, I do not support the Company's plan to accrue under-recoveries but pass back to customers any over-recoveries amounts through monthly WNA credits. That aspect of the Company's WNA proposal will tend to amplify the size of subsequent WNA rate adjustments and make the mechanism more difficult for customers to absorb. Accrual of both under-recovery and over-recovery amounts provide the potential that monthly accrued amounts may be at least partially offsetting, thereby moderating the level of subsequent WNA charges or credits.

Second, I believe the Company's proposed +/-15% cap on monthly rate adjustments is too large and could be problematic for customers who may have little forewarning of the magnitude of the adjustments they may face. A cap of not greater than +/-10% of a class's applicable Distribution Charge per therm should be adequate for this mechanism.

Third, the Company's proposals with respect to billing very small WNA factors add unnecessary complexity and discretion to the rate adjustment process. If a rate adjustment calculation yields a very small factor, I find no reason for the Company to adjust the number of months over which the factor would be billed to arbitrarily increase the size of the factor. Rather, I recommend that recovery of any accrued balance that would produce an adjustment factor that equates to less than **+/-1%** should be deferred with interest until either the end of the next WNA period or when the Company's accrued balance exceeds the equivalent of **+/-5%** of a classes applicable Distribution Charge per therm. This alternative approach avoids the parties need to expend resources to compute and track very small WNA rate adjustments.

Q. DOES WASHINGTON GAS REFLECT THE REDUCED REVENUE RECOVERY RISK THAT A WNA WOULD PROVIDE WHEN CONSIDERING WG'S RATE OF RETURN REQUEST IN THIS PROCEEDING?

A. No, it does not. The Direct testimony of WG witness D'Ascendis asserts that WG's "*lack of a weather normalization adjustment is indicative of an increased level of risk for investors as compared to* [his] *Utility Proxy Group*,"[24] but he offers no assessment of the impact of the Company's proposed WNA mechanism on WG's equity return requirements. AOBA witness Timothy Oliver offers further discussion of this matter.

5. Miscellaneous Service Charges

Q. IN FORMAL CASE NO. 1169 WASHINGTON GAS THROUGH THE REBUTTAL TESTIMONY OF WITNESS LAWSON COMMITTED TO UPDATING THE COMPANY'S MISCELLANEOUS SERVICE CHARGES IN ITS NEXT BASE RATE PROCEEDING.[25] HAS THE COMPANY MET THAT COMMITMENT IN ITS FILED DIRECT TESTMONY IN THIS PROCEEDING?

A. Yes, the Direct Testimony of WG witness Lawson in this proceeding proposes updates to certain of the Company's current Miscellaneous Service Charges, many of which have not been updated in more than a decade. However, in each instance that witness Lawson proposed to update an existing charge, the amount of the increase is arbitrarily limited to either a 10% or 20% increase. Interestingly, the limits WG places on increases to its Miscellaneous Service Charges are lower than

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[24] Exhibit WG (C), page 48, lines 19-23.
[25] Formal Case No. 1169, Exhibit WG (2O), page 9, line 21, through page 10, line 2.

the limits the Company places on the rate increases it proposes by rate class and by charge in its development of proposed rates and charges for Distribution Services. In each case those limits appear subjectively determined, and the Company makes no representations to continue to pursue adjustments to those charges in future cases until they more directly reflect WG's costs of providing the subject services.

Witness Lawson testifies, for example, that he weighed the impact of an increase in the Company's Reconnect Charge for customers to be reconnected. However, his testimony lacks any documentation of the data and criteria used to weigh such impacts. Likewise, witness Lawson's proposed percentage limits on other Miscellaneous Service Charges appear to be based on little more than his unsupported judgmental determinations. Finally, I find witness Lawson's argument that the limited increases in the service charges he proposes will have "*no impact on* [the Company's] proposed *rates*" in this proceeding somewhat of a self-fulling prophesy. Naturally, if adjustments to Miscellaneous Service Charges are limited, the impacts they have on other rates and charges cannot be expected to be substantial. Furthermore, that rationale does not negate the merits of more cost based charges. Following witness Lawson's criteria, the Company might as well simply ignore cost-based ratemaking considerations, and provide all of its miscellaneous services at no charge to the customers requiring those services.

IV. CONCLUSION AND RECOMMENDATIONS

A. CONCLUSION

Q. DO YOU OFFER ANY CONCLUDING OBSERVATIONS?

A. The Commission is asked to recognized that the analyses Washington Gas presents as its "Normal Weather Study" actually makes significant changes on the Company's estimates of **Base (non-sensitive) Gas Use**. In that context, the study sponsored by WG witness Raab would be more appropriately labeled as a Gas Use Normalization Study. Still key elements of Washington Gas's "Normal Weather Study" and data and analytic methods used therein continue to be problematic and yield inexplicable changes in Company's estimates of **Base (non-sensitive) Gas Use** that erode the reasonableness and reliability of much of the Company's ratemaking presentations in this proceeding.

An example of the negative influence of WG's estimates of Normalized Therm Use is its impact on the Company's computed rate of return for the Company's C&I Heating/Cooling classes, particularly the C&I Heating/Cooling < 3,075 class. For that class, WG's very large increase in estimated base gas use pushes the class rate of return below the system average and results in the Company proposing a noticeably greater than system average revenue increase for the class.

Except for WG's proposed charges for C&I Heating/Cooling < 3,075 customers, the Company's **proposed** charges for C&I and GMA Heating/Cooling and Non-Heating services are very similar in magnitude. This testimony suggests that in this proceeding the Commission should simplify and unify WG's charges for all C&I and GMA classes of service (excluding WG's CHP and NGV services which have distinctly different usage characteristics). One exception is that the monthly Customer Charge for large C&I and GMA customers is higher than the Customer Charge for smaller heating and cooling and non-heating customers in the C&I and GMA rate classes.

WG's rate proposals for its Interruptible Service customers in the District of Columbia, as well as the underlying costs allocations on which WG bases its proposed revenue increase for that class, place inappropriate and undue cost burdens on customers who utilize that service. The Company's cost allocations and rate structure proposals for its Interruptible Service class continue to ignore the value of the planning benefits and operational flexibility that Interruptible Service customers provide. The Company also continues to overlook the **extra** annual operating costs that Interruptible Service customers must incur to maintain their ability to respond to service curtailment requests and the penalties they face if they fail to comply with such requests. These are costs (and penalties) that Firm Service customers do not face. As a result, further increases in Interruptible Service charges, relative to those for otherwise available Firm Service offerings, will only erode the economics of continued use of WG's Interruptible Service and further shrink the size of WG's Interruptible Service class in the District. That would, in turn, reduce the Company's operating flexibility during extreme weather events.

Interruptible Gas Service continues to provide valuable gas supply flexibility to WG's District of Columbia operations and the planning of the Company's system in the District. That value should be reflected in the Company's pricing of its Interruptible Service Offerings. Customers should not simply be forced from that class through onerous rate increases.

