2021 Financial Statements and Management Discussion & Analysis

AltaGas

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) dated March 3, 2022 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 year ended December 31, 2021. This MD&A should be read in conjunction with the accompanying audited Consolidated Financial Statements and notes thereto of AltaGas as at and for the year ended December 31, 2021.

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, 2021 or the Annual Information Form for the year ended December 31, 2021.

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: potential post-acquisition contingent payments with regard to the Petrogas acquisition; upcoming director retirement; AltaGas' core strategy, including with regard to plans for dividend payments and redemption of shares; 2022 strategic priorities; expectation of 2022 annual consolidated normalized EBITDA of approximately $1.50 to $1.55 billion; anticipated 2022 normalized earnings per share of approximately $1.80 to $1.95 per share; assumed effective tax rate of approximately 21 percent in 2022; expectation that the Utilities segment will contribute approximately 55 percent of normalized EBITDA for 2022; expected growth drivers of normalized EBITDA in the Utilities segment; drivers of expected growth in the Midstream segment; expected higher normalized EBITDA from the Corporate/Other segment in 2022; estimated NGLs exposed to frac spreads prior to hedging activities; plans to manage frac exposed NGL volumes; expected invested capital expenditures of approximately $995 million in 2022; anticipated segment allocation of capital expenditures; expectation for 2022 committed capital program to be funded through internally-generated cash flow and normal course borrowings on existing committed credit facilities; the estimated cost, status and expected in-service dates for growth capital projects in the Midstream and Utilities businesses; 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; expected impact of the COVID-19 pandemic on AltaGas' business, operations and results in 2022; Washington Gas' NGQSS levels; future changes in accounting policies and adoption of new accounting standards; and AltaGas' long term strategy.

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: assumptions regarding asset sales anticipated to close in 2022, effective tax rate of approximately 21 percent, U.S./Canadian dollar exchange rates; inflation; interest rates, credit ratings, regulatory approvals and policies, expected impact of the COVID-19 pandemic; 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: risk related to COVID-19; health and safety risks; operating risks; natural gas supply risks, volume throughput, infrastructure risks; service interruptions; cyber security, information and control systems; climate-related risks, including carbon pricing; regulatory risks; litigation; changes in law; political uncertainty and civil unrest; decommissioning, abandonment and reclamation costs; reputation risk; weather data; Indigenous and treaty rights; capital market and liquidity risks; general economic conditions; internal credit risk; foreign exchange risk; risk related to the integration of Petrogas; debt financing, refinancing, and debt service risk; interest rates; counterparty and supplier risk; technical systems and processes incidents; dependence on certain partners; growth strategy risk; construction and development; transportation of petroleum products; underinsured and uninsured losses; impact of competition in AltaGas' businesses; counterparty credit risk; market 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; commitments associated with regulatory approvals for the acquisition of WGL; cost of providing retirement plan benefits; failure of service providers; and the other factors discussed under the heading "Risk Factors" in the Corporation's Annual Information Form for the year ended December 31, 2021 (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.sedar.com.

AltaGas Business Overview and Organization

AltaGas is a leading energy infrastructure company that connects natural gas and NGLs to domestic and global markets. 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 provide safe, reliable, and affordable energy to approximately 1.7 million residential and commercial customers.

This includes operating four utilities that operate across five major U.S. jurisdictions with an average 2021 rate base of approximately US$4.7 billion. This includes:

- 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;
- SEMCO Energy, which delivers essential energy to approximately 317,000 customers in Southern Michigan and Michigan's Upper Peninsula;
- ENSTAR, which is the largest gas utility in Alaska and delivers energy to more than 150,000 customers in Greater Anchorage and the surrounding Cook Inlet region; and
- Cook Inlet Natural Gas Storage Alaska (CINGSA), which is a regulated storage utility that provides reliable access to natural gas.

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 approximately 0.5 million residential, commercial, and industrial customers located in Maryland, Virginia, Delaware, Pennsylvania, Ohio, and the District of Columbia.

Midstream Segment

AltaGas' Midstream segment is a leading North American platform that connects customers and markets. From wellhead to tidewater and beyond, 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.

Throughout AltaGas' Midstream operations, the Company believes it is playing a vital role within the larger energy ecosystem that keeps the global economy moving forward and is powering the possible within our society, and doing so in a safe, reliable and affordable manner.

AltaGas' Midstream platform is heavily focused on the Montney resource play in Northeastern B.C. and centers around global exports, which is where the Company believes the market is headed for 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 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 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
- Fractionation and Liquids Handling platform, which includes 65 MBbl/d of fractionation capacity and a sizable liquids handling footprint that operates under the AltaGas and Petrogas banners.

The Midstream segment also consists of natural gas and NGL marketing business, 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, 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 578 MW of power in California and Colorado.

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. (WGL), Wrangler 1 LLC, Wrangler SPE LLC, Washington Gas Resources Corporation, 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. (SEMCO); 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, subsidiaries include AltaGas Power Holdings (U.S.) Inc., WGL Energy Systems, Inc. (WGL Energy Systems), and Blythe Energy Inc. (Blythe). SEMCO conducts its Michigan natural gas distribution business under the name SEMCO Energy Gas Company (SEMCO Gas), its Alaska natural gas distribution business under the name ENSTAR Natural Gas Company (ENSTAR) and its 65 percent interest in an Alaska regulated gas storage utility under the name Cook Inlet Natural Gas Storage Alaska LLC (CINGSA).

Fourth Quarter Highlights

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

Growth and Operational Highlights

- On December 3, 2021, AltaGas announced that its Board of Directors approved a 6 percent increase to its annual common share dividends. Concurrently, AltaGas is moving from a monthly to quarterly payment schedule with dividends expected to be paid in March, June, September and December of the 2022 calendar year at the rate of $0.265 per common share ($1.06 per common share annually). This change will be effective for the March dividend that will be paid on March 31, 2022;
- Average utilities rate base increased by approximately 8 percent to approximately US$4.7 billion in 2021, compared to approximately US$4.3 billion in 2020; and
- On October 15, 2021, AltaGas filed an application with the Canada Energy Regulator for a 25-year butane export license for 40,000 Bbl/d. The application positions AltaGas and its partners to continue to connect growing LPG production volumes from Western Canada to global markets.

Other Highlights

- On December 15, 2021, WGL completed the issuance of US$200 million of senior unsecured private placement notes with a coupon rate of 2.98 percent, maturing on December 15, 2051. The net proceeds were used to pay down existing indebtedness and for general corporate purposes; and
- As the COVID-19 pandemic persists, AltaGas continues to take proactive steps to effectively prepare for and address the evolving risks and regulatory mandates in the jurisdictions in which it operates. While the Company is moving toward reintegration of its workplaces, AltaGas' approach has been, and will continue to be, risk-based and guided by its core values. The health and safety of AltaGas' employees, customers, contractors, and the communities in which it operates is the top priority and is integrated into each aspect of AltaGas' response efforts. To date, COVID-19 has had minimal disruption to AltaGas' operations.

2021 Financial Highlights

- Normalized EBITDA was $1,490 million in 2021 compared to $1,310 million in 2020;
- Income before income taxes was $446 million in 2021 compared to $699 million in 2020;
- Cash from operations was $738 million ($2.64 per share) in 2021 compared to $773 million ($2.77 per share) in 2020;
- Normalized funds from operations were $1,198 million ($4.28 per share) in 2021 compared to $1,003 million ($3.59 per share) in 2020;
- Net income applicable to common shares was $230 million ($0.82 per share) in 2021 compared to $486 million ($1.74 per share) in 2020;
- Normalized net income was $497 million ($1.78 per share) in 2021 compared to $396 million ($1.42 per share) in 2020;
- Net debt was $8.3 billion as at December 31, 2021, compared to $8.2 billion at December 31, 2020; and
- Total long-term debt was $8.2 billion as at December 31, 2021, compared to $8.0 billion at December 31, 2020.

Highlights Subsequent to Year End

- On January 11, 2022, AltaGas closed its offering of $300 million of 5.25 percent Fixed-to-Fixed Rate Subordinated Notes, Series 1, due January 11, 2082. As a result of the offering, based on current rates, AltaGas expects cash savings of approximately $66 million over the initial ten-year term of the offering due to lower taxes and financing charges. The subordinated notes were offered under AltaGas' short form base shelf prospectus dated February 22, 2021, as supplemented by a prospectus supplement dated January 5, 2022. On February 16, 2022, AltaGas provided notice to shareholders of its intention to use the proceeds of this offering to redeem all of its issued and outstanding Series K Preferred Shares on March 31, 2022 for a redemption price equal to $25.00 per Series K Share, together with all accrued and unpaid dividends to, but excluding, the redemption date;
- In January 2022, AltaGas agreed to sell one of its customers an interest in certain Midstream processing facilities for total consideration of approximately $234 million. The transaction is expected to close in the second quarter of 2022;
- On February 9, 2022, pursuant to the terms of a Membership Interest Purchase Agreement entered into on January 14, 2022 with an undisclosed buyer, AltaGas closed the sale of a 60 MW stand-alone energy storage development project in Goleta, California for total proceeds of approximately US$15 million, subject to certain contingencies; and
- On February 11, 2022, AltaGas entered into a stock purchase agreement to sell a 70MW combined cycle power plant in Brush, Colorado. The transaction is expected to close in the second quarter of 2022.

2022 Outlook

In 2022, AltaGas expects to achieve annual consolidated normalized EBITDA of approximately $1.50 to $1.55 billion, compared to actual normalized EBITDA of $1.49 billion in 2021, and normalized earnings per share of approximately $1.80 to $1.95 per share compared to actual normalized earnings per share and net income per share of $1.78 per share and $0.82 per share, respectively in 2021, assuming an effective tax rate of approximately 21 percent. For the year ended December 31, 2021, income before income taxes and net income applicable to common shares were $446 million and $230 million, respectively.

The Utilities segment is expected to contribute approximately 55 percent of normalized EBITDA, with growth driven primarily by revenue growth from rate cases settled in 2021, increased spend on accelerated capital programs, ongoing operational cost optimization activities, modest customer growth, and the expected discontinuation of COVID-19 related moratoriums in 2022. Expected growth in the Midstream segment is primarily driven by the continued volume growth of AltaGas' key assets through optimization initiatives at LPG export terminals and a favorable NGL and frac commodity price environment together with AltaGas' commodity hedging programs. Midstream segment earnings are approximately 65 percent underpinned through take-or-pay, cost-of-service, and fee-for-service contracts at the Midstream facilities and tolling agreements at the export facilities together with hedged NGL and frac margins. Normalized EBITDA from the Corporate/Other segment, which includes AltaGas' remaining power assets, is expected to be higher in 2022 mainly due to lower expected expenses related to employee incentive plans. Overall growth is expected to offset lost normalized EBITDA from a full year impact of asset sales completed in 2021 and the impact of expected 2022 asset sales.

The forecasted normalized EBITDA and earnings per share include assumptions around the U.S./Canadian 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. Please refer to the *Risk Management* section of this MD&A for further discussions of the risks to AltaGas arising from the COVID-19 pandemic.

At RIPET and Ferndale, NGL price margins are protected through AltaGas' comprehensive hedging programs. AltaGas is well hedged for 2022 with approximately 74 percent of its 2022 expected frac exposed volumes hedged at approximately $33/Bbl, prior to transportation costs. In addition, approximately 44 percent of AltaGas' 2022 expected export volumes are either tolled or financially hedged with an average FEI to North American financial hedge price of approximately US$13/Bbl for non-tolled propane and butane volumes. AltaGas plans to manage the export facilities such that a growing portion of annual capacity will be underpinned by tolling arrangements, and expects to reach this objective over the next several years.

2022 Midstream Hedge Program	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Full Year 2022
Global Exports volumes hedged (%) (1)	79	44	31	22	44
Average propane/butane FEI to North America average hedge (US$/Bbl) (2)	15.29	10.56	10.43	9.76	13.17
Fractionation volume hedged (%) (3)	71	79	75	68	74
Frac spread hedge rate (CAD$/Bbl) (3)	24.40	36.02	36.14	36.17	33.08

(1) Approximate expected volume hedged. Includes contracted tolling volumes and financial hedges. Based on assumption of average exports of 90 MBbls/d.
(2) Approximate average for the period. 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, and weather. The following table illustrates the approximate effect of these key variables on AltaGas' expected normalized EBITDA for 2022:

Factor	Increase or decrease	Approximate impact on normalized annual EBITDA *($ millions)*
Degree day variance from normal - Utilities (1)	5 percent	9
Change in Canadian dollar per U.S. dollar exchange rate	0.05	45
Propane Far East Index to Mont Belvieu spread (2)	US$1/Bbl	22
Pension discount rate	1 percent	26

(1) Degree days – Utilities relate to SEMCO Gas, ENSTAR, and District of Columbia 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 Gas, during the prior 10 years for ENSTAR, and during the prior 30 years for Washington Gas.
(2) The sensitivity is net of hedges currently in place. The impact on EBITDA due to changes in the spread will vary and is being managed through an active hedging program.