WG's proposed Weather Normalization Adjustment ("WNA") Mechanism is distinctly different from the revenue decoupling mechanisms Washington Gas proffered in several prior proceedings, and with a few refinements, recommended herein, that mechanism could be acceptable to AOBA and the customers AOBA represents with a concurrent reduction in the Company's return on equity.[26]

B. RECOMMENDATIONS

Q. WHAT ACTIONS DO YOU RECOMMEND THAT THE COMMISSION TAKE WITH RESPECT TO THE COMPANY'S PROPOSALS IN THIS PROCEEDING?

[26] See AOBA Exhibit (A), the Direct testimony of Timothy Oliver in this proceeding.

A. Elements of the recommendations that I present in this testimony are summarized below. This summary is not necessarily comprehensive, and thus, omission from this summary of any recommendation that appears elsewhere in this testimony is not intended to suggest that it is of lesser importance or priority.

<u>WG's Estimation of Normal Weather Therm Use</u>

1. The Commission should find that WG's purported Normal Weather Study makes greater changes to the Company's estimates of Base (non-weather-sensitive) Gas Use than it makes to Weather-Sensitive portions of District customers' gas service requirements. As a result, the adjustments the Company makes to non-weather-sensitive gas use deserve as much or greater scrutiny than WG's development of its estimates of weather-related influences on gas use by rate class.

2. The Commission should recognize that WG's estimates of Base Gas Use influence the Company's estimates of Peak Day Demands by rate class, as well as its assessments of Normal Annual Therm Use.

3. The Commission should find that WG's substantial departure from the use of simple linear regression models in the development of its Normal Weather Study greatly complicates the interpretation of regression model

results, and witness Raab's simplifying assumption that all variations in gas use, not directly captured by his Heating Degree Day variable coefficients, unduly bias results of his analyses.

4. The Commission should find that WG's use of a crudely constructed COVID Dummy variable in its weather normalization analyses does not produce meaningful assessments of the impacts of COVID on test year gas use.

<u>WG's Cost of Service Allocations</u>

5. The Commission should find that the data which flows from WG's Normal Weather Study into its cost allocations to support the development of key cost allocations factors impedes the accuracy and reliability of the Company's computed jurisdictional and customer class rates of return.

6. The Commission should be concerned by the negative rates of return that Washington Gas computes for its CHP and NGV services, and in light of those results, the Commission should either: (a) require the rates and charges for those services to be reset in a manner that yields rates of return that reasonably approximate the Company's overall jurisdictional return requirement; or (2) consider phasing-out those rate offerings.

7. The Commission should observe that WG's presentation of separate cost allocation results for its NGV service and for all other C&I Non-Heating customers yields a substantial increase in the rate of return for the C&I Non-Heating class which now has clearly the highest rate of return of any class of WG's District of Columbia rate classes. That large upward jump in the C&I Non-Heating class rate of return warrants special consideration in the determination of class revenue requirements.

8. The Commission should find that WG's other District of Columbia ratepayers are not responsible for revenue short-falls that result from rate of return deficiencies identified for WG's Special Contract services.

<u>Rate Structure Considerations</u>

9. The Commission should move toward greater unification of WG's charges for C&I and GMA Heating/Cooling and Non-Heating charges for gas service.

10. The Commission should assess that WG's proposed WNA mechanism is an improvement over the revenue decoupling mechanisms the Company has proposed in several recent proceedings. With some fine tuning of

details, the mechanism WG proposes, with a downward adjustment to the Company's authorized ROE, could be appropriate for implementation.

11. The Commission should limit increases in rates and charges for Interruptible Service to levels that are not greater in percentage terms than the overall average increases the Company applies to its firm service rates for C&I and GMA Heating/Cooling and Non-Heating customers.

12. The Commission should view WG's proposed increases in its Miscell-aneous Service Charges represent a step in the right direction. However, the judgmental limits on movement toward more cost-based adjustments to such charges are inconsistent with the limits the Company recommends for increases in charges for its Firm Service rate offerings. If the Company's proposed limits on the Miscellaneous Charge increases implemented in this proceeding are accepted, the Commission should require further movement toward more costs-based Miscellaneous Service Charges in the Company's subsequent rate cases.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF	)	
	)	
The Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Gas Service	)))	**Formal Case No. 1180**

DECLARATION

I, Bruce R. Oliver, do hereby declare under the penalty of perjury that I am authorized to make this Declaration on behalf of the Apartment and Office Building Association of Metropolitan Washington; that the foregoing testimony and exhibits were prepared by me or under my direction and supervision; and that the contents herein are true and correct to the best of my knowledge, information and belief.

Bruce R. Oliver

Bruce R. Oliver
January 24, 2025

Washington Gas Light Company
DC PSC Formal Case No. 1180

Analysis of WG Estimates of Normalized Annual Throughput Volumes - FC 1169 vs FC 1180

	FC 1169 - WG Estimates Total Normalized Therms			FC 1180 - WG Estimates Total Normalized Therms			Difference FC 1180 - FC 1169 Total Normalized Therms			Difference FC 1180 - FC 1169 Total Normalized Therms		
	Weather Gas	Base Gas	Total Peak Day	Weather Gas	Base Gas	Total Peak Day	Weather Gas	Base Gas	Total Peak Day	Weather Gas	Base Gas	Total Peak Day
Residential												
H/C	71,990,319	13,858,602	85,848,921	70,729,615	14,063,551	84,793,166	(1,260,704)	204,949	(1,055,755)	-1.8%	1.5%	-1.2%
Non H/C - IMA	334,550	399,479	734,029	309,352	368,268	677,620	(25,198)	(31,211)	(56,409)	-7.5%	-7.8%	-7.7%
Non H/C	1,232,802	435,354	1,668,156	1,287,100	416,434	1,703,534	54,298	(18,920)	35,378	4.4%	-4.3%	2.1%
Total Residential	73,557,671	14,693,435	88,251,106	72,326,067	14,848,253	87,174,320	(1,231,604)	154,818	(1,076,786)	-1.7%	1.1%	-1.2%
Commercial & Industrial												
H/C < 3,075	4,236,603	458,669	4,695,272	4,057,018	1,279,120	5,336,138	(179,585)	820,451	640,866	-4.2%	**178.9%**	13.6%
H/C > 3,075	35,123,041	23,283,899	58,406,940	39,197,035	29,657,369	68,854,404	4,073,994	6,373,470	10,447,464	11.6%	**27.4%**	17.9%
Non H/C	2,752,704	5,101,611	7,854,315	2,745,262	5,267,470	8,012,732	(7,442)	165,859	158,417	-0.3%	3.3%	2.0%
CHP	1,222,684	1,300,402	2,523,086	1,127,791	973,241	2,101,032	(94,893)	(327,161)	(422,054)	-7.8%	-25.2%	-16.7%
Total C&I	43,335,032	30,144,581	73,479,613	47,127,106	37,177,200	84,304,306	3,792,074	7,032,619	10,824,693	8.8%	23.3%	14.7%
Group Metered Apartment												
H/C < 3,075	498,345	428,385	926,730	566,702	432,477	999,179	68,357	4,092	72,449	13.7%	1.0%	7.8%
H/C > 3,075	18,852,108	9,291,257	28,143,365	20,493,631	9,180,472	29,674,103	1,641,523	(110,785)	1,530,738	8.7%	-1.2%	5.4%
Non H/C	1,434,864	2,561,379	3,996,243	1,551,590	2,378,258	3,929,848	116,726	(183,121)	(66,395)	8.1%	-7.1%	-1.7%
Total GMA	20,785,317	12,281,021	33,066,338	22,611,923	11,991,207	34,603,130	1,826,606	(289,814)	1,536,792	8.8%	-2.4%	4.6%
Total Firm	137,678,020	57,119,037	194,797,057	142,065,096	64,016,660	206,081,756	4,387,076	6,897,623	11,284,699	3.2%	12.1%	5.8%
Non-Firm												
Interruptible	16,895,943	26,246,172	43,142,115	15,911,005	23,916,786	39,827,791	(984,938)	(2,329,386)	(3,314,324)	-5.8%	-8.9%	-7.7%
Special Contracts	11,037,825	26,728,720	37,766,545	10,878,939	27,341,796	38,220,735	(158,886)	613,076	454,190	-1.4%	2.3%	1.2%
Total Non-Firm	27,933,768	52,974,892	80,908,660	26,789,944	51,258,582	78,048,526	(1,143,824)	(1,716,310)	(2,860,134)	-4.1%	-3.2%	-3.5%
Total Throughput	165,611,788	110,093,929	275,705,717	168,855,040	115,275,242	284,130,282	3,243,252	5,181,313	8,424,565	2.0%	4.7%	3.1%

Washington Gas Light Company

DC PSC Formal Case No. 1180

Analysis of WG Peak Day Estimates for Base Gas and Weather Sensitive Gas - FC 1169 vs FC 1180

	FC 1169 - WG Estimates Peak Day Requirements			FC 1180 - WG Estimates Peak Day Requirements			Difference FC 1180 - FC 1169 Peak Day Requirements			Difference FC 1180 - FC 1169 Peak Day Requirements		
	Weather Gas	Base Gas	Total Peak Day	Weather Gas	Base Gas	Total Peak Day	Weather Gas	Base Gas	Total Peak Day	Weather Gas	Base Gas	Total Peak Day
Residential												
H/C	1,213,965	38,021	1,251,986	1,138,887	36,521	1,175,408	(75,078)	(1,500)	(76,578)	-6.2%	-3.9%	-6.1%
Non H/C - IMA	5,776	1,057	6,833	4,978	987	5,965	(798)	(70)	(868)	-13.8%	-6.6%	-12.7%
Non H/C	20,937	1,112	22,049	20,770	1,126	21,896	(167)	14	(153)	-0.8%	1.3%	-0.7%
Total Residential	1,240,678	40,190	1,280,868	1,164,635	38,634	1,203,269	(76,043)	(1,556)	(77,599)	-6.1%	-3.9%	-6.1%
Commercial & Industrial												
H/C < 3,075	70,985	1,756	72,741	65,270	3,468	68,738	(5,715)	1,712	(4,003)	-8.1%	**97.5%**	-5.5%
H/C > 3,075	596,399	55,987	652,386	633,771	81,489	715,260	37,372	25,502	62,874	6.3%	**45.5%**	9.6%
Non H/C	47,011	11,304	58,315	44,047	13,896	57,943	(2,964)	2,592	(372)	-6.3%	22.9%	-0.6%
CHP	20,642	3,314	23,956	18,146	2,616	20,762	(2,496)	(698)	(3,194)	-12.1%	-21.1%	-13.3%
Total C&I	735,037	72,361	807,398	761,234	101,469	862,703	26,197	29,108	55,305	3.6%	40.2%	6.8%
Group Metered Apartment												
H/C < 3,075	8,405	1,356	9,761	9,042	1,160	10,202	637	(196)	441	7.6%	-14.5%	4.5%
H/C > 3,075	318,145	23,649	341,794	330,407	24,735	355,142	12,262	1,086	13,348	3.9%	4.6%	3.9%
Non H/C	24,124	6,482	30,606	24,953	6,347	31,300	829	(135)	694	3.4%	-2.1%	2.3%
Total GMA	350,674	31,487	382,161	364,402	32,242	396,644	13,728	755	14,483	3.9%	2.4%	3.8%
Total Firm	2,326,389	144,038	2,470,427	2,290,271	172,345	2,462,616	(36,118)	28,307	(7,811)	-1.6%	19.7%	-0.3%
Non-Firm												
Interruptible	286,544	67,192	353,736	254,561	63,953	318,514	(31,983)	(3,239)	(35,222)	-11.2%	-4.8%	-10.0%
Special Contracts	186,345	68,116	254,461	175,043	73,499	248,542	(11,302)	5,383	(5,919)	-6.1%	7.9%	-2.3%
Total Non-Firm	472,889	135,308	608,197	429,604	137,452	567,056	(43,285)	2,144	(41,141)	-9.2%	1.6%	-6.8%
Total Throughput	2,799,278	279,346	3,078,624	2,719,875	309,797	3,029,672	(79,403)	30,451	(48,952)	-2.8%	10.9%	-1.6%

Washington Gas Light Company

DCPSC Formal Case No. 1180

Development of AOBA Proposed Charges for C&I and GMA Customers

	Months Billed	Current Charge	Current Revenue	WG Proposed Charge	WG Proposed Revenue	% Incr.	AOBA Proposed Charge	AOBA Proposed Revenue	AOBA Change from WG Proposal	% Chg from WG Prop	AOBA % Chg from Current Rates
Customer Charge											
C&I Htg/Clg < 3075	53,982	$ 29.90	$ 1,614,062	$ 37.40	$ 2,018,927	25.1%	$ 37.50	$ 2,024,325	$ 5,398	0.3%	25.4%
C&I Htg/Clg < 3075	40,679	$ 70.05	$ 2,849,564	$ 87.55	$ 3,561,445	25.0%	$ 86.00	$ 3,498,394	$ (63,051)	-1.8%	22.8%
C&I Non-Htg	22,135	$ 28.50	$ 630,848	$ 35.65	$ 789,113	25.1%	$ 37.50	$ 830,063	$ 40,950	5.2%	31.6%
	116,796		$ 5,094,474	$ 54.54	$ 6,369,485	25.0%		$ 6,352,782	$ (16,704)		24.7%
GMA Htg/Clg < 3075	7,177	$ 28.50	$ 204,545	$ 35.65	$ 255,860	25.1%	$ 37.50	$ 269,138	$ 13,278	5.2%	31.6%
GMA Htg/Clg < 3075	20,485	$ 70.05	$ 1,434,974	$ 87.60	$ 1,794,486	25.1%	$ 86.00	$ 1,761,710	$ (32,776)	-1.8%	22.8%
GMA Non-Htg	10,430	$ 28.50	$ 297,255	$ 35.65	$ 371,830	25.1%	$ 37.50	$ 391,125	$ 19,295	5.2%	31.6%
Total	38,092		$ 1,936,774	$ 63.59	$ 2,422,176	25.1%		$ 2,421,973	$ (204)	0.0%	25.1%