Growth Capital

Based on projects currently under review, development, or construction, AltaGas expects invested capital expenditures of approximately $995 million in 2022 compared to $798 million in 2021. Actual 2021 invested capital was lower than previous guidance of $850 million primarily due to the impact of foreign exchange rates and lower Midstream spending on growth projects and deferral of certain discretionary Midstream maintenance capital to 2022. The majority of 2022 capital expenditures are expected to focus on projects within the Utilities platform that are anticipated to deliver stable and transparent rate base growth, positive risk-adjusted returns, and safe, reliable service for customers. The Utilities segment is expected to account for approximately 75 to 80 percent of total capital expenditures, while the Midstream segment is expected to account for approximately 20 percent and the Corporate/Other segment is expected to account for any remainder. In 2022, AltaGas' capital expenditures for the Utilities segment will focus primarily on accelerated pipe replacement programs, customer growth, and system betterment. In the Midstream segment, capital expenditures are anticipated to primarily relate to facility turnarounds, maintenance and administrative capital, optimization of existing assets, investment in Environment, Social & Governance (ESG) initiatives, and new business development. Maintenance capital related to Midstream assets and remaining power assets in the Corporate/Other segment is expected to be approximately $90 to $100 million of the total capital expenditures in 2022. The Corporation continues to focus on capital efficient organic growth and disciplined capital allocation while improving balance sheet strength and flexibility.

AltaGas' 2022 committed capital program is expected to be funded through internally-generated cash flow and normal course borrowings on existing committed credit facilities.

Please refer to the *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)]	Expenditures to Date [(2)]	Status	Expected In-Service Date
Midstream Projects					
Nig Creek Expansion	50%	$58 million	$37 million	The Nig Creek facility was expanded in two phases. Phase one expanded designed capacity by 55 Mmcf/d gross (27.5 Mmcf/d net) by adding inlet compression, sales compression, and other plant equipment. Construction and commissioning of Phase I was completed in early July 2021. The second phase increased capacity by an additional 25 Mmcf/d gross (12.5 Mmcf/d net) and included a deep cut plant for additional liquids recoveries. Construction and commissioning of Phase II was completed in the fourth quarter of 2021 and is now on-stream.	Phase I was in-service early Q3 and Phase II was in-service Q4 2021.
Mountain Valley Pipeline (MVP)	10%	US$352 million	US$352 million	On January 25, 2022, the Fourth Circuit Court of Appeals vacated U.S. Forest Service and Bureau of Land Management permits that allow the pipeline to pass through 3.5 miles of the Jefferson National Forest. On February 2, 2022, the Fourth Circuit Court also issued a decision vacating MVP's U.S. Fish and Wildlife Service Endangered Species Act Biological Opinion (Biological Opinion), remanding it on specific issues. Until the pipeline has a valid Biological Opinion, the Army Corps has stated they will not approve the necessary permits. MVP continues to review these decisions and evaluate the possible paths forward, which include working with the relevant federal agencies and the considerations of potential legal appeals. As of December 31, 2021, approximately 94 percent of the project is complete, which includes construction of all original interconnects and compressor stations. AltaGas' exposure is contractually capped to the original estimated contributions of approximately US$352 million. In the fourth quarter of 2021, AltaGas impaired its equity investment in MVP to a carrying value of US$352 million as a result of these ongoing legal and regulatory challenges. See Note 14 of the 2021 Annual Consolidated Financial Statements for additional details.	Completion date under review
MVP Southgate Project	5%	US$20 million	US$4 million	Due to the evolving regulatory and legal environment for pipeline construction and ongoing challenges related to MVP and the MVP Southgate project, MVP is evaluating the MVP Southgate project, including engaging in discussions with the shipper regarding options for the project, including potential changes to the project design and timing in lieu of pursuing the project as originally contemplated. 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 these ongoing legal and regulatory challenges. See Note 14 of the 2021 Annual Consolidated Financial Statements for additional details.	Completion date under review

Project	AltaGas' Ownership Interest	Estimated Cost (1)	Expenditures to Date (2)	Status	Expected In-Service Date
Utilities Projects					
Accelerated Utility Pipe Replacement Programs – ***District of Columbia***	100%	Estimated US$150 million over the three year period from January 2021 to December 2023, plus additional expenditures in subsequent periods.	US$33 million (3)	The second phase of the accelerated utility pipe replacement programs in the District of Columbia (PROJECT*pipes* 2) began in January 2021.	Individual assets are placed into service throughout the program.
Accelerated Utility Pipe Replacement Programs – ***Maryland***	100%	Estimated US$350 million over the five year period from January 2019 to December 2023, plus additional expenditures in subsequent periods.	US$207 million (3)	The second phase of the accelerated utility pipe replacement programs in Maryland (STRIDE 2.0) began in January 2019. On March 2, 2022, the PSC of MD issued an Order reducing the calendar year 2022 STRIDE surcharge by 14.7 percent for the remainder of the year. The Order noted that Washington Gas filed its revised surcharge in compliance with the Order on February 11, 2021. Recovery of STRIDE expenditures not included in this surcharge will be requested through the normal rate-making process.	Individual assets are placed into service throughout the program.
Accelerated Utility Pipe Replacement Programs – ***Virginia***	100%	Estimated US$500 million over the five year period from January 2018 to December 2022, plus additional expenditures in subsequent periods.	US$402 million (3)	The second phase of the accelerated pipe replacement programs in Virginia (SAVE 2.0) began in January 2018. On December 1, 2021, Washington Gas filed its proposed amendment for the 2023 to 2027 SAVE Plan, proposing to invest approximately US$889 million from 2023 to 2027 to replace higher risk pipeline and facilities in Virginia. A decision from the Commonwealth of Virginia State Corporation Commission (SCC of VA) is expected around May 30, 2022.	Individual assets are placed into service throughout the program.
Accelerated Replacement Programs – ***Michigan***	100%	Estimated US$115 million over five year period from 2021 to 2025.	US$21 million (3)	A new Main Replacement Program (MRP) was agreed to in SEMCO's last rate case settled in December 2019. The new five-year MRP program began in 2021 with a total spend of approximately US$60 million. In addition to the new MRP program, SEMCO was also granted a new Infrastructure Reliability Improvement Program (IRIP) which is also a five-year program with a total spend of approximately US$55 million beginning in 2021.	Individual assets are placed into service throughout the program.

(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) Expenditures to date reflect total cumulative expenditures incurred from inception of the projects to December 31, 2021. For WGL projects, this also includes any expenditures prior to the close of the WGL Acquisition on July 6, 2018.

(3) 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. Expenditures to date only include amounts for the current programs described above, and exclude any expenditures made under prior increments of the programs. Actual regulatory filings may differ from reported amounts.

Utilities

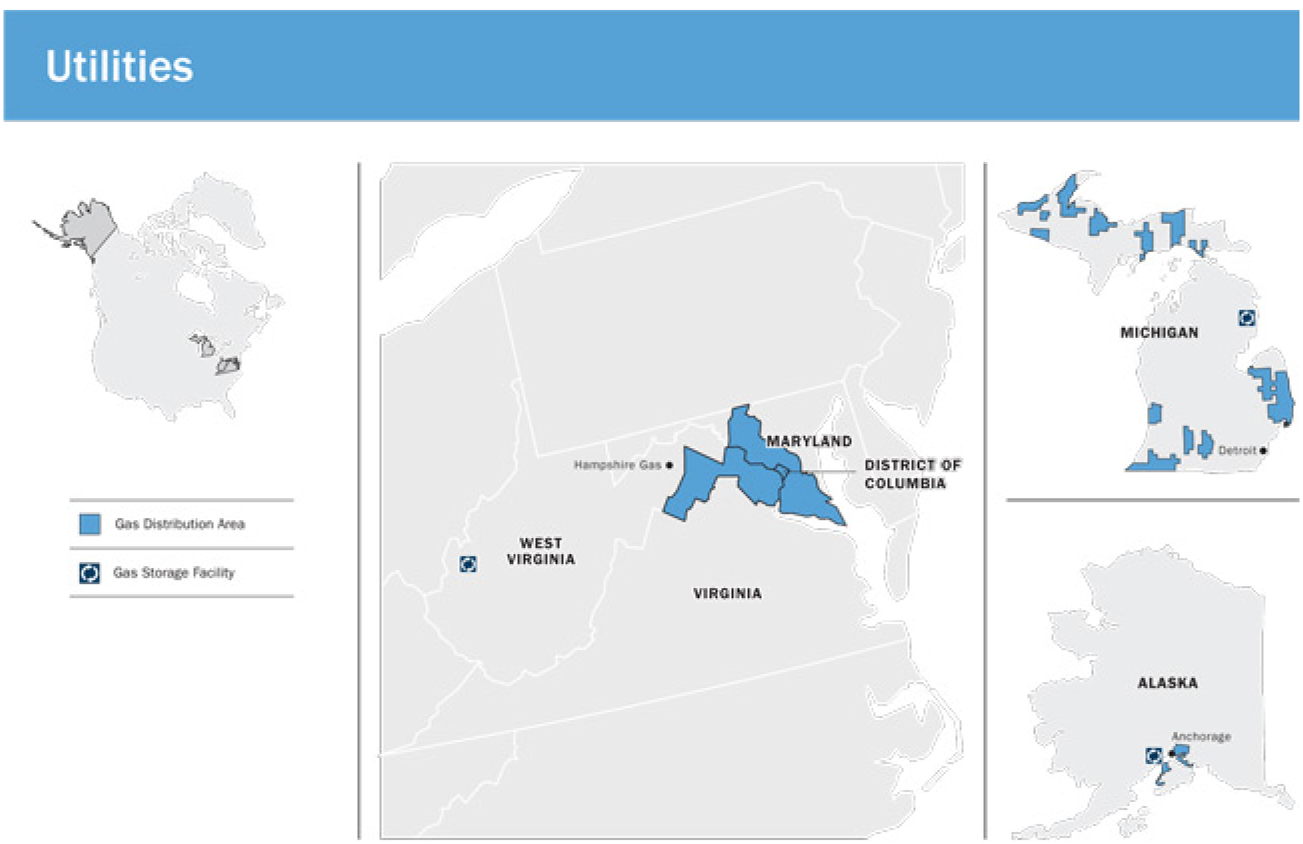
Description of Assets

AltaGas owns and operates utility assets that store and deliver natural gas to end-users in Virginia, Maryland, Michigan, the District of Columbia, and Alaska, serving approximately 1.7 million customers and with a combined average 2021 rate base of approximately US$4.7 billion.

The utilities are underpinned by regulated returns and regulatory regimes that generally provide stable earnings and cash flows. The Utilities segment enhances the diversification of AltaGas' portfolio of energy infrastructure assets and strengthens the Corporation’s business profile, thus allowing the Corporation to meet its objective of operating a diversified low-risk, high-growth energy infrastructure business that is focused on delivering resilient and durable value for its stakeholders with long-life assets.

The Utilities segment includes:

- Washington Gas in Virginia, Maryland, and the District of Columbia;
- Hampshire, providing regulated interstate natural gas storage to Washington Gas;
- SEMCO Gas in Michigan;
- ENSTAR in Alaska;
- A 65 percent interest in Cook Inlet Natural Gas Storage Alaska LLC (CINGSA) in Alaska; and
- WGL's Retail Marketing business, which sells power and natural gas directly to residential, commercial, and industrial customers in Maryland, Virginia, Delaware, Pennsylvania, Ohio, and the District of Columbia.



All of AltaGas' regulated Utilities are allowed the opportunity to earn regulated returns. This return on rate base is composed of regulator-allowed financing costs and return on equity (ROE). If actual costs are different from those recoverable through approved rates, the utility bears the risk of this difference other than for certain costs that are subject to deferral treatment.

Earnings in the Utilities segment are seasonal, as revenues are primarily based on the demand for space heating in the winter months, mainly from November to March. Costs, on the other hand, are generally incurred more uniformly over the year. This typically results in stronger first and fourth quarters and weaker second and third quarters. In Michigan, Alaska, and the District of Columbia, earnings can be impacted by variations from normal weather resulting in delivered gas volumes being different than anticipated. Increases in the number of customers or changes in customer usage are other factors that might typically affect delivered volumes, and hence actual earned returns for the Utilities segment. In Virginia and Maryland, Washington Gas has billing mechanisms in place which are designed to eliminate or mitigate the effects of variance in customer usage caused by weather and other factors such as conservation.

Washington Gas

Washington Gas is a regulated public utility that has been engaged in the natural gas distribution business since 1848, and provides regulated gas distribution services to end users in Virginia, Maryland, and the District of Columbia. At the end of 2021, Washington Gas had approximately 1.2 million customers, of which approximately 94 percent were residential. The number of customers at Washington Gas increased approximately 1 percent in 2021. The average rate base for the year ended December 31, 2021 was approximately US$3.5 billion. At the end of 2021, the approved regulated ROE for Washington Gas in its various jurisdictions ranged from 9.2 - 9.7 percent based on an equity ratio ranging from 52.1 - 53.5 percent.

Washington Gas is regulated by the PSC of DC, the PSC of MD, and the SCC of VA, which approve its terms of service and the billing rates that it charges to customers. The rates charged to Utilities customers are designed to recover Washington Gas' operating expenses and natural gas commodity costs and to provide a return on its investment in the net assets used in its firm gas sales and delivery service.

Washington Gas has accelerated pipe replacement programs in place in each of its three jurisdictions. Washington Gas accelerates pipe replacement in order to reduce risk and further enhance the safety and reliability of the pipeline system. Each regulatory commission having jurisdiction over Washington Gas' retail rates has approved accelerated replacement programs with an associated surcharge mechanism to recover the cost, including a return, on those capital investments. In contrast to the traditional rate-making approach to capital investments, for the accelerated pipe replacement programs, Washington Gas is receiving recovery for these investments through the approved surcharges for each program and is authorized to invest in each of these programs over a three- to five-year period.

Washington Gas' customers are eligible to purchase their natural gas from unregulated third-party marketers through natural gas unbundling. As at December 31, 2021, approximately 15 percent of its customers have chosen to purchase gas from marketers. This does not negatively impact Washington Gas' net income as the Corporation does not earn a margin on the sale of natural gas to firm customers, but only from the delivery and distribution of the gas.

Washington Gas obtains natural gas supplies that originate from multiple regions throughout the United States. At December 31, 2021, it had service agreements with four pipeline companies that provided firm transportation and storage services with contract expiration dates ranging from 2022 to 2044. Washington Gas has also contracted with various interstate pipeline and storage companies to add to its storage and transportation capacity. Washington Gas, under its asset optimization program, makes use of storage and transportation capacity resources when those assets are not required to serve utility customers. The objective of this program is to derive a profit to be shared with its utility customers. These profits are earned by entering into commodity-related physical and financial contracts with third parties.

Hampshire

Hampshire owns underground natural gas storage facilities, including pipeline delivery facilities located in and around Hampshire County, West Virginia, and operates these facilities to serve Washington Gas. Hampshire is regulated by the FERC. Washington Gas purchases all of the storage services of Hampshire, and includes the cost of the services in the commodity cost of its regulated energy bills to customers. Hampshire operates under a “pass-through” cost-of-service based tariff approved by FERC.

SEMCO Gas

SEMCO owns and operates a regulated natural gas distribution utility in Michigan operating under the name SEMCO Gas and has an interest in a regulated natural gas storage facility in Michigan. At the end of 2021, SEMCO Gas had approximately 317,000 customers. Of these customers, approximately 92 percent were residential. In 2021, SEMCO Gas experienced customer growth of approximately 1 percent reflecting growth in the franchise areas and customer conversions with the favorable price of natural gas compared to other heating sources. The average 2021 rate base was approximately US$770 million. In 2021, the approved regulated ROE for SEMCO Gas was 9.87 percent with an approved capital structure based on 45.86 percent equity.

SEMCO Gas is regulated by the MPSC. It operates under cost-of-service regulation and utilizes actual results from the most recently completed fiscal year along with known and measurable changes in its application for new rates.

SEMCO Gas has an Accelerated MRP surcharge to recover a stated amount of accelerated main replacement capital expenditures in excess of what is authorized in its current base rates. For the years 2021 to 2025, the anticipated annual average capital spending is approximately US$12 million. Any MRP revenue associated with unspent capital will be placed into a regulatory liability account to be addressed in the next general rate base case. Additionally, a new IRIP was approved in the 2019 rate case, pursuant to which SEMCO Gas will complete certain projects totaling US$55 million to improve the reliability of infrastructure. Customers were billed a surcharge beginning in 2021 for the IRIP.

ENSTAR and CINGSA

SEMCO owns and operates a regulated natural gas distribution utility in Alaska under the name ENSTAR. SEMCO, through a subsidiary, holds a 65 percent interest in CINGSA, a regulated natural gas storage utility in Alaska. At the end of 2021, ENSTAR had approximately 150,000 customers including residential, commercial, and transportation, and of these customers, approximately 91 percent were residential. In 2021, ENSTAR experienced customer growth of approximately 1 percent reflecting growth in the franchise areas and customer conversions with the favorable price of natural gas compared to other heating sources. The average 2021 rate base was approximately US$279 million for ENSTAR and US$65 million for CINGSA (SEMCO's 65 percent share).

ENSTAR and CINGSA are regulated by the Regulatory Commission of Alaska (RCA) and operate under cost-of-service regulation utilizing actual results from the most recently completed fiscal year along with known and measurable changes in their application for new rates.

Retail Energy Marketing

The U.S. retail gas marketing business sells natural gas directly to residential, commercial, and industrial customers in Maryland, Virginia, Delaware, Pennsylvania, and the District of Columbia.

The U.S. retail power marketing business sells power to end users in Maryland, Delaware, Pennsylvania, Ohio, and the District of Columbia. This area is served by the PJM Interconnection (PJM), a regional transmission organization that regulates and coordinates generation supply and the wholesale delivery of electricity in these states and jurisdictions.

Natural gas and electricity are purchased with the objective of earning a profit through competitively priced sales contracts with end users. Requirements to serve retail customers is closely matched with commitments for deliveries, and thus, a secured supply arrangement expiring in March 2024 has been entered into with Shell Energy North America (US), L.P, which reduces credit requirements.

Capitalize on Opportunities

While providing safe and reliable service, AltaGas pursues opportunities in the Utilities segment to deliver value to its customers while enhancing long-term shareholder returns. The Corporation's objectives are to:

- Ensure safe, reliable operations and infrastructure, providing effective and cost-efficient service for customers;
- Upgrade the Utilities platform to enhance the customer value proposition, drive better stakeholder outcomes and deliver improved environmental benefits;
- Enhance returns and capital efficiency and more timely recovery of expenditures through rate cases and increased utilization of accelerated rate recovery programs;
- Enhance and grow the business through asset optimization, cost reduction initiatives, and operational efficiencies to reduce costs and deliver an improved customer experience;
- Improve business processes and drive down leak remediation costs, reinvesting savings into improving the customer experience;
- Provide better stakeholder outcomes and environmental benefits by focusing on accelerated pipelines replacement and network upgrades which provides optionality for blending of additional cleaner burning fuels;
- Invest in opportunities that reflect the emerging lower carbon ecosystem and shifts in the market;
- Attract and retain customers through exceptional customer service;
- Continue to grow the consolidated Utilities rate base;
- Maintain strong relationships with local communities, Indigenous peoples, governments, and regulatory bodies; and
- Maintain strong community and regulatory relationships while ensuring appropriate returns to shareholders.

AltaGas expects to grow its existing utility infrastructure through continued investment and capital improvements in franchise areas, which will result in rate base growth and continued customer growth including the conversion of users of alternative energy sources to natural gas. AltaGas' utilities have had annual rate base growth averaging approximately 7 percent over the past three years after adjusting for the impact of foreign exchange translation. The growth in rate base is a result of prudent investments in current areas of operations, and the addition of new customers. Customer growth rates for AltaGas' utilities are moderate, as is typical with mature utilities, with growth rates generally tied closely to the economic growth of the respective franchise regions.

Midstream

Description of Assets

AltaGas' Midstream segment is a leading North American platform that connects customers and markets. From wellhead to tidewater and beyond, 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 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.

AltaGas' Midstream platform is heavily focused on the Montney resource play in Northeastern B.C. and centers around global exports, which is where the Company believes the market is headed for 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.

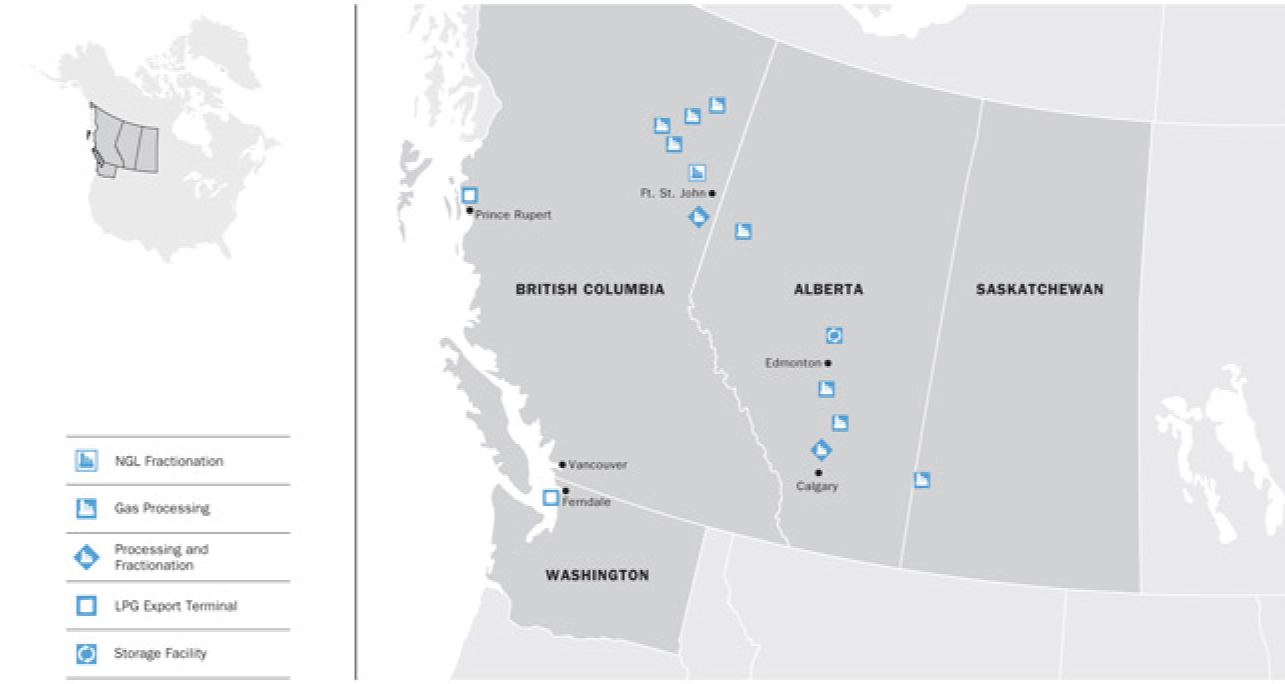
There are three core pillars to AltaGas' Midstream platform that are integral to each other and facilitate the Company's wellhead to tidewater and beyond value chain. These include:

- Global Exports, which includes AltaGas' two 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 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
- Fractionation and Liquids Handling platform, which includes 65 MBbl/d of fractionation capacity and a sizable liquids handling footprint that operates under the AltaGas and Petrogas banners.

The Midstream segment also consists of natural gas and NGL marketing business, domestic logistics, trucking and rail terminals, and approximately 3.2 million barrels of liquid storage capability though a network of underground salt caverns through the Company's Strathcona Storage JV with ATCO Energy Solutions Ltd, as well as AltaGas' 10 percent interest in the Mountain Valley Pipeline.

The Midstream segment includes expansion projects under development or construction, as discussed under the *Growth Capital* section of this MD&A.

Midstream



<u>Global Exports</u>

AltaGas’ global export assets include the Company's RIPET and Ferndale export terminals, which are located in Northern B.C. and Washington State, respectively. These terminals facilitate North American producers and aggregators to access global markets and provides incremental opportunities for improved price realization for propane and butane production. Between the two facilities, AltaGas has the ability to ship in excess of 150,000 Bbl/d.

RIPET commenced commercial operations on May 23, 2019, with the first propane shipment departing from the terminal to Asia. RIPET has storage of 600,000 Bbls and throughput capacity of up to 80,000 Bbls/d at the terminal. As AltaGas builds on the Company's operational capabilities and continues to align with leading North American producers and global customers in Asia through long-term tolling agreements, it expects to continue to increase throughput from RIPET. On August 21, 2020, AltaGas was granted an additional 25-year license to export an additional 46,000 bbl/d of propane to North American and global markets, bringing its aggregate propane export capacity under 25-year export licenses to 92,000 Bbls/d. For 2022, AltaGas has in place agreements for the purchase of approximately 75 percent of the propane expected to be shipped from RIPET. The RIPET dock offers deep draft, sufficient to accommodate loading VLGCs.

AltaGas also operates the Ferndale LPG terminal, which is capable of loading VLGCs, has 800,000 Bbls of on-site storage, and currently can flow approximately 75,000 Bbls/d. Located approximately 100 miles north of Seattle, the terminal is also pipeline connected to two regional refineries, providing additional supply, sales, and fee-for-service opportunities for the facility. For 2022, AltaGas has in place agreements for propane and butane offtake volumes, for the purchase of approximately 76 percent of the product expected to be shipped from Ferndale.

On October 15, 2021, AltaGas filed an application with the Canada Energy Regulator for a 25-year butane export license for 40,000 Bbl/d. The application positions AltaGas and its partners to continue to connect growing LPG production volumes from

Western Canada to global markets. The RIPET and Ferndale export terminals represent strategic outlet points for North American LPG volumes as they are competitively situated to serve the high-demand Far East market with shorter average shipping times and competitive arbs as compared to the U.S. Gulf Coast or Arabian Gulf.

Terminal demand is supported through various long-term purchase agreements with Canadian and U.S. suppliers, primarily from key Northern British Columbia and Alberta gathering facilities and select U.S. producing regions, including the Bakken in North Dakota. Petrogas also maintains service agreements with numerous Tier 1 rail providers in order to leverage existing rail networks and secure competitively priced LPGs across North America.