	Therms	Current Charge	Current Revenue	Proposed $/Therm	Proposed Revenue	% Incr.	AOBA Proposed Charge	AOBA Proposed Revenue	AOBA Change from WG Proposal	% Chg from WG Prop	AOBA % Chg from Current Rates
Peak Usage Charge											
C&I Htg/Clg < 3075	4,713,270	0.0519	$ 244,619	$ 0.0692	$ 326,158	33.3%	$ 0.0540	$ 254,631	$ (71,527)	-21.9%	4.1%
C&I Htg/Clg < 3075	57,199,008	0.0421	$ 2,408,078	$ 0.0532	$ 3,042,967	26.4%	$ 0.0540	$ 3,090,132	$ 47,165	1.5%	28.3%
C&I Non-Htg	6,999,042	0.0423	$ 296,059	$ 0.0534	$ 373,778	26.3%	$ 0.0540	$ 378,118	$ 4,340	1.2%	27.7%
Total	68,911,320		$ 2,948,756		$ 3,742,903			$ 3,722,881	$ (20,022)		26.3%
GMA Htg/Clg < 3075	690,138	0.0431	$ 29,745	$ 0.0544	$ 37,543	26.2%	$ 0.0540	$ 37,284	$ (259)	-0.7%	25.3%
GMA Htg/Clg < 3075	25,256,574	0.0422	$ 1,065,827	$ 0.0533	$ 1,346,175	26.3%	$ 0.0540	$ 1,364,467	$ 18,292	1.4%	28.0%
GMA Non-Htg	3,187,206	0.0423	$ 134,819	$ 0.0534	$ 170,197	26.2%	$ 0.0540	$ 172,186	$ 1,989	1.2%	27.7%
Total	29,133,918		1,230,391	$ 0.0533	1,553,915	26.3%		1,573,937	20,022	1.3%	27.9%
Distribution Charge											
C&I Htg/Clg < 3075	5,336,138	$ 0.5821	$ 3,106,166	0.8010	$ 4,274,246	37.6%	0.6180	$ 3,297,733	$ (976,513)	-22.8%	6.2%
C&I Htg/Clg < 3075	68,854,404	$ 0.4796	$ 33,022,572	0.6063	$ 41,746,425	26.4%	0.6180	$ 42,552,022	$ 805,597	1.9%	28.9%
C&I Non-Htg	8,012,732	$ 0.4811	$ 3,854,925	0.6087	$ 4,877,350	26.5%	0.6180	$ 4,951,868	$ 74,518	1.5%	28.5%
Total	82,203,274		39,983,663	$ 0.6192	50,898,021	27.3%		50,801,623	(96,398)		27.1%
GMA Htg/Clg < 3075	999,179	$ 0.4930	$ 492,595	0.6252	$ 624,686	26.8%	0.6180	$ 617,493	$ (7,193)	-1.2%	25.4%
GMA Htg/Clg < 3075	29,674,103	$ 0.4863	$ 14,430,516	0.6148	$ 18,243,638	26.4%	0.6180	$ 18,338,596	$ 94,958	0.5%	27.1%
GMA Non-Htg	3,929,848	$ 0.4841	$ 1,902,439	0.6124	$ 2,406,639	26.5%	0.6180	$ 2,428,646	$ 22,007	0.9%	27.7%
Total	34,603,130		16,825,551	$ 0.6148	21,274,963	26.4%		21,384,734	109,771	0.5%	27.1%

Attachment A
Resume of Bruce R. Oliver
Formal Case No. 1180

BRUCE R. OLIVER

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(703) 569-6480

EXPERIENCE

Over 45 years of experience specializing in the areas of utility rates, energy, and regulatory policy. Offers unusual depth and breadth in his understanding of energy and utility industries which leads to creative and effective resolution of rate issues. Has presented expert testimony in regulatory proceedings in more than 300 proceedings before regulatory commissions in 26 jurisdictions and has served a diverse group of clients on issues encompassing a wide range of energy and utility-related activities. Assists clients in the assessment of competitive energy markets for retail services and in the negotiation of contracts for the purchase of such services. Clients have included commercial and industrial energy users, hospitals and universities, state regulatory commissions, utilities, consumer advocates, municipal governments, federal agencies, and suppliers of equipment and services to utility markets.

1985-Present Revilo Hill Associates, Inc.
President and CEO

Directs the firm's consulting practice, with specialization in the areas of industrial economics, energy, utilities, and regulatory policy. Provides expert testimony in regulatory proceedings. Assists individual commercial and institutional customers in the competitive procurement of energy services and resolution of utility service and billing issues. Regulatory work includes participation in electric, gas, water and sewer utility rate and policy matters, with particular specialization in the areas of utility costs of service, rate structure, rate of return, utility planning, and forecasting. Examples of projects include:

- Development and presentation of positions regarding the merits of various forms of alternative ratemaking including but not limited to: multi-year rate plans; performance-based ratemaking concepts; and the merits of proposals for Performance Incentive Mechanisms.

- Assessment of a gas distribution utility's plans for accelerated replacement of aging and leak prone distribution mains by an LDC, as well as the impacts of rising leak rates the utility's gas system safety and rates distribution services.

- Negotiation of settlements to reflect the impacts of the Tax Cut and Jobs Act of 2017 in rates for certain electric and gas distribution utilities.

- Investigation of gas and electric utility merger issues including ring-fencing, costs to achieve, estimated merger benefits, and allocation of merger benefits among customers for electric and gas utility mergers.

- Investigation of gas distribution utility system expansion proposals, tariff changes, and proposed ratemaking treatment of costs for gas expansion activities.

- Examination of utility proposals undergrounding overhead electric distribution facilities and the recovery of costs for undergrounding activities.

- Evaluation of utility proposals for the deployment of Advanced Metering Infrastructure (AMI) and the development of dynamic pricing rates to be implemented using AMI equipment.

- Detailed evaluation of a gas distribution utility's long-range gas supply planning, its evaluation of gas supply alternatives, and the prudence of gas its procurement decisions.

- Investigation of cost of service, rate design, tariff, forecasting and planning issues for island utilities in the U.S. Virgin Islands and Guam.

- Analysis of utility revenue decoupling proposals including assessment of the cost of service and rate impacts of such proposals and the development of appropriate tariff language for such proposals.

- Investigation of matters relating to a utility's outsourcing of significant components of its Administrative and General and Customer Service activities, including the merits of the proposed outsourcing arrangements and the rate treatment of costs incurred to select providers of outsourced services; negotiate contracts; and achieve the implementation of outsourcing arrangements.

- Strategic analysis and policy guidance for a major commercial consumer group in the development and presentation of positions before legislative and regulatory bodies regarding electric and gas regulatory issues.

- Development of Asset Management incentive programs for natural gas distribution utilities.

- Investigation and preparation of a report on the causes of large heating oil price increases for the Attorney General of a New England state.

- Participation as a member of a three-person panel hearing a gas marketer complaint of anti-competitive behavior by a local gas distribution utility in its provision of unbundled gas transportation services.

- Preparation of cost allocation studies and rate structure proposals for electric, gas, water, and wastewater utility regulatory proceedings;

- Analysis of proposals for restructuring and the unbundling of rates for local gas distribution companies, and negotiated terms, conditions, and pricing for restructured utility services.

2000-Present — AOBA Alliance, Inc.
Director and Chief Economist

Key technical advisor to one of the nation's largest and most successful customer-based energy aggregation programs. Assists non-residential customers in the Washington, D.C. area in the procurement of competitive retail energy services, including the evaluation and negotiation of contract terms for competitive electricity, natural gas, energy information services. Monitors energy markets and keeps participants informed regarding energy market developments and pricing trends. Focused primarily on the commercial building industry, the AOBA Alliance, Inc. serves more than 11,000 electric and natural gas accounts in twelve states and the District of Columbia. Those participants use over 4.0 billion kWh per year and over 900 MW of electrical peak load.

1981-85 — Resource Dynamics Corporation
Principal and Vice President

Responsible for the firm's activities in the areas of energy pricing, utility rates and regulatory policy. Provided expert testimony before utility regulatory commissions on issues relating to costs of service, rate design, load management, load research, fuel price forecasting, utility costing analyses, and cost allocation methods. Evaluated utility fuel procurement practices, fuel price forecasts, and price forecasting methodologies. Contributed to modeling efforts relating to the estimation of national and regional electric utility load curves and coal market prices. Participated in the development handbooks for cogeneration feasibility assessment.

1980-81 Potomac Electric Power Company
Manager of Rate Research Department

Directed the development of all rate related programs. Supervised the costing, design, and analysis of traditional and innovative rates (including time-of-use, load management and cogeneration tariffs). Also was responsible for corporate revenue forecasting activities, as well as the development of marginal and avoided cost studies.

1979-80 Pacific Gas and Electric Company
Rate Experimentation Supervisor

Responsible for design, implementation, and analysis of innovative rate programs for both gas and electric service. Developed programs for curtailable service; cogeneration; conservation; residential load cycling; and commercial, industrial, and agricultural time-of- use rates. Directed analyses of time-of-use and lifeline price elasticities and development of marginal and avoided costing methods.

1973-79 ICF Incorporated
Project Manager

Specialized in energy policy and utility regulatory analyses. Performed detailed analysis of U.S. petroleum, natural gas, coal, and electric utility industries. Provided expert testimony on utility rate issues. Designed experimental rates for federally funded time-of-use rate and load management programs in North Carolina. Provided technical support to the DOE Regulatory Intervention Program. Contributed to the design and development of the National Coal Model, and prepared forecasts of low sulfur fuel availability for utility markets.

1972-73 U.S. Cost-of-Living Council - Pay Board
Labor Economist

Served in the Office of the Chief Economist. Responsible for macroeconomic analyses of Board decisions, and for the development data systems to support assessments of the impacts of Board decisions and the reporting of aggregate statistics on wage increases granted by the Board.

EDUCATION

1972 M.A., Economics, Virginia Polytechnic Institute and State University

1970 B.A., Economics, Virginia Polytechnic Institute and State University

RATE CASE PARTICIPATION

Alberta, Canada

Canadian Western Natural Gas	1998 General Rate Application
NOVA Gas Transmission Ltd.	1995 GRA, Phase II
Canadian Western Natural Gas	Core Market Direct Purchase
Northwestern Utilities	Core Market Direct Purchase
TransAlta Utilities Corp.	Load Retention Rate Offering
Alberta Power Ltd.	1993 General Rate Application

Arizona

Southwest Gas Corporation	Docket No. U-1551-93-272
Sun City Water Company	Docket No. U-1656-91-134
Havasu Water Company	Docket No. U-2013-91-133
Arizona Water Company	Docket No. U-1445-91-227

California

Pacific Gas & Electric Company	Application No. 58089

Connecticut

Southern Connecticut Gas Company	Docket No. 89-09-06
Connecticut Light & Power Company	Docket No. 87-07-01

Delaware

Chesapeake Utilities Corporation	Docket No. 95 - 73
Delmarva Power & Light Company	Docket No. 94 - 141
Delmarva Power & Light Company	Docket No. 94 - 129
Delaware Electric Cooperative	Docket No. 94 - 100
Delmarva Power & Light Company	Docket No. 92 - 85
Delmarva Power & Light Company	Docket No. 92 - 71F
Delaware Electric Cooperative	Docket No. 91 - 37
Delmarva Power & Light Company	Docket No. 91 - 24
Delmarva Power & Light Company	Docket No. 91 - 20
Delmarva Power & Light Company	Docket No. 90 - 31
Delmarva Power & Light Company	Docket No. 90 - 21
Delmarva Power & Light Company	Docket No. 89 - 26
Chesapeake Utilities Corporation	Docket No. 88 - 39F
Delmarva Power & Light Company	Docket No. 88 - 34
Delmarva Power & Light Company	Docket No. 88 - 32, Phase 2
Delmarva Power & Light Company	Docket No. 88 - 32
Delaware Electric Cooperative	Docket No. 87 - 34, Phase 2
Delaware Electric Cooperative	Docket No. 87 - 34
Delmarva Power & Light Company	Docket No. 87 - 9, Phase 5
Delmarva Power & Light Company	Docket No. 87 - 9, Phase 4
Delmarva Power & Light Company	Docket No. 87 - 9, Phase 3

Delmarva Power & Light Company	Docket No. 87 - 9, Phase 2
Delmarva Power & Light Company	Docket No. 87 - 9
Delmarva Power & Light Company	Docket No. 86 - 43
Delmarva Power & Light Company	Docket No. 86 - 24

District of Columbia

Potomac Electric Power Company	Formal Case No. 1176
Washington Gas Light Company	Formal Case No. 1169
Washington Gas Light Company	Formal Case No. 1162
Potomac Electric Power Company	Formal Case No. 1156
Potomac Electric Power Company	Formal Case No. 1151
Potomac Electric Power Company	Formal Case No. 1150
Potomac Electric Power Company	Formal Case No. 1145
WGL – AltaGas Merger	Formal Case No. 1142
Potomac Electric Power Company	Formal Case No. 1139
Washington Gas Light Company	Formal Case No. 1137
Potomac Electric Power Company	Formal Case No. 1133
Potomac Electric Power Company	Formal Case No. 1130
Potomac Electric Power Company	Formal Case No. 1121
Exelon – Pepco Merger	Formal Case No. 1119
Potomac Electric Power Company	Formal Case No. 1116
Washington Gas Light Company	Formal Case No. 1115
Potomac Electric Power Company	Formal Case No. 1103
Washington Gas Light Company	Formal Case No. 1093
Potomac Electric Power Company	Formal Case No. 1087
Washington Gas Light Company	Formal Case No. 1079
Potomac Electric Power Company	Formal Case No. 1076
Potomac Electric Power Company	Formal Case No. 1056
Washington Gas Light Company	Formal Case No. 1054
Potomac Electric Power Company	Formal Case No. 1053, Phase II
Potomac Electric Power Company	Formal Case No. 1053
Washington Gas Light Company	Formal Case No. 1016
Potomac Electric Power/Conectiv Merger	Formal Case No. 1002
Washington Gas Light Company	Formal Case No. 989
Potomac Electric Power Company/Baltimore Gas & Electric Company Merger	Formal Case No. 951
Potomac Electric Power Company	Formal Case No. 945
Potomac Electric Power Company	Formal Case No. 939
Washington Gas Light Company	Formal Case No. 934
Washington Gas Light Company	Formal Case No. 922
District of Columbia Natural Gas	Formal Case No. 890
Potomac Electric Power Company	Formal Case No. 889
Potomac Electric Power Company	Formal Case No. 869
District of Columbia Natural Gas	Formal Case No. 845
District of Columbia Natural Gas	Formal Case No. 840
Potomac Electric Power Company	Formal Case No. 834