Gas Processing

Gas processing activities are comprised of gathering systems that move raw natural gas and NGLs from producing wells to processing facilities, where impurities and certain hydrocarbon components are removed, and the product moves down the energy value chain. The gas is then compressed to meet downstream pipelines' operating specifications for transportation to North American natural gas markets. All of AltaGas' processing facilities are capable of extracting NGLs and converting the throughput into usable products. The facilities provide revenues based on take-or-pay contracts and fee-for-service arrangements with its customers, with the latter based on volumes processed. A significant portion of AltaGas' Midstream contracts flow the Company's operating costs through to the producers. AltaGas' processing infrastructure includes:

- The Townsend facility, a 550 Mmcf/d gas processing facility, along with the related egress pipelines, truck terminal, and NGL treatment infrastructure (the Townsend complex), which is wholly owned and operated by AltaGas. The majority of the processing capacity is contracted with Montney producers in the area under long-term take-or-pay agreements. In the second quarter of 2020, Townsend 2B and a gas gathering pipeline that connects upstream fields to AltaGas facilities were commissioned, which added 198 Mmcf/d C3+ deep cut gas processing capacity at the Townsend Complex;
- The Gordondale facility, which has licensed capacity of 150 Mmcf/d of natural gas and is wholly owned and operated by AltaGas. The Gordondale facility processes gas gathered from Birchcliff Energy Ltd.'s Gordondale Montney development under a long-term take-or-pay contract. The plant is equipped with liquids extraction facilities to capture the NGL value for the producer;
- The Blair Creek facility, which has licensed capacity of 120 Mmcf/d of natural gas and is wholly owned and operated by AltaGas. The facility processes gas gathered from producers in the area. The plant is equipped with liquids extraction facilities to capture the NGL value for the producer;
- The Aitken Creek processing facilities, in which AltaGas has a 50 percent ownership interest. These facilities include Aitken Creek North, an operating shallow gas plant with a current capacity of 110 Mmcf/d (55 Mmcf/d net), and Nig Creek, a deep cut gas plant with a current capacity of 180 Mmcf/d (90 Mmcf/d net). Phase 1 of Nig Creek GP2B increased inlet capacity by 55 Mmcf/d (28 Mmcf/d net) by adding inlet compression, sales compression, and other plant equipment. Phase 1 of Nig Creek GP2B was completed early in the third quarter of 2021 and is now on stream. The second phase increased capacity by an additional 25 Mmcf/d gross (12.5 Mmcf/d net) and includes a deep cut plant for additional liquids recoveries. Phase 2 was completed at the end of the fourth quarter of 2021. The Aitken processing facilities are located in the liquids-rich Montney resource play in NEBC and are operated by Tourmaline. AltaGas and Tourmaline have long-term processing, transportation, and marketing agreements that include AltaGas liquids handling infrastructure in NEBC;
- The Harmattan facility, which has a natural gas processing capacity of 490 Mmcf/d and is wholly owned and operated by AltaGas. Harmattan's natural gas processing consists of sour gas treating, co-stream straddle processing, and NGL extraction. In addition, Harmattan has fractionation and terminalling facilities (see *Fractionation and Logistics* section below); and
- Interests in four NGL extraction plants with net licensed inlet capacity of 1.0 Bcf/d. The extraction plants consist of Edmonton Ethane Extraction Plant (EEEP), Joffre Ethane Extraction Plant (JEEP), Pembina Empress Extraction

Plant (PEEP), and the Younger extraction plant (Younger). The extraction assets provide stable fixed-fee or cost-of-service type revenues and margin based revenues. The natural gas supply to EEEP, JEEP, and PEEP depends on natural gas demand pull from residential, commercial and industrial usage inside and outside of Western Canada, and gas liquids demand pull from the Alberta petrochemical market and propane heating. Natural gas supply to Younger is dependent on the amount of raw natural gas processed at the McMahon gas plant, which is based on the robust natural gas producing region of NEBC.

Fractionation and Logistics

Fractionation production is a function of NGL mix volumes processed, liquids composition, recovery efficiency of the plants, and plant on-line time. Due to the integration and inter-connectivity of AltaGas' Midstream assets, the fractionation and logistics activities provide integral services to the other Midstream businesses and customers by providing access to high value NGL products with access to North American and global markets through rail networks, pipelines, RIPET, and Ferndale.

AltaGas' logistics infrastructure consists of NGL pipelines, treating, storage, truck, and rail terminal infrastructure centered around AltaGas' key Midstream operating assets at RIPET, Harmattan and, in NEBC, Townsend and North Pine. AltaGas' fractionation and logistics business also includes Petrogas' terminals, wellsite fluids and fuels, and trucking and liquids handling.

AltaGas' fractionation and logistics infrastructure includes:

- The North Pine facility, which is the only custom fractionation plant in British Columbia, providing area producers with a lower cost, higher netback alternative for their NGLs than transporting and fractionating in Edmonton, Alberta. The first train of the North Pine facility is capable of processing up to 10,000 Bbls/d of NGL mix. The second train, commissioned in the first quarter of 2020, provides an additional 10,000 Bbls/d of NGL mix. The North Pine facility is connected to the Townsend truck terminal via the North Pine pipelines, to the Tourmaline Gundy facility, and also has access to the Canadian National (CN) rail network, allowing the transportation of propane, butane, and condensate to North American markets and propane to global markets via RIPET and butane via Ferndale;
- The Harmattan gas processing complex, which has NGL fractionation capacity of 35,000 Bbls/d, a 450 Bbls/d capacity frac oil processing facility, and a 200 tonnes/d capacity industrial grade carbon dioxide (CO_2) facility. Harmattan is the only deep-cut and full fractionation plant in its operating area;
- Younger, which has fractionation capacity of 19,500 Bbls/d (9,750 Bbls/d net) and is operated by Pembina. AltaGas has a 50 percent interest in Younger's fractionation, storage, loading, treating, and terminalling of NGL and the remaining interest is held by Pembina;
- A network of NGL pipelines in the NEBC area that connects upstream gas plant producers to the AltaGas North Pine facility. The NEBC NGL pipelines consist of three liquids egress lines. The third line, which connects the Townsend facility to the Townsend truck terminal on the Alaska Highway (30 km) and AltaGas' North Pine facility (70 km), was commissioned in the third quarter of 2020;
- NGL and spec propane lines that connect the Townsend complex in the North, to the Aitken Creek facilities through a 60 km NGL pipeline (Aitken Connector), Canadian Natural Resources Limited's Nig plant through a lateral, and to the Tourmaline Gundy facility in the West, through a 15 km spec propane line were all commissioned in the first half of 2020;
- A rail logistics network consisting of approximately 4,600 rail cars that AltaGas manages to support LPG and NGL handling, including approximately 3,000 rail cars from Petrogas;
- Petrogas' terminals and storage business, which provides support to the LPG exports and distribution business by providing the ability to source, transport, process, store, and deliver products through strategically located fixed assets throughout North America. In addition, the terminals business provides various storage and handling services to third-party customers through take-or-pay and fee-for-service agreements, which provide earnings stability through

volatile commodity price environments. The terminals business consists of strategically located crude and NGL assets which provide storage, blending, rail, and truck logistical support and waterborne LPG export capabilities. Petrogas' terminal business includes Griffith LPG Terminal, which is capable of handling approximately 12,000 Bbls/d of NGLs, 700,000 barrels of underground cavern storage and up to 220 railcars rail siding capacity; the Strathcona Storage JV, which consists of four underground storage salt caverns in service that have a combined storage capacity of approximately 2,516,000 Bbls and a fifth cavern under development that is expected to be placed in service in the first half of 2022; and Sarnia Storage and Crude Oil Terminal JV agreement, which provides up to 2.1 million barrels of crude oil and refined product storage capacity with outbound throughput supported by 10,000 Bbls/d of rail loading capacity. The right to access the terminal assets under the joint venture arrangement have been recorded as a lease by Petrogas;

- 50 percent ownership of the 6.4 Bcf Sarnia natural gas storage facility, which is connected to the Dawn Hub in Eastern Canada;
- Three primary trucking entities which Petrogas operates, providing transportation related services within the WCSB and the Pacific Northwest in the U.S. by hauling frac fluid, produced water, crude oil, and NGLs between producers, terminals, customers and end users; and
- Enerchem International Inc., a wholly owned subsidiary of Petrogas, is a Canadian corporation which focuses on the production of drilling and wellsite fluids and consumer fuels. Through the fractionation of crude oil feedstock, Enerchem produces and distributes proprietary hydrocarbon fluids for fracturing and drilling of oil and gas wells to improve productivity and to resolve oilfield production challenges for downstream producers. Enerchem operates two primary facilities located in Sundre and Slave Lake, Alberta, which are capable of processing over 1.5 million barrels of finished products per year. These plants are supported by various ancillary storage and distribution facilities located across the WCSB, providing over 150,000 barrels of storage capacity, strategically placed within the vicinity of active drilling regions.

Energy Services

In addition to supporting the other Midstream activities within AltaGas, the logistics business identifies opportunities to buy and resell NGLs for producers, and exchange, reallocate or resell pipeline and storage capacity to earn a profit. Net revenues from these activities are derived from low risk opportunities based on transportation cost differentials between pipeline systems and differences in commodity prices from one period to another. Margins are earned by locking in buy and sell transactions in compliance with AltaGas’ credit and commodity risk policies. AltaGas also provides energy procurement services for utilities gas users and manages the third-party pipeline transportation requirements for many of its gas marketing customers. In the second quarter of 2021, AltaGas completed the sale of the majority of WGL Midstream's commodity business. Refer to Note 4 of the 2021 Annual Consolidated Financial Statements for additional details.

Petrogas' marketing business is focused on the purchase, sale, exchange, and distribution of NGLs and crude oil, primarily in proximity to its strategically owned and leased asset base. By leveraging Petrogas' fully integrated infrastructure base and extensive logistical capabilities, the marketing team is able to source competitively priced supply at the key hubs and across various hydrocarbon basins in order to capture arbitrage opportunities derived through regional pricing differentials. Marketing efforts are driven by two primary focuses: 1) domestic NGL and crude oil wholesale, and 2) LPG waterborne exports. Additionally, this business provides operational support to the Ferndale export terminal by providing product supply and export sales agreement negotiation services. Petrogas supports its distribution efforts by maintaining an extensive leased rail fleet. Leases are established on a staggered maturity schedule with multiple lessors, to ensure railcar integrity and up-to-date DOT classification and all leases are on a full-service basis.

Pipeline Investments

AltaGas has a 10 percent equity interest in the MVP. The proposed pipeline is planned to transport approximately 2.0 Bcf/d of natural gas. In April 2018, AltaGas entered into a separate agreement to acquire a 5 percent equity interest in a lateral project to build an interstate natural gas pipeline (MVP Southgate) which would receive natural gas from MVP. Due to ongoing legal and regulatory challenges the in-service dates of MVP and MVP Southgate are being reassessed.

Capitalize on Opportunities

To take advantage of opportunities, including the continued Montney LPG growth and the increasing Asian demand for LPG, AltaGas plans to grow its Midstream business by expanding and optimizing strategically-located assets as well as its global export platform. New infrastructure consists of larger scale facilities supporting the vast reserves in North America and growing the footprint and integration of AltaGas' existing assets. While providing safe and reliable service, AltaGas pursues opportunities in the Midstream segment to deliver value to its customers while enhancing long-term shareholder value. The Corporation's objectives are to:

- Maximize and grow the unique structural advantage within AltaGas' integrated platform in the Montney region, leveraging RIPET/Ferndale and the integrated value chain to attract volumes;
- Increase utilization and export volumes, optimize commercial and operational capability at RIPET and Ferndale, and continue to build on export competency while positioning the platform to export additional clean burning fuels;
- Provide a fully-integrated Midstream service offering including gas processing and NGL extraction, fractionation, liquids handling facilities, and transportation and marketing services to customers across the energy value chain, with higher producer netbacks resulting from global export access to higher value global markets, including Asia;
- Advance emissions intensity reduction plans and targets;
- Advance alternative fuels opportunities and new growth initiatives that are within AltaGas' core markets and competencies;
- Maintain strong relationships with Indigenous peoples, regulators, customers, partners, and service providers;
- Optimize existing rail infrastructure to gain scale and efficiencies;
- Increase utilization and throughput at existing facilities while maintaining top tier operating costs, high reliability and NGL recovery, highly efficient business administration, and effective safety and environmental programs;
- Mitigate commodity risk through tolling agreements and effective hedging and risk management programs;
- Mitigate volume risk through contractual structures, redeployment of equipment, and expansion of geographic reach; and
- Mitigate counterparty risk through customer base growth and diversification.

Corporate/Other

Description of Assets

In addition to Corporate activities and assets, AltaGas' Corporate/Other segment includes 578 MW of operational gross capacity from remaining natural gas-fired and distributed generation power assets located in the U.S., primarily California and Colorado.

Specifically, the core remaining power assets in the Corporate/Other segment include two natural gas-fired plants with 577 MW of generating capacity in the United States: the 507 MW Blythe Energy Center (Blythe) in California and the 70 MW Brush II Facility (Brush) in Colorado which is pending sale. Blythe and Brush are both under Power Purchase Arrangements (PPA) with creditworthy utilities.

In Southern California, the 507 MW Blythe Energy Center utilizes gas-fired generation to produce power and serves the transmission grid operated by the California Independent System Operator (CAISO) to cover periods of high demand primarily driven by the Los Angeles area. Due to the structure of the long-term PPA with Southern California Edison (SCE), the majority of the revenue from the facility is derived from being available to produce and not from actual production, which reduces risk and provides stable cash flow. The facility is directly connected to an El Paso Gas Company natural gas pipeline for its primary supply and a Southern California Gas Company pipeline as a secondary supply source, and interconnects to SCE and CAISO via a 67-mile transmission line also owned by Blythe and is part of the Blythe Energy Center. In 2019, AltaGas announced the successful recontracting of the Blythe facility to SCE. With the approval of the PPA with SCE received by the California Public Utilities Commission in January 2020, Blythe is contracted under a PPA until December 31, 2023. Under the tolling agreement, SCE has exclusive rights to all capacity, energy, ancillary services, and resource adequacy benefits during the PPA term. In addition, AltaGas is in the process of permitting a new 60 MW stand-alone energy storage development project in Goleta, California. On February 9, 2022, AltaGas closed the sale of this energy storage project for proceeds of approximately US$15 million, subject to certain contingencies.

In the second quarter of 2021, AltaGas transferred ownership of the last remaining distributed generation project to the purchaser as part of the sale of its portfolio of U.S. distributed generation assets, which closed in 2019. Refer to Note 4 and Note 6 of the 2021 Annual Consolidated Financial Statements for additional details.

Consolidated Financial Review

	Three Months Ended December 31		Year Ended December 31	
($ millions, except where noted)	**2021**	2020	**2021**	2020
Revenue	**3,140**	1,689	**10,573**	5,587
Normalized EBITDA (1)	**341**	392	**1,490**	1,310
Income (loss) before income taxes	**(162)**	74	**446**	699
Net income (loss) applicable to common shares	**(156)**	48	**230**	486
Normalized net income (1)	**107**	147	**497**	396
Total assets	**21,593**	21,532	**21,593**	21,532
Total long-term liabilities	**11,335**	11,264	**11,335**	11,264
Invested capital (1) (2)	**253**	1,071	**798**	1,727
Cash flows used by investing activities	**(241)**	(980)	**(483)**	(1,211)
Dividends declared (3)	**71**	67	**281**	268
Cash from (used by) operations	**(157)**	7	**738**	773
Normalized funds from operations (1)	**287**	327	**1,198**	1,003
Normalized effective income tax rate (%) (1)	**23.6**	21.5	**22.1**	22.3
Effective income tax rate (%)	**17.9**	8.1	**23.8**	18.2

	Three Months Ended December 31		Year Ended December 31	
($ per share, except shares outstanding)	**2021**	2020	**2021**	2020
Net income (loss) per common share - basic	**(0.56)**	0.17	**0.82**	1.74
Net income (loss) per common share - diluted	**(0.56)**	0.17	**0.82**	1.74
Normalized net income - basic (1)	**0.38**	0.53	**1.78**	1.42
Normalized net income - diluted (1)	**0.38**	0.53	**1.76**	1.42
Dividends declared (3)	**0.25**	0.24	**1.00**	0.96
Cash from (used by) operations	**(0.56)**	0.03	**2.64**	2.77
Normalized funds from operations (1)	**1.03**	1.17	**4.28**	3.59
Shares outstanding - basic (millions)				
During the period (4)	**280**	279	**280**	279
End of period	**280**	279	**280**	279

(1) Non-GAAP financial measure; see discussion in the *Non-GAAP Financial Measures* section of this MD&A.
(2) In prior periods, invested capital did not include adjustments for the cost of removal of utility assets; however, beginning in the fourth quarter of 2021, Management has adjusted for these costs to better align with the investing section of the Consolidated Statements of Cash Flows. Comparative periods have been restated to reflect this change.
(3) Dividends declared per common share per month: $0.08 beginning December 2018, increased to $0.0833 per share beginning December 2020.
(4) Weighted average.

Three Months Ended December 31

Normalized EBITDA for the fourth quarter of 2021 was $341 million, compared to $392 million for the same quarter in 2020. Factors negatively impacting AltaGas' normalized EBITDA in the fourth quarter of 2021 included lower gas and power margins from WGL's retail marketing business, a hedge loss associated with revenue recognized for export cargos loaded at the end of the third quarter at market spot prices, cessation of AFUDC related to MVP, the impact of the sale of the majority of WGL Midstream's commodity business in the second quarter of 2021, amortization of a contract asset at Gordondale related to a blend and extend contract that was entered into in 2018 with the impact of the lower processing fees being recognized for accounting purposes starting in 2021, the impact of warmer weather in Michigan and the District of Columbia, and lower realized frac spreads (inclusive of hedges). Factors positively impacting normalized EBITDA included the impact of Washington Gas' 2020 Maryland and District of Columbia rate cases, impacts from the consolidation of Petrogas, higher export volumes at RIPET, higher extracted NGL volumes, and higher revenue from accelerated pipe replacement program spend. For the three months ended December 31, 2021, the average Canadian/U.S. dollar exchange rate decreased to 1.26 from an average of 1.30 in the same quarter of 2020, resulting in a decrease in normalized EBITDA of approximately $8 million.

Loss before income taxes for the fourth quarter of 2021 was $162 million, compared to income of $74 million for the same quarter in 2020. The decrease was mainly due to the provision recorded on AltaGas' investment in MVP, the same previously referenced factors impacting normalized EBITDA, and the absence of the gain recorded on the re-measurement of AltaGas' previously held equity investment in AltaGas Idemitsu Joint Venture LP (AIJVLP) upon acquisition of Petrogas, partially offset by the absence of the impairment of the Alton Natural Gas Storage Project (Alton) in the fourth quarter of 2020, the absence of the dilution loss and other adjustments to equity income related to the acquisition of Petrogas, and lower unrealized losses on risk management contracts. Net loss applicable to common shares for the fourth quarter of 2021 was $156 million ($0.56 per share), compared to income of $48 million ($0.17 per share) for the same quarter in 2020. The change was due to the same previously referenced factors impacting loss before income taxes and higher net income applicable to non-controlling interests, partially offset by lower income tax expense.

Normalized funds from operations for the fourth quarter of 2021 was $287 million ($1.03 per share), compared to $327 million ($1.17 per share) for the same quarter in 2020. The decrease was mainly due to the same previously referenced factors impacting normalized EBITDA.

Cash used by operations for the fourth quarter of 2021 was $157 million ($0.56 per share), compared to cash from operations of $7 million ($0.03 per share) for the same quarter in 2020. The decrease was mainly due to lower net income after taxes (after adjusting for non-cash items) and unfavourable variances in the net change in operating assets and liabilities, primarily as a result of higher commodity prices. Please refer to the *Liquidity* section of this MD&A for further details on the variance in cash from operations.

In the fourth quarter of 2021, AltaGas recorded pre-tax losses on dispositions of assets of approximately $1 million related to minor Midstream asset sales. In addition, in the fourth quarter of 2021, AltaGas recorded pre-tax provisions on assets of approximately $6 million ($2 million after-tax) primarily related to non-core development stage Midstream projects that are no longer being developed and the Parks at Walter Reed thermal plant in Washington, D.C. which was impaired as the carrying value exceeded future expected cash flows from the asset. In the fourth quarter of 2021, AltaGas recorded a pre-tax provision on equity investments of approximately $271 million ($209 million after-tax) in the Consolidated Statements of Income under the line item "income (loss) from equity investments" related to its investment in MVP. The provision is a result of continued legal and regulatory challenges associated with the Mountain Valley Pipeline and MVP Southgate projects. In the fourth quarter of 2020, upon the acquisition of Petrogas, AltaGas recorded a gain on re-measurement of the Company's previously held equity investment in AIJVLP of approximately $22 million. In addition, in the fourth quarter of 2020, AltaGas recorded pre-tax provisions on assets of approximately $104 million ($79 million after-tax), primarily related to Alton.

Operating and administrative expense for the fourth quarter of 2021 was $403 million, compared to $342 million for the same quarter in 2020. The increase was mainly due to the inclusion of Petrogas' operating and administrative expenses upon consolidation and higher costs from increased activity at RIPET. Depreciation and amortization expense for the fourth quarter of 2021 was $105 million, compared to $108 million for the same quarter in 2020. The slight decrease was mainly due to the impact of the sale of the majority of WGL Midstream's commodity business, partially offset by amortization expense on Petrogas assets upon consolidation. Interest expense for the fourth quarter of 2021 was $67 million, compared to $68 million for the same quarter in 2020. The slight decrease was predominantly due to lower average interest rates and lower average foreign exchange rates in 2021, partially offset by higher average debt balances.

AltaGas recorded income tax recovery of $28 million for the fourth quarter of 2021 compared to expense of $5 million in the same quarter in 2020. The decrease in income tax expense was mainly due to the tax impact of the provision recorded on AltaGas' investment in MVP, which created a loss before taxes in the fourth quarter of 2021.

Normalized net income was $107 million ($0.38 per share) for the fourth quarter of 2021, compared to $147 million ($0.53 per share) reported for the same quarter in 2020. The decrease was mainly due to the same factors impacting normalized EBITDA net of income taxes, and higher net income applicable to non-controlling interests, partially offset by lower interest expense and lower depreciation and amortization expense. Normalizing items in the fourth quarter of 2021 increased normalized net income by $262 million and included after-tax amounts related to transaction costs and acquired contingencies related to acquisitions and dispositions, provisions on assets, provisions on investments accounted for by the equity method, unrealized losses on risk management contracts, losses on sale of assets, and non-controlling interest portion of non-GAAP adjustments. Normalizing items in the fourth quarter of 2020 increased normalized net income by $99 million and included after-tax amounts related to transaction costs and acquired contingencies related to acquisitions and dispositions, restructuring costs, provisions on assets, unrealized losses on risk management contracts, gains on sale of assets, dilution loss and other adjustments to equity income related to the acquisition of Petrogas, and the gain recorded on the re-measurement of AltaGas' previously held equity investment in AIJVLP upon acquisition of Petrogas. Please refer to the *Non-GAAP Financial Measures* section of this MD&A for further details on normalization adjustments.

Year Ended December 31

Normalized EBITDA for the year ended December 31, 2021 was $1,490 million, compared to $1,310 million in 2020. Factors positively impacting normalized EBITDA included impacts from the consolidation of Petrogas, favorable storage and transportation margins and higher storage withdrawals at WGL Midstream in the first quarter of 2021, higher export volumes at RIPET, the impact of Washington Gas' 2020 Maryland and District of Columbia rate cases, higher processed volumes at the NEBC facilities due to NEBC growth projects placed into service, higher returns on pension assets, increased earnings from the cogeneration plants at Harmattan due to higher Alberta power prices, higher revenue from accelerated pipe replacement program spend, and higher gas margins from WGL's retail marketing business due to favourable pricing. These were partially offset by the impact of asset sales, including AltaGas Canada Inc. (ACI), the majority of WGL Midstream's commodity business, Pomona Energy Storage Inc. (Pomona) and AltaGas Ripon Energy Inc. (Ripon), as well as cessation of AFUDC related to MVP, higher expenses related to employee incentive plans as a result of the increasing share price in 2021, amortization of a contract asset at Gordondale related to a blend and extend contract that was entered into in 2018 with the impact of the lower processing fees being recognized for accounting purposes starting in 2021, lower realized merchant margins at RIPET (inclusive of hedges), and the absence of recoveries related to CEWS in 2020. For the year ended December 31, 2021, the average Canadian/U.S. dollar exchange rate decreased to 1.25 from an average of 1.34 in 2020, resulting in an decrease in normalized EBITDA of approximately $49 million.

Income before income taxes for the year ended December 31, 2021 was $446 million, compared to $699 million in 2020. The decrease was mainly due the provision recorded on AltaGas' investment in MVP in the fourth quarter of 2021, the absence of gains on certain 2020 asset sales, including ACI, distributed generation projects which were transferred to the purchaser in the first quarter of 2020, Pomona, and Ripon, as well as the absence of the gain recorded on the re-measurement of AltaGas' previously held equity investment in AIJVLP upon acquisition of Petrogas, provisions related to the sale of the majority of WGL Midstream's commodity business, and higher depreciation expense, partially offset by to the same previously referenced factors impacting normalized EBITDA, the absence of the provision on Alton, the absence of the dilution loss and other adjustments to equity income related to the acquisition of Petrogas, higher unrealized gains on risk management contracts, and the absence of provision on equity investments related to the Constitution pipeline project (Constitution) which was cancelled in February 2020. Net income applicable to common shares for the year ended December 31, 2021 was $230 million ($0.82 per share), compared to $486 million ($1.74 per share) in 2020. The change was due to the same previously referenced factors impacting income before income taxes and higher net income applicable to non-controlling interests as a result of the Petrogas acquisition, partially offset by lower income tax expense.

Normalized funds from operations for the year ended December 31, 2021 was $1,198 million ($4.28 per share), compared to $1,003 million ($3.59 per share) in 2020. The increase was mainly due to the same previously referenced factors impacting normalized EBITDA, partially offset by higher current income tax expense.

Cash from operations for the year ended December 31, 2021 was $738 million ($2.64 per share), compared to $773 million ($2.77 per share) in 2020. The decrease was mainly due to unfavourable variances in the net change in operating assets and liabilities and higher current tax expense on asset sales, partially offset by higher 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.