Potomac Electric Power Company	Formal Case No. 813, Phase II
Potomac Electric Power Company	Formal Case No. 813
Washington Gas Light Company	Formal Case No. 787
Potomac Electric Power Company	Formal Case No. 785
Potomac Electric Power Company	Formal Case No. 759, Phases III
Potomac Electric Power Company	Formal Case No. 759, Phases II
Potomac Electric Power Company	Formal Case No. 759, Phases I
Potomac Electric Power Company	Formal Case No. 758

Guam

Guam Power Authority	Docket No. 11-090, Phase II
Guam Power Authority	Docket No. 11-090
Guam Power Authority	Docket No. 07-010
Guam Power Authority	Docket No. 98-002
Guam Power Authority	Docket No. 96-004
Guam Power Authority	Docket No. 95-001
Guam Power Authority	Docket No. 94-001
Guam Power Authority	Docket No. 92-002
Guam Power Authority	Docket No. 89-002 A,B,C

Illinois

Commonwealth Edison Company	Docket No. 86-0128

Maryland

Washington Gas Light Company	Case No. 9704
Potomac Electric Power Company	Case No. 9702
Potomac Electric Power Company	Case No. 9655
Washington Gas Light Company	Case No. 9651
Generic – Alternative Ratemaking	Case No. 9618
Washington Gas Light Company	Case No. 9605
Potomac Electric Power Company	Case No. 9602
Washington Gas Light Company	Case No. 9486
Washington Gas Light Company	Case No. 9481
Washington Gas Light Company	Case No. 9473
Potomac Electric Power Company	Case No. 9472
WGL – AltaGas Merger	Case No. 9449
Potomac Electric Power Company	Case No. 9443
Washington Gas Light Company	Case No. 9433
Potomac Electric Power Company	Case No. 9418
Exelon – Pepco Merger	Case No. 9361
Potomac Electric Power Company	Case No. 9336
Washington Gas Light Company	Case No. 9335
Washington Gas Light Company	Case No. 9322
Potomac Electric Power Company	Case No. 9311
Potomac Electric Power Company	Case No. 9286
Washington Gas Light Company	Case No. 9267

Potomac Electric Power Company	Case No. 9217
Potomac Electric Power Company	Case No. 9207
Washington Gas Light Company	Case No. 9158
Washington Gas Light Company	Case No. 9104, Phase II
Washington Gas Light Company	Case No. 9104
Potomac Electric Power Company	Case No. 9092, Phase II
Potomac Electric Power Company	Case No. 9092
Standard Offer Service Docket	Case No. 9063
Standard Offer Service Docket	Case No. 9056
Standard Offer Service Docket	Case No. 9037
Potomac Electric Power Company	Case No. 8895
Washington Gas Light Company	Case No. 8991
Washington Gas Light Company	Case No. 8959
Washington Gas Light Company	Case No. 8920, Phase II
Washington Gas Light Company	Case No. 8920
Potomac Electric Power Company	Case No. 8895
Potomac Electric Power Company	Case No. 8890
Washington Gas Light Company	Case No. 8819
Potomac Electric Power Company	Case No. 8791
Potomac Electric Power Company	Case No. 8773
Generic Electric Industry Restructuring	Case No. 8738
Potomac Electric Power Company/Baltimore Gas & Electric Company Merger	Case No. 8725
Washington Gas Light Company	Case No. 8545
Potomac Electric Power Company	Case No. 8315
Potomac Electric Power Company	Case No. 8251
Maryland Natural Gas	Case No. 8191
Potomac Electric Power Company	Case No. 8162
Maryland Natural Gas	Case No. 8119
Potomac Electric Power Company	Case No. 8079
Baltimore Gas & Electric Company	Case No. 8070
Maryland Natural Gas	Case No. 8060
Potomac Electric Power Company	Case No. 7972
Potomac Electric Power Company	Case No. 7874
Washington Gas Light Company	Case No. 7649

Massachusetts

Investigation of Rate Structures to Promote Efficient Deployment of Demand Management	Docket No. 07-50

North Carolina

Generic Electric Load Management	Docket No. M100, Sub 78

New Jersey

Public Service Electric and Gas	Docket No. GT93060242
Public Service Electric and Gas	Docket No. ER91111698J

Elizabethtown Gas Company	Docket No. 8812-1231
Elizabethtown Gas Company	Docket No. 8612-1374
Public Service Electric and Gas	Docket No. 8512-1163
Jersey Central Power & Light	Docket No. 8511-1116
New Jersey Natural Gas Company	Docket No. 8510-974
South Jersey Gas Company	Docket No. 850-8858
Public Service Electric and Gas	Docket No. 850-2231
New Jersey Natural Gas Company	Docket No. 850-7732
South Jersey Gas Company	Docket No. 843-184, Phase II
Atlantic Electric Company	Docket No. 8310-883, Phase II
New Jersey Natural Gas Company	Docket No. 831-46
Public Service Electric and Gas	Docket No. 837-620
Public Service Electric and Gas	Docket No. 8210-869

New Mexico

Gas Company of New Mexico	Case No. 2353
Gas Company of New Mexico	Case No. 2340
Gas Company of New Mexico	Case No. 2307
Gas Company of New Mexico	Case No. 2183
Gas Company of New Mexico	Case No. 2147 (Remand)
Gas Company of New Mexico	Case No. 2147
Gas Company of New Mexico	Case No. 2093

New York

Consolidated Edison Company	Docket No. 94-E-0334
Consolidated Edison Company	Docket No. 91-E-0462
Brooklyn Union Gas Company	Docket No. 90-G-0981

Ohio

Toledo Edison Company	Case No. 78-628-EL-FAC

Pennsylvania

PECO Energy Company	Docket No. R-20028394
PG Energy, Inc.	Docket No. R-00061365
Philadelphia Electric Company	Docket No. R-00970258
Mechanicsburg Water Company	Docket No. R-00922502
West Penn Power Company	Docket No. R-00922378
Pennsylvania Electric Company	Docket No. M-920312
North Penn Gas Company	Docket No. R-922276
Metropolitan Edison Company	Docket No. R-922314
York Water Company	Docket No. R-922168
Dauphin Consolidated Water Company	Docket No. R-921000
Pennsylvania Electric Company	Docket No. M-920312
Duquesne Light Company	Docket No. C-913424
Pennsylvania American Water Company	Docket No. R-911909
West Penn Power Company	Docket No. R-901609