In 2021, AltaGas recorded pre-tax gains on dispositions of assets of approximately $6 million. This was primarily comprised of a pre-tax loss of $1 million on the last remaining U.S. distributed generation project which was sold in 2019 but transferred to the purchaser during the second quarter of 2021, a pre-tax gain of $3 million on the sale of the majority of WGL Midstream's commodity business, a pre-tax gain of $1 million on minor Midstream asset sales, and $3 million of 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 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 obligations. In addition, in 2021, AltaGas recorded pre-tax provisions on assets of approximately $64 million ($48 million after-tax) primarily related to the sale of the majority of WGL Midstream's commodity business and the previously mentioned provisions recorded in the fourth quarter of 2021. In 2021, AltaGas also recorded the previously mentioned provision on equity investments of $271 million ($209 million after-tax) related to its investment in MVP. In 2020, AltaGas recorded a pre-tax gain of $206 million on the disposition of its equity investment in ACI and a pre-tax gain on disposition of assets of $17 million. This was comprised of a pre-tax gain of $9 million related to certain distributed generation projects which were transferred to the purchaser in 2020, a pre-tax gain of $5 million on the disposition of Pomona, and a pre-tax gain of $3 million on the disposition of Ripon. In 2020, upon the acquisition of Petrogas, AltaGas also recorded the previously mentioned gain on the re-measurement of its previously held equity investment in AIJVLP of approximately $22 million. In 2020, AltaGas recorded pre-tax provisions on assets of approximately $109 million ($81 million after-tax) primarily related to Alton, certain U.S. distributed generation projects which had not yet transferred to the purchaser, and land parcels located near the Harmattan gas processing plant. In addition, in 2020, AltaGas recorded a pre-tax provision on equity investments of approximately $7 million ($6 million after-tax) for costs associated with Constitution which was canceled in February 2020.

Operating and administrative expense for the year ended December 31, 2021 was $1,476 million, compared to $1,267 million in 2020. The increase was mainly due to the inclusion of Petrogas' operating and administrative expenses upon consolidation, higher costs from increased activity at RIPET and the NEBC growth projects which were placed in service in the second and third quarters of 2020, higher expenses related to employee incentive plans as a result of the increasing share price in 2021, and the absence of recoveries related to CEWS recorded in 2020. Depreciation and amortization expense for the year ended December 31, 2021 was $422 million, compared to $414 million in 2020. The increase was mainly due to amortization expense on Petrogas assets upon consolidation and new assets placed in-service, partially offset by an amortization adjustment related to the derecognition of an intangible liability in the second quarter of 2020. Interest expense for the year ended December 31, 2021 was $275 million, compared to $274 million in 2020. The slight increase was due to lower capitalized interest and higher average debt balances, partially offset by lower average interest rates and lower average foreign exchange rates in 2021.

AltaGas recorded income tax expense of $106 million for the year ended December 31, 2021 compared to $127 million in 2020. The decrease in tax expense was mainly due to the tax impact of the provision recorded on AltaGas' investment in MVP in the fourth quarter of 2021, partially offset by the absence of gains taxed at 50 percent of the normal Canadian rate (primarily related to the gain on sale of ACI in the first quarter of 2020).

Normalized net income was $497 million ($1.78 per share) for the year ended December 31, 2021, compared to $396 million ($1.42 per share) in 2020. The increase was mainly due to the same previously referenced factors impacting normalized EBITDA, partially offset by higher net income applicable to non-controlling interests, higher interest expense, higher depreciation and amortization expense, and higher income tax expense. Normalizing items in the year ended December 31, 2021 increased normalized net income by $267 million and included after-tax amounts related to gains on sale of assets, transaction costs and acquired contingencies related to acquisitions and dispositions, restructuring costs, provisions on assets, provisions on investments accounted for by the equity method, and unrealized gains on risk management contracts. Normalizing items in the year ended December 31, 2020 reduced normalized net income by $90 million and included after-tax amounts related to gains on sale of assets, transaction costs related to acquisitions and dispositions, restructuring costs, provisions on assets, provisions on investments accounted for by the equity method, dilution loss and other adjustments to equity income related to the acquisition of Petrogas, COVID-19 related costs, gain recorded on the re-measurement of AltaGas' previously held equity investment in AIJVLP upon acquisition of Petrogas, and unrealized gains on risk management contracts. Please refer to the *Non-GAAP Financial Measures* section of this MD&A for further details on normalization adjustments.

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 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, net debt to total capitalization, invested capital, and net invested capital throughout this MD&A have the meanings as set out in this section.

Normalized EBITDA

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2021**	2020	**2021**	2020
Income (loss) before income taxes (GAAP financial measure)	**$ (162)**	$ 74	**$ 446**	$ 699
Add:				
Depreciation and amortization	**105**	108	**422**	414
Interest expense	**67**	68	**275**	274
EBITDA	**$ 10**	$ 250	**$ 1,143**	$ 1,387
Add (deduct):				
Transaction costs and acquired contingencies related to acquisitions and dispositions (1)	**16**	5	**33**	22
Unrealized losses (gains) on risk management contracts (2)	**33**	24	**(18)**	(21)
Losses (gains) on sale of assets (3)	**1**	—	**(6)**	(223)
Gain on re-measurement of previously held equity investment in AIJVLP (4)	**—**	(22)	**—**	(22)
Dilution loss and other adjustments to equity investments (4)	**—**	26	**—**	42
Restructuring costs (5)	**—**	4	**1**	6
COVID-19 related costs (6)	**—**	—	**—**	2
Provisions on assets	**6**	104	**64**	109
Provisions on investments accounted for by the equity method (7)	**271**	—	**271**	7
Accretion expenses	**4**	2	**6**	5
Foreign exchange gains	**—**	(1)	**(4)**	(4)
Normalized EBITDA	**$ 341**	$ 392	**$ 1,490**	$ 1,310

(1) Comprised of transaction costs and acquired contingencies related to acquisitions and dispositions of assets and/or equity investments in the period. These costs and contingencies are included in the "cost of sales", "operating and administrative", and "other income" line items on the Consolidated Statements of Income. Transaction costs include expenses, such as legal fees, that are directly attributable to the acquisition or disposition. The acquired contingencies relate to the acquisition of Petrogas and include amounts for additional contingent consideration for the purchase of Petrogas as well as certain acquired indirect tax liabilities. Please refer to Note 3 and Note 4 of the 2021 Annual Consolidated Financial Statements for further details regarding AltaGas' acquisitions and dispositions.

(2) Included in the "revenue" and “cost of sales” line items on the Consolidated Statements of Income. Please refer to Note 23 of the 2021 Annual Consolidated Financial Statements for further details regarding AltaGas' risk management activities.

(3) Included in the "other income" line item on the Consolidated Statements of Income. Please refer to Note 4 of the 2021 Annual Consolidated Financial Statements for further details regarding AltaGas' disposition of assets in the period.

(4) Relates to adjustments to equity income recognized in 2020 related to the investment in Petrogas. These amounts are included in the “income (loss) from equity investments” line item on the Consolidated Statements of Income.

(5) Comprised of costs related to a workforce optimization program. These costs are included in the “operating and administrative” line item on the Consolidated Statements of Income.

(6) COVID-19 related costs are primarily comprised of credit losses that were incremental and directly attributable to the COVID-19 pandemic and charges incurred to support remote work arrangements. As these costs would not have otherwise been incurred, it has been included as a normalizing item. Credit losses are included in the “revenue” line item as a reduction to revenue, and the additional charges incurred to support remote work arrangements are included in the “operating and administrative” line item on the Consolidated Statements of Income.

(7) Relates to the provisions recorded on AltaGas' investment in MVP in the fourth quarter of 2021 and the Constitution pipeline project which was canceled in February 2020. The provisions are included in the “income (loss) from equity investments” line item on the Consolidated Statements of Income.

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 using income 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 December 31		Year Ended December 31	
($ millions)		**2021**	2020	**2021**	2020
Net income (loss) applicable to common shares (GAAP financial measure)		**$ (156)**	$ 48	**$ 230**	$ 486
Add (deduct) after-tax:					
Transaction costs and acquired contingencies related to acquisitions and dispositions (1)		**13**	3	**28**	18
Unrealized losses (gains) on risk management contracts (2)		**21**	17	**(10)**	(18)
Losses (gains) on sale of assets (3)		**15**	(7)	**—**	(204)
Non-controlling interest portion of non-GAAP adjustments (4)		**3**	—	**(9)**	—
Gain on re-measurement of previously held equity investment in AIJVLP (5)		**—**	(22)	**—**	(22)
Dilution loss and other adjustments to equity investments (5)		**—**	26	**—**	42
Restructuring costs (6)		**—**	3	**1**	5
COVID-19 related costs (7)		**—**	—	**—**	2
Provisions on assets		**2**	79	**48**	81
Provisions on investments accounted for by the equity method (8)		**209**	—	**209**	6
Normalized net income		**$ 107**	$ 147	**$ 497**	$ 396

(1) Comprised of transaction costs and acquired contingencies related to acquisitions and dispositions of assets and/or equity investments in the period. The pre-tax costs and contingencies are included in the "cost of sales", "operating and administrative", and "other income" line items on the Consolidated Statements of Income. Transaction costs include expenses, such as legal fees, that are directly attributable to the acquisition or disposition. The acquired contingencies relate to the acquisition of Petrogas and include amounts for additional contingent consideration for the purchase of Petrogas as well as certain acquired indirect tax liabilities. Please refer to Note 3 and Note 4 of the 2021 Annual Consolidated Financial Statements for further details regarding AltaGas' acquisitions and dispositions.

(2) The pre-tax amounts are included in the "revenue" and “cost of sales” line items on the Consolidated Statements of Income. Please refer to Note 23 of the 2021 Annual Consolidated Financial Statements 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. Please refer to Note 4 of the 2021 Annual Consolidated Financial Statements for further details regarding AltaGas' disposition of assets in the period. The after-tax amount also includes the impact of the increase in accumulated state deferred income tax liabilities caused by the elimination of the WGL Midstream business from AltaGas' consolidated U.S. tax group.

(4) 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.

(5) Relates to adjustments to equity income recognized in 2020 related to the investment in Petrogas. The pre-tax amounts are included in the “income (loss) from equity investments” line item on the Consolidated Statements of Income.

(6) Comprised of costs related to a workforce optimization program. The pre-tax costs are included in the “operating and administrative” line item on the Consolidated Statements of Income.

(7) COVID-19 related costs are primarily comprised of credit losses that were incremental and directly attributable to the COVID-19 pandemic and charges incurred to support remote work arrangements. As these costs would not have otherwise been incurred, it has been included as a normalizing item. Credit losses are included in the “revenue” line item as a reduction to revenue, and the additional charges incurred to support remote work arrangements are included in the “operating and administrative” line item on the Consolidated Statements of Income.

(8) Relates to the provisions recorded on AltaGas' investment in MVP in the fourth quarter of 2021 and the Constitution pipeline project which was canceled in February 2020. The pre-tax provisions are included in the “income (loss) from equity investments” line item on the Consolidated Statements of Income.

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

Normalized Funds From Operations

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2021**	2020	**2021**	2020
Cash from (used by) operations (GAAP financial measure)	**$ (157)**	$ 7	**$ 738**	$ 773
Add (deduct):				
Net change in operating assets and liabilities	**437**	311	**410**	203
Asset retirement obligations settled	**3**	2	**10**	4
Funds from operations	**$ 283**	$ 320	**$ 1,158**	$ 980
Add (deduct):				
Transaction costs and acquired contingencies related to acquisitions and dispositions [1]	**16**	5	**33**	17
Current tax expense (recovery) on asset sales [2]	**(12)**	(2)	**6**	(2)
Restructuring costs [3]	**—**	4	**1**	6
COVID-19 related costs [4]	**—**	—	**—**	2
Normalized funds from operations	**$ 287**	$ 327	**$ 1,198**	$ 1,003

(1) Comprised of costs and acquired contingencies related to acquisitions and dispositions of assets and/or equity investments in the period. These costs and contingencies exclude non-cash amounts and are included in the "cost of sales", "operating and administrative", and "other income" line items on the Consolidated Statements of Income. Transaction costs include expenses, such as legal fees, that are directly attributable to the acquisition or disposition. The acquired contingencies relate to the acquisition of Petrogas and include amounts for additional contingent consideration for the purchase of Petrogas as well as certain acquired indirect tax liabilities. Please refer to Note 3 and Note 4 of the 2021 Annual Consolidated Financial Statements for further details regarding AltaGas' acquisitions and dispositions.

(2) Primarily related to the sale of WGL Midstream's commodity business. These expenses (recoveries) are included in the "current income tax expense" line item on the Consolidated Statements of Income.

(3) Comprised of costs related to a workforce optimization program. These costs are included in the “operating and administrative” line item on the Consolidated Statements of Income.

(4) COVID-19 related costs are primarily comprised of credit losses that were incremental and directly attributable to the COVID-19 pandemic and charges incurred to support remote work arrangements. As these costs would not have otherwise been incurred, it has been included as a normalizing item. Credit losses are included in the “revenue” line item as a reduction to revenue, and the additional charges incurred to support remote work arrangements are included in the “operating and administrative” line item on the Consolidated Statements of Income.

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 (used in) operations or other cash flow measures calculated in accordance with GAAP.

Normalized Income Tax Expense

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2021**	2020	**2021**	2020
Income tax expense (recovery) (GAAP financial measure)	**$ (28)**	$ 5	**$ 106**	$ 127
Add (deduct) tax impact of:				
Transaction costs and acquired contingencies related to acquisitions and dispositions	**3**	2	**6**	4
Unrealized losses (gains) on risk management contracts	**12**	6	**(9)**	(4)
Losses (gains) on sale of assets [1]	**(14)**	7	**(6)**	(19)
Restructuring costs	**—**	1	**—**	1
Provisions on assets	**4**	25	**16**	28
Provisions on investments accounted for by the equity method	**62**	—	**62**	1
Normalized income tax expense	**$ 39**	$ 46	**$ 175**	$ 138

(1) Includes the impact of the increase in accumulated state deferred income tax liabilities caused by the elimination of the WGL Midstream business from AltaGas' consolidated U.S. tax group.

The above table provides a reconciliation of normalized income tax expense from the GAAP financial measure, income tax expense. 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 and Net Debt to Total Capitalization

Net debt and net debt to total capitalization are used by the Corporation to monitor its capital structure and financing requirements. 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 (excluding third-party project financing obtained for the construction of certain energy management services projects), plus current and long-term portions of long-term debt, less cash and cash equivalents. Total capitalization is defined as net debt plus shareholders' equity and non-controlling interests. Additional information regarding these non-GAAP measures can be found under the *Capital Resources* section of this MD&A.

Net Invested Capital

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2021**	2020 [4]	**2021**	2020 [4]
Cash used in investing activities (GAAP financial measure)	**$ 241**	$ 980	**$ 483**	$ 1,211
Add (deduct):				
Net change in non-cash capital expenditures [1]	**11**	53	**(33)**	33
Cash acquired in business acquisitions [2]	**—**	40	**—**	40
Contributions from non-controlling interests [3]	**—**	(2)	**(1)**	(7)
Net invested capital	**$ 252**	$ 1,071	**$ 449**	$ 1,277

(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 31 of the 2021 Annual Consolidated Financial Statements for further details.

(2) Related to the cash acquired as part of the Petrogas Acquisition. Business acquisitions are presented net of cash acquired on the Consolidated Statements of Cash Flows. Please refer to Note 3 of the 2021 Annual Consolidated Financial Statements for further details regarding the acquisition.

(3) Comprised of partner recoveries for capital expenditures incurred for the Ridley Island Propane Export Terminal. These recoveries are included in "contributions from non-controlling interests" under financing activities in the Consolidated Statements of Cash Flows, however as Management views this as a part of AltaGas' invested capital, it has been included in the calculation of net invested capital.

(4) In prior periods, invested capital did not include adjustments for the cost of removal of utility assets; however, beginning in the fourth quarter of 2021, Management has adjusted for these costs to better align with the investing section of the Consolidated Statements of Cash Flows. Comparative periods have been restated to reflect this change. Additionally, 2020 invested capital has been revised to include the $7 million final payment related to the Constitution pipeline project that was canceled in February 2020, also to better align with the investing section of the Consolidated Statements of Cash Flows.

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 any proceeds from disposals of assets and equity investments in the period. Net invested capital is calculated based on the investing activities section in the Consolidated Statements of Cash Flows, adjusted for items such as non-cash capital expenditures, cash acquired in business acquisitions, 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 December 31		Year Ended December 31	
($ millions)	**2021**	2020	**2021**	2020
Normalized EBITDA	**$ 341**	$ 392	**$ 1,490**	$ 1,310
Add (deduct):				
Depreciation and amortization	**(105)**	(108)	**(422)**	(414)
Interest expense	**(67)**	(68)	**(275)**	(274)
Income tax expense	**28**	(5)	**(106)**	(127)
Normalizing items impacting income taxes (1)	**(67)**	(42)	**(69)**	(12)
Accretion expenses	**(4)**	(2)	**(6)**	(5)
Foreign exchange gains	**—**	1	**4**	4
Non-controlling interest portion of non-GAAP adjustments (2)	**3**	—	**(9)**	—
Net income applicable to non-controlling interests	**(9)**	(5)	**(57)**	(20)
Preferred share dividends	**(13)**	(16)	**(53)**	(66)
Normalized net income	**$ 107**	$ 147	**$ 497**	$ 396

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

(2) 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.

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.

	Three Months Ended December 31		Year Ended December 31	
($ millions, except where noted)	**2021**	2020	**2021**	2020
Normalized net income	**$ 107**	$ 147	**$ 497**	$ 396
Add (deduct):				
Normalized income tax expense [(1)]	**39**	46	**175**	138
Net income applicable to non-controlling interests	**9**	5	**57**	20
Non-controlling interest portion of non-GAAP adjustments [(2)]	**(3)**	—	**9**	—
Preferred share dividends	**13**	16	**53**	66
Normalized net income before taxes	**$ 165**	$ 214	**$ 791**	$ 620
Normalized effective income tax rate (%) [(3)]	**23.6**	21.5	**22.1**	22.3

(1) Calculated in the section above.

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

Results of Operations by Reporting Segment

Normalized EBITDA [(1)]	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2021**	2020	**2021**	2020
Utilities	**$ 238**	$ 259	**$ 771**	$ 788
Midstream	**102**	128	**734**	473
Sub-total: Operating Segments	**$ 340**	$ 387	**$ 1,505**	$ 1,261
Corporate/Other	**1**	5	**(15)**	49
	$ 341	$ 392	**$ 1,490**	$ 1,310

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

Income (Loss) Before Income Taxes	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2021**	2020	**2021**	2020
Utilities	**$ 64**	$ 157	**$ 538**	$ 687
Midstream	**(151)**	(36)	**242**	235
Sub-total: Operating Segments	**$ (87)**	$ 121	**$ 780**	$ 922
Corporate/Other	**(75)**	(47)	**(334)**	(223)
	$ (162)	$ 74	**$ 446**	$ 699

Revenue	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2021**	2020	**2021**	2020
Utilities	**$ 1,261**	$ 1,092	**$ 3,936**	$ 3,817
Midstream	**1,852**	572	**6,535**	1,636
Sub-total: Operating Segments	**$ 3,113**	$ 1,664	**$ 10,471**	$ 5,453
Corporate/Other	**27**	34	**104**	135
Intersegment eliminations	**—**	(9)	**(2)**	(1)
	$ 3,140	$ 1,689	**$ 10,573**	$ 5,587

Utilities

Operating Statistics

	Three Months Ended December 31		Year Ended December 31	
	2021	2020	**2021**	2020
Natural gas deliveries - end-use (Bcf) (1)	**44.0**	50.0	**155.9**	151.7
Natural gas deliveries - transportation (Bcf) (1)	**31.2**	35.6	**124.5**	124.1
Service sites (thousands) (2)	**1,689**	1,672	**1,689**	1,672
Degree day variance from normal - SEMCO Gas (%) (3)	**(15.0)**	(4.4)	**(10.0)**	(4.6)
Degree day variance from normal - ENSTAR (%) (3)	**11.9**	0.2	**11.0**	5.6
Degree day variance from normal - Washington Gas (%) (3) (4)	**(12.7)**	(10.6)	**(7.0)**	(11.2)
Retail energy marketing - gas sales volumes (Mmcf)	**16,299**	18,053	**58,589**	59,782
Retail energy marketing - electricity sales volumes (GWh)	**3,167**	3,257	**13,355**	13,607

(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, during the prior 10 years for ENSTAR, 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 that 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.

Regulatory Metrics

	Year Ended December 31	
	2021	2020
Approved ROE (%) (1)	**9.6**	9.6
Approved return on debt (%) (1)	**4.7**	5.1
Rate base *($ millions)* (2) (3) (4)	**4,655**	4,291

(1) Weighted average of all the regulated utilities.
(2) Rate base is indicative of the earning potential of each utility over time. Approved revenue requirement for each utility is typically based on the rate base as approved by the regulator for the respective rate application, but may differ from the rate base indicated above.
(3) Reflects AltaGas' 65 percent interest in Cook Inlet Natural Gas Storage Alaska LLC.
(4) In U.S. dollars.

During the fourth quarter of 2021, AltaGas' Utilities segment experienced warmer weather at SEMCO, colder weather at ENSTAR, and warmer at Washington Gas compared to the same quarter of 2020.

For the year ended December 31, 2021, AltaGas' Utilities segment experienced warmer weather at SEMCO, colder weather at ENSTAR, and colder weather at Washington Gas compared to 2020.

Service sites at December 31, 2021 increased by approximately 17 thousand sites compared to December 31, 2020 due to growth in customer base.

In the fourth quarter of 2021, U.S. retail gas sales volumes were 16,299 Mmcf, compared to 18,053 Mmcf in the same quarter of 2020. The decrease was primarily due to warmer weather compared to the same quarter of 2020. In the fourth quarter of 2021, U.S. retail electricity sales volumes were 3,167 GWh compared to 3,257 GWh in the same quarter of 2020. The decrease was primarily due to warmer weather.

For the year ended December 31, 2021, U.S. retail gas sales volumes were 58,589 Mmcf, compared to 59,782 Mmcf in the same period in 2020. The slight decrease was primarily due to fewer residential gas customers served in the year ended December 31, 2021 compared to 2020. For the year ended December 31, 2021, U.S. retail electricity sales volumes were 13,355 GWh compared to 13,607 GWh in the same period in 2020. The decrease was primarily due to more moderate weather and a decrease in customers served.

Three Months Ended December 31

The Utilities segment reported normalized EBITDA of $238 million in the fourth quarter of 2021, compared to $259 million in the same quarter in 2020. The decrease in normalized EBITDA was mainly due to lower gas and power margins from WGL's retail marketing business, an impact of approximately $7 million due to the weaker U.S. dollar, warmer weather in Michigan and the District of Columbia, and higher general and administrative expenses mainly related to technology costs and professional fees, partially offset by the impact of Washington Gas' 2020 Maryland and District of Columbia rate cases, higher returns on pension assets, and higher revenue from accelerated pipe replacement program spend.

The Utilities segment income before income taxes was $64 million in the fourth quarter of 2021, compared to $157 million in the same quarter in 2020. The decrease was mainly due to the same previously referenced factors impacting normalized EBITDA and higher losses on unrealized risk management contracts mainly within the retail marketing business.

Year Ended December 31

The Utilities segment reported normalized EBITDA of $771 million in the year ended December 31, 2021, compared to $788 million in 2020. The decrease in normalized EBITDA was mainly due to an impact of approximately $40 million due to the weaker U.S. dollar, higher general and administrative expenses mainly related to technology costs and professional fees, the impact of the sale of ACI in 2020, lower power margins from WGL's retail marketing business due to lower volumes and unit margins, Virginia rate refund adjustments in 2020, and warmer weather in Michigan, partially offset by the impact of Washington Gas' 2020 Maryland and District of Columbia rate cases, higher returns on pension assets, higher revenue from accelerated pipe replacement program spend, higher gas margins from WGL's retail marketing business due to favourable pricing, colder weather in the District of Columbia and Alaska, and customer growth.

The Utilities segment income before income taxes was $538 million in the year ended December 31, 2021, compared to $687 million in 2020. The decrease was mainly due to the absence of the gain on the disposition of ACI and the same previously referenced factors impacting normalized EBITDA, partially offset by higher gains on risk management contracts mainly within the retail marketing business.

In 2020, the Utilities segment recognized a pre-tax gain of $206 million on the disposition of ACI.

Rate Case Updates

Utility/ Jurisdiction	Date Filed	Request	Status	Expected Timing of Decision
Washington Gas - Maryland	August 2020	US$27 million increase in base rates, including US$6 million currently collected through the Strategic Infrastructure Development Enhancement Plan (STRIDE) surcharges for system upgrades. Therefore, the incremental amount of the base rate increase requested was approximately US$21 million.	Washington Gas filed this rate case on August 28, 2020. On February 12, 2021, the Public Utility Law Judge (PULJ) issued a Proposed Order in the Case and an ERRATA filing correcting of the Proposed Order on February 19, 2021. The Proposed Order, as corrected, authorizes Washington Gas to increase its Maryland natural gas distribution rates by approximately US$13 million (including US$5 million for the STRIDE surcharge), reflecting a return of equity of 9.70 percent. On April 9, 2021, after considering the appeals, the PSC of MD issued an order which authorized Washington Gas to increase its Maryland natural gas distribution rates by approximately US$13 million (including US$5 million currently collected through the STRIDE surcharge), reflecting a return on equity of 9.70 percent. The revenue increase became effective on March 26, 2021. On May 14, 2021, the Maryland Office of People's Counsel (MD OPC) filed a petition for re-hearing and on June 2, 2021, Washington Gas filed an opposition to the re-hearing. On July 29, 2021, the PSC of MD denied the petition for rehearing. On August 31, 2021, the MD OPC filed an appeal of the PSC of MD's denial of their petition for a re-hearing with the Circuit Court of Baltimore. Washington Gas has filed a notice of intervention. The MD OPC's Initial Memorandum was filed on December 15, 2021, and the PSC of MD and Washington Gas filed their Answering Memoranda on January 14, 2022. The MD OPC's following Reply Memorandum was filed on January 31, 2022, and the Circuit Court trial was held on February 16, 2022. On February 25, 2022, the Circuit Court of Baltimore City reversed the July 29, 2021 order from the PSC of MD and remanded two issues back to the PSC of MD.	Final order issued April 2021
CINGSA	July 2021	US$1.9 million revenue increase.	On July 1, 2021, CINGSA filed a rate case with the RCA seeking approval for approximately US$1.9 million revenue increase based on US$105.5 million rate base, 11.9 percent ROE and 59.99 percent equity thickness. The filing proposed an across-the-board 2 percent interim rate increase to be effective August 1, 2021, which the RCA approved on July 29, 2021. Discovery on CINGSA's direct testimony closed on December 30, 2021, CINGSA filed supplemental testimony on January 31, 2022, and interveners' testimony was due February 11, 2022. Evidentiary hearing is scheduled for June 2022, and a decision is expected around the end of the third quarter of 2022.	Around Q3 2022