Pennsylvania Gas & Water Co. Water Div.	Docket No. R-891209
Pennsylvania Power Company	Docket No. R-881112
Duquesne Light Company	Docket No. R-870651
Pennsylvania Electric Company	Docket No. R-870172
Metropolitan Edison Company	Docket No. R-870171
Western Pennsylvania Water Company	Docket No. R-860397
Duquesne Light Company	Docket No. R-860378
Philadelphia Electric Company	Docket No. R-850290
Pennsylvania Power Company	Docket No. R-850267
Pennsylvania Power & Light Company	Docket No. R-850251
Philadelphia Electric Company	Docket No. R-850152
Western Pennsylvania Water Company	Docket No. R-850096
Pennsylvania Power Company	Docket No. R-842740
Pennsylvania Power & Light Company	Docket No. R-842651
Pennsylvania Electric Company	Docket No. R-832550
Metropolitan Edison Company	Docket No. R-832549
Duquesne Light Company	Docket No. R-842383
UGI Corporation-Gas Utility Division	Docket No. R-832331
Pennsylvania Power & Light Company	Docket No. I-830374
Pennsylvania Electric Company	Docket No. R-822250
Metropolitan Edison Company	Docket No. R-822249
Pennsylvania Power & Light Company	Docket No. R-822169
Pennsylvania Gas & Water Co. - Water Div.	Docket No. R-822102
Columbia Gas Co. of Pennsylvania	Docket No. R-822042
Pennsylvania Gas & Water Co. - Gas Div.	Docket No. R-821961
Philadelphia Electric Company	Docket No. R-811626

Philadelphia, City of

Philadelphia Gas Works	1992 Rate Design Proceeding
Philadelphia Water Department	1992 Rate Increase Request
Philadelphia Gas Works	1990 Rate Increase Request
Philadelphia Water Department	1990 Rate Increase Request
Philadelphia Gas Works	1989 Proceeding
Philadelphia Gas Works	1988 Rate Increase Request
Philadelphia Gas Works	1987-88 Operating Budget
Philadelphia Gas Works	1986 Rate Increase Request
Philadelphia Water Department	1985 Rate Increase Request

Rhode Island – Public Utilities Commission

Narragansett Electric Company d/b/a RI Energy	Docket No. 22-42-NG
National Grid – Gas Long-Range Plan	Docket No. 4872
National Grid – Gas GCR	Docket No. 4846
National Grid – Gas DAC	Docket No. 4816

National Grid – Gas Annual ISR Filing	Docket No. 4781
National Grid – Gas Base Rates	Docket No. 4770
National Grid – Gas GCR	Docket No. 4719
National Grid – Gas DAC	Docket No. 4708
National Grid – Gas GCR	Docket No. 4647
National Grid – Gas DAC	Docket No. 4634
National Grid – Gas Long-Range Plan	Docket No. 4608
National Grid – Gas GCR	Docket No. 4576
National Grid – Gas DAC	Docket No. 4573
National Grid – Gas Customer Choice	Docket No. 4523
National Grid – Gas GCR	Docket No. 4520
National Grid – Gas DAC	Docket No. 4514
National Grid – Gas GCR	Docket No. 4436
National Grid – Gas DAC	Docket No. 4431
National Grid – Gas GCR	Docket No. 4346
National Grid – Gas DAC	Docket No. 4339
National Grid – Gas On-System Margins	Docket No. 4333
National Grid – Gas Base Rates	Docket No. 4323
National Grid – Gas GCR	Docket No. 4283
National Grid – Gas DAC	Docket No. 4269
National Grid – Electric Backup Service	Docket No. 4232
National Grid – Elec & Gas Revenue Decoupling	Docket No. 4206
National Grid – Gas GCR	Docket No. 4199
National Grid – Gas DAC	Docket No. 4196
National Grid – Gas GCR	Docket No. 4097
National Grid – Gas DAC	Docket No. 4077
National Grid – Electric	Docket No. 4065
National Grid – Gas Portfolio Management	Docket No. 4038
National Grid – Gas GCR	Docket No. 3982
National Grid – Gas DAC	Docket No. 3977
National Grid – Gas GCR	Docket No. 3961
National Grid – Gas Base Rates	Docket No. 3943
National Grid – Gas GCR	Docket No. 3868
National Grid – Gas DAC	Docket No. 3859
National Grid – Gas Long-Range Plan	Docket No. 3789
National Grid – Gas GCR	Docket No. 3766
National Grid – Gas DAC	Docket No. 3760
New England Gas Company	Docket No. 3696
New England Gas Company	Docket No. 3690
Block Island Power Company	Docket No. 3655
New England Gas Company	Docket No. 3548
New England Gas Company	Docket No. 3459
New England Gas Company	Docket No. 3436
New England Gas Company	Docket No. 3401
Providence Gas Company	Docket No. 3295
Narragansett Electric Company	Docket No. 2930

Providence Gas Company	Docket No. 2902
Providence Gas Company	Docket No. 2581
Providence Gas Company	Docket No. 2552
Providence Gas Company	Docket No. 2374
Providence Gas Company	Docket No. 2286
Valley Gas Company	Docket No. 2276
Valley Gas Company	Docket No. 2138, Phase II
Valley Gas Company	Docket No. 2138, Phase I
Providence Gas Company	Docket No. 2082
Providence Gas Company	Docket No. 2076
Providence Gas Company	Docket No. 2001, Phase II
Valley Gas Company	Docket No. 2038
Providence Gas Company	Docket No. 2001
Block Island Power Company	Docket No. 1998
Providence Gas Company	Docket No. 1971
Generic Gas Transportation	Docket No. 1951
Valley Gas Company	Docket No. 1736
Providence Gas Company	Docket No. 1723
Providence Gas Company	Docket No. 1673

Rhode Island – Division of Public Utilities

PPL Acquisition of National Grid's Rhode Island Assets	Docket No. D-21-09
National Grid Acquisition of New England Gas Company's Rhode Island Assets	Docket No. D-06-13
Merger of Southern Union, Valley Gas Company And Bristol & Warren Gas Company	Docket No. D-00-02

South Dakota

Northern States Power Company	Docket No. F-3188

Utah

Dominion Energy Utah	Docket No. 19-057-02

Vermont

Department of Public Service	Docket No. 5378
Department of Public Service	Docket No. 5307

Virginia

Virginia Electric Power Company	Docket No. PUE 2021-00058
Washington Gas Light Company	Docket No. PUR 2018-00080
Virginia Electric Power Company	Docket No. PUE 2018-00042
AltaGas – WGL Merger	Docket No. PUR 2017-00049