COVID-19 Related Orders

Utility/ Jurisdiction	Moratoriums	Customer Programs	Regulatory Assets Recorded as at December 31, 2021 ($USD)
Washington Gas - District of Columbia	The moratorium on evictions and utility shutoffs triggered by the pandemic ended on October 12, 2021. However, the September 15, 2021 Order discussed below regarding call response time standards prevents disconnection until Washington Gas can meet the PSC of DC's requirements.	On April 19, 2021, Washington Gas filed an Arrearage Management Plan (AMP) proposal designed to help customers: 1) lower or eliminate existing COVID-19 related arrearages, 2) bring accounts current, 3) improve payment behavior on customers' new bills, and 4) avoid disconnection and allow customers to remain current in their payment obligations. Under the proposed AMP plan, each participating customer would be enrolled in the plan for approximately 12 months. After an eligible customer enrolls in the program and pays each new monthly amount due on a timely basis, Washington Gas will grant a pro-rated monthly arrearage reduction amount toward the goal of full arrearage elimination at the end of the 12 month period. On August 9, 2021, the PSC of DC approved Washington Gas' AMP. On October 8, 2021, Washington Gas filed new tariff provisions regarding the AMP and implemented the AMP starting November 1, 2021.	$3.5 million, and an additional $5.6 million of unrecorded late payment fees.
Washington Gas - Maryland	The shut-off moratorium on Tier 1 and 2 customers ended in November 2021. The COVID related shut-off moratorium for Tier 3 customers ended in November 2020. However, as a result of customer service matters, dunning activities, including service disconnections were suspended for all customers beginning in September 2021.	On February 15, 2021, the Maryland General Assembly passed the Recovery for the Economy, Livelihoods, Industries, Entrepreneurs and Families Act (RELIEF Act). The RELIEF Act includes approximately US$83 million in funds to help Maryland residential customers who are in arrears. On June 15, 2021, the PSC of MD issued an order allocating US$5.7 million to Washington Gas to be reflected on customer bills. The funds were received in July and Washington Gas has applied the amounts in full to customer accounts.	$0.5 million, and an additional $1.5 million of unrecorded late payment fees.
Washington Gas - Virginia	The moratorium on disconnections ended on June 30, 2021. Washington Gas must wait 60 days before making customer disconnections and will not commence charging late fees during this period.	On December 8, 2020, Washington Gas was awarded US$7.7 million under the Virginia CARES Relief Funding Award, to use for customer arrearages. Virginia customers must meet the criteria established by the program to receive the funds. The funds have been fully applied. In August 2021, the Virginia General Assembly appropriated US$120 million of American Rescue Plan Act Funds (ARPA Funds) as direct financial assistance to residential utility customers with arrearages over 60 days as of August 31, 2021. On December 6, 2021, Washington Gas received US$6.9 million of ARPA Funds to be applied to residential customers arrearages.	$0.7 million, and an additional $3.3 million of unrecorded late payment fees.

Utility/ Jurisdiction	Moratoriums	Customer Programs	Regulatory Assets Recorded as at December 31, 2021 ($USD)
SEMCO - Michigan	COVID-related disconnection moratorium ended June 2020.	The MPSC issued an order on February 18, 2021, following a MPSC staff report on energy accessibility and affordability. The order requires the MPSC Staff to establish an Energy Accessibility and Affordability Collaborative to coordinate efforts and find efficiencies between the Energy Waste Reduction (EWR) Low-Income workgroup and the Monthly Energy Assistance Program workgroup. The Collaborative's first meeting occurred on April 8, 2021. MPSC Staff filed an interim report on progress and recommendations on December 17, 2021, which recommended continuation of collaboration between energy waste reduction services and energy assistance to promote energy affordability and accessibility.	None, as bad debt expense is not expected to exceed the level approved in the last rate case proceeding.
ENSTAR - Alaska	COVID-related disconnection moratorium ended November 2020.	ENSTAR received approximately US$1.2 million of CARES Act funding from the Cities of Anchorage, Palmer, Wasilla and Mat-Su Borough, all of which has been applied toward ENSTAR customer accounts.	$0.5 million

Other Regulatory Updates

On July 1, 2021, SEMCO submitted its 2022-2023 EWR Plan, a form of energy efficiency program for its customers, for MPSC approval. SEMCO proposes to spend approximately US$30 million on energy waste reduction over 2022 and 2023 to achieve a combined first year energy savings goal of approximately 10.1 million therms. SEMCO filed its Brief and Reply Brief on December 3, and December 22, 2021, respectively. A Commission order is expected around the second quarter of 2022.

On September 15, 2021, the PSC of DC issued an Order directing Washington Gas to submit a corrective action plan to bring Washington Gas into compliance with the Natural Gas Quality of Service Standards (NGQSS) regarding call response time standards. The Order also stated that Washington Gas shall not disconnect gas customers for non-payment until Washington Gas complies with NGQSS or such time as the PSC of DC otherwise determines. The PSC of DC also found that costs incurred by complying with this Order are not to be included in Washington Gas' COVID-19 regulatory asset. Finally, the Order stated that the PSC of DC found that although it cannot stop Washington Gas from seeking a rate increase, any petition for a rate increase may be held in abeyance either at the request of a party or by the PSC of DC until this performance issue is satisfactorily addressed. Washington Gas filed a corrective action plan with the PSC of DC on September 27, 2021. Washington Gas was in compliance with the call answering and call abandonment NGQSS service metrics in January 2022, and expects to maintain NGQSS levels for these metrics going forward. Pursuant to an Order issued by the PSC of DC on February 10, 2022, Washington Gas will not resume disconnection activities until authorized by the Commission.

On September 30, 2021, the MD OPC filed a motion to establish a corrective action plan and impose civil penalties or, alternatively, to order Washington Gas to show cause why the Commission should not impose civil penalties. The MD OPC's request asserts that Washington Gas has violated Condition 11 of the PSC of MD Order in the Washington Gas Merger proceeding with AltaGas because it has not devoted the resources necessary to ensure continued compliance with all Commission regulations. In particular, the MD OPC asserts that Washington Gas' failure to devote enough resources to customer service has made it impossible for customers to successfully and promptly communicate complaints and disputes. Finally, MD OPC asserts that because Washington Gas cannot receive complaints and disputes, it is unable to satisfactorily resolve them or report them pursuant to its obligations under the Code of Maryland regulations. On October 15, 2021, the PSC of MD issued a show cause order directing Washington Gas to respond to the MD OPC motion and to show cause why the PSC of MD should not impose civil penalties. Additionally, the PSC of MD ordered Washington Gas to include a proposed corrective plan, which addresses the decline in customer service post-merger. On October 22, 2021, Washington Gas filed its reply to the MD OPC's motion. On November 12, 2021, the MD OPC, Montgomery County and Staff filed responses to

Washington Gas' reply. On December 23, 2021, the PSC of MD found that, among other things: (1) Washington Gas violated the Maryland Code of Regulations from 2016 through June 22, 2021; (2) Washington Gas violated Conditions 11 and 11F of the AltaGas Merger Order from June 2018 through June 22, 2021; (3) the Commission will schedule a hearing to address whether and to what extent civil penalties are appropriate; and (4) Washington Gas’ proposed Corrective Action Plan was accepted with modifications. On January 24, 2022, Washington Gas filed for rehearing of two issues from the Order, including the imposition of certain call center performance metrics and the creation of a regulatory liability to account for past costs. Washington Gas has accrued US$350,000 in anticipation of civil penalties related to reporting violations. On February 2, 2022, the Staff of the Maryland Public Service Commission (the MD Staff) filed comments regarding the penalty for Washington Gas' violations of the Code of Maryland Regulations (COMAR) and merger conditions. The MD Staff recommended that the Commission assess a civil penalty against Washington Gas in the range of US$750,000 to US$1.5 million. The Commission held a hearing on February 9, 2022 to address civil penalties and to consider Washington Gas' rehearing request. A decision is pending. The PSC of MD's decision may also address its current directive that Washington Gas shall continue the suspension of dunning letters, disconnections, and late fees until Washington Gas meets required customer service standards for three consecutive months.

On December 17, 2021, Washington Gas filed a proposed amendment for its natural gas conservation and ratemaking efficiency plan (CARE Plan) for the period from May 2022 to April 2025, proposing to continue and expand its portfolio of energy efficiency programs to Virginia customers with a total three-year budget of approximately US$12 million. The Staff Report on findings and recommendation is due March 18, 2022, and Washington Gas comment on the Report is due April 1, 2022. A decision from the SCC of VA is expected in the second quarter of 2022.

Midstream

Operating Statistics

	Three Months Ended December 31		Year Ended December 31	
	2021	2020	**2021**	2020
RIPET export volumes (Bbls/d) (1)	**48,974**	37,782	**50,695**	39,285
Ferndale export volumes (Bbls/d) (1) (2)	**27,635**	33,979	**38,636**	33,979
Total inlet gas processed (Mmcf/d) (1)	**1,534**	1,409	**1,498**	1,357
Extraction ethane volumes (Bbls/d) (1)	**27,000**	30,766	**27,955**	28,018
Extraction NGL volumes (Bbls/d) (1) (3)	**35,734**	34,199	**36,364**	32,206
Fractionation volumes (Bbls/d) (1)	**37,000**	27,026	**30,715**	23,559
Frac spread - realized ($/Bbl) (1) (4)	**9.18**	13.95	**12.15**	14.37
Frac spread - average spot price ($/Bbl) (1) (5)	**35.82**	9.33	**28.91**	5.42
Propane Far East Index (FEI) to Mont Belvieu spread (US$/Bbl) (1) (6)	**12.65**	15.01	**10.14**	11.72
Butane FEI to Mont Belvieu spread (US$/Bbl) (1) (7)	**10.29**	12.84	**10.46**	12.84
Natural gas optimization inventory (Bcf)	**2.0**	39.3	**2.0**	39.3

(1) Average for the period.
(2) Represents propane and butane volumes exported at Ferndale for the period after close of the Petrogas Acquisition on December 15, 2020.
(3) NGL volumes refer to propane, butane, and condensate.
(4) 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.
(5) 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.
(6) Average propane price spread between FEI and Mont Belvieu TET commercial index.
(7) Average butane price spread between FEI and Mont Belvieu TET commercial index for the period beginning December 15, 2020.

Propane volumes exported to Asia at RIPET for the three months ended December 31, 2021 averaged 48,974 Bbls/d compared to 37,782 Bbls/d for the same period in 2020. There were 8 full shipments in the fourth quarter of 2021, compared to 6 shipments and one partially loaded shipment in the same period in 2020. Higher RIPET export volumes were the result of improved logistics and supply volumes in the quarter. Propane and butane export volumes at Ferndale averaged 27,635 Bbls/d, with 5 shipments and one partially loaded shipment to Asia during the three months ended December 31, 2021. Export volumes at Ferndale in the fourth quarter of 2020 represent shipments from the period subsequent to the acquisition of Petrogas, for the period from December 15, 2020 to December 31, 2020.

Propane volumes exported to Asia at RIPET for the year ended December 31, 2021 averaged 50,695 Bbls/d compared to 39,285 Bbls/d for the same period in 2020. There were 32 shipments during the year ended December 31, 2021 compared to 27 shipments in the same period of 2020. Higher RIPET export volumes and shipments were the result of improved logistics and supply volumes compared to 2020. Propane and butane export volumes at Ferndale averaged 38,636 Bbls/d, with 28 shipments to Asia during the year ended December 31, 2021.

Inlet gas processing volumes for the fourth quarter of 2021 increased by 125 Mmcf/d compared to the same quarter in 2020. Higher inlet gas processing volumes in the fourth quarter of 2021 were the result of additional volumes from the Townsend Deep Cut facility, additional volumes from phase 1 of the Nig Creek expansion, which was placed in-service in July 2021, and higher inlet volumes at certain extraction facilities.

Inlet gas processing volumes for the year ended December 31, 2021 increased by 141 Mmcf/d compared to the same period in 2020. Higher inlet gas processing volumes in the year ended December 31, 2021 were a result of additional volumes from the Townsend Deep Cut facility, additional volumes from phase 1 of the Nig Creek expansion, and higher inlet volumes at Gordondale and certain extraction facilities.

Average ethane volumes for the fourth quarter of 2021 decreased by 3,766 Bbls/d, while average NGL production volumes increased by 1,535 Bbls/d compared to the same quarter in 2020. Lower ethane volumes were a result of reinjected ethane volumes at the extraction facilities due to a major customer's scheduled turnaround, the force majeure declared by Nova Chemicals in November 2021, resulting in the curtailment of ethane production for EEEP and JEEP, as well as EEEP's turbo expander not being in commission for most of December. Higher NGL volumes were a result of additional extracted NGL volumes from the Townsend Deep Cut facility and higher inlet volumes at the extraction facilities.

Average ethane volumes for the year ended December 31, 2021 were relatively consistent compared to 2020, while average NGL production volumes increased by 4,158 Bbls/d compared to 2020. Lower ethane volumes were a result of reinjected ethane volumes at the extraction facilities due to a major customer's scheduled turnaround. Higher extracted NGL volumes were a result of additional extracted NGL volumes from the Townsend Deep Cut facility and higher inlet volumes at the extraction facilities.

Fractionation volumes for the fourth quarter