Virginia Electric Power Company	Docket No. PUE 2016-00021
Virginia Electric Power Company	Docket No. PUE 2016-00001
Virginia Electric Power Company	Docket No. PUE 2015-00027
Virginia Electric Power Company	Docket No. PUE 2011-00027
Washington Gas Light Company	Docket No. PUE 2010-00139
Virginia Electric Power Company	Docket No. PUE 2009-00019
Virginia Electric Power Company	Docket No. PUE 2009-00018
Virginia Electric Power Company	Docket No. PUE 2009-00017
Virginia Electric Power Company	Docket No. PUE 2009-00016
Virginia Electric Power Company	Docket No. PUE 2009-00011
Washington Gas Light Company	Docket No. PUE 2006-00059
Washington Gas Light Company	Docket No. PUE 2005-00010
Washington Gas Light Company	Docket No. PUE 2003-00603
Washington Gas Light Company	Docket No. PUE 2002-00364
Virginia Electric Power Company	Docket No. PUE 000584
Virginia Electric Power Company	Docket No. PUE 980213
Virginia Electric Power Company	Docket No. PUE 980212
Virginia Electric Power Company	Docket No. PUE 960296
Washington Gas Light Company	Docket No. PUE 940031
Virginia Electric Power Company	Docket No. PUE 920041
Virginia Electric Power Company	Docket No. PUE 910047
Northern Virginia Natural Gas	Docket No. PUE 900016
Northern Virginia Natural Gas	Docket No. PUE 880024
Virginia Electric Power Company	Docket No. PUE 830029
Washington Gas Light Company	Docket No. PUE 830008

Virgin Islands

Water and Power Authority – Water Rates	Docket No. 613
Water and Power Authority – Electric Rates	Docket No. 612
Water and Power Authority – Water Rates	Docket No. 576
Water and Power Authority – Electric Rates	Docket No. 575
Water and Power Authority – Electric Rates	Docket No. 533

Wisconsin

Gas Transportation - Generic	Docket No. 05-GI-102

Federal Energy Regulatory Commission

Weaver's Cove Energy, LLC.	Docket No. CP04-36-000
Mill River Pipeline, LLC.	Docket No. CP04-41-000
Columbia Gulf Transmission Co.	Docket No. RP86-167-000
Columbia Gas Transmission Corp.	Docket No. RP86-168-000
Columbia Gulf Transmission Co.	Docket No. TC86-021-000

<u>SELECTED REPORTS, PUBLICATIONS AND PRESENTATIONS</u>

"*Post-Pandemic Energy Procurement,*" Presentation to AOBA Utility Committee, April 7, 2022.

"AOBA Presentation for the Third Bill Stabilization Technical Conference," District of Columbia Public Service Commission, Technical Conference, Formal Case No. 1156, January 20, 2022.

"*AOBA Presentation for the Second Bill Stabilization Technical Conference*," Formal Case No 1156, December 9, 2021.

"*The Evolution of the Energy Utility Industry, the Rise of Public Utility Holding Companies, and the Clash of Utility and Political Economics*," Presentation to the Virginia Polytechnic and State University, Department of Economics, April 8, 2021.

"*Contracting for Renewable Energy in Virginia*," Presentation for AOBA Alliance, November 20, 2019.

"*Perspectives on Alternative Forms of Regulation*," AOBA Presentation for District of Columbia Public Service Commission, Technical Conference, Formal Case No. 1156, October, 2019.

"*AOBA Utility and Energy market Update: DC, Maryland, and Virginia,"* presentation of the AOBA Utility Committee, August 18, 2016.

"*The Case Against Continuation of Pepco's DC Undergrounding Project*," April 26, 2016, CONFIDENTIAL.

"*Pepco DC Undergrounding Update*," Presentation to the AOBA Board of Directors, November, 20, 2014.

"*Economics, Character, and Courage* are Necessary to Sustain Free Markets and a Free Society, Virginia Polytechnic and State University, Department of Economics, Commencement Address, May 17, 2014.

"*Will Energy Market Developments Drive Government Policy or Will Government Policy Drive Energy Markets*," Presentation to AOBA Utility Committee, June 27, 2013.

"Ratemaking for Recovery of Pipeline Safety Investments," Presentation to the National Association of Regulatory Utility Commissioners, February 6, 2013.

"In Comparatively Stable Energy Markets, Legislative and Regulatory Decisions Make Budgeting for Energy Services A Real Challenge," Presentation to AOBA Utility Committee, October 19, 2011.

"*Energy Commodities Show Stability; Charges for Utility Services Rise*," Presentation to AOBA Utility Committee, April 20, 2011.

"*Budgeting for Utilities In the Face of Constantly Changing Rates*," Presentation to AOBA Utility Committee, November 10, 2010.

"*Electric Utilities Seek Increased Rates to Fund Large Construction Projects*," Presentation to AOBA Utility Committee, October 7, 2009.

"*Could You Soon Be Paying $1.00 per kWh for Peak Electricity Supply?*" Presentation to AOBA Utility Committee, June 24, 2009.

"*Energy Markets in a Tailspin*," Presentation to AOBA Utility Committee, March 11, 2009.

"*Energy price Outlook for 2009*," Presentation to AOBA Utility Committee, December 10, 2008.

"*Are You 'Going Green' or Going in the Red*," Presentation to AOBA Utility Committee, June 18, 2008.

"Understanding Your Utility Costs and Your Competitive Service Options," Presentation to the Mid-Atlantic Hispanic Chamber of Commerce, July 10, 2006.

"*Keeping Your Head Above Water In Volatile Electricity And Natural Gas Markets*," Presentation to Legum & Norman Managed Condominiums, February 28, 2006.

"*Surviving in Deregulated Energy Markets*: *What You Don't Know Will Hurt You*!" Presentation to AOBA Legislative & Regulatory Seminar, May, 18, 2006.

"*The Utility Market And Deregulation*: *What's In It For You*? Presentation to the Montgomery County, Maryland, Apartment Assistance Program, September 29, 2005.

"*Winds of Long-Term Change or Another Short-Term Market Distortion*: *Post-Katrina and Rita Energy Markets*," Keynote Presentation to AOBA Leadership Conference, September 28, 2005.

"*These Are Not Your Father's Energy Markets*," Presentation to the Institute of Real Estate Management, March 8, 2005.

"*Understanding Natural Gas Markets*," Prepared for the AOBA Alliance, Inc., August 2004.

"*Default Service: Protection or Problem*," Prepared for the AOBA Alliance, Inc., April 2004.

<u>Assessment of Winter 2000 Heating Oil Price Increases for Rhode Island</u>, Report Prepared for the Rhode Island Department of Attorney General, September 2001 (with P. Roberti).

"*Stranded Costs and Stranded Values*," Presentation before the Virginia General Assembly, Joint Subcommittee on Electric Industry Restructuring, Task Force on Stranded and Transition Costs, May, 1998.

"*Comments Regarding Restructuring of the Electric Industry in Maryland*," Presentation before the Maryland Legislative Task Force on Electric Industry Restructuring, December 1997.

Electric Industry Restructuring And Competition In Virginia, Prepared for the Apartment and Office Building Association of Metropolitan Washington, September 1997.

"*Assessment of the Proposed Pepco/BGE Merger*," Presentation to the District of Columbia Community Forum on Merger Issues, December 1996.

Assessment of the Agreement Between Delmarva Power & Light Company and the Medical Center of Delaware for the Supply of Electrical Power, Prepared for the Delaware Public Service Commission, Docket No. 94-129, December 1994.

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CERTIFICATE OF SERVICE
Formal Case No. 1180

I hereby certify on this 24th day of January 2025, that the attached Direct Testimony of Timothy Oliver and Bruce Oliver was filed electronically on behalf of the Apartment and Office Building Association and copies was electronically delivered to the service list below:

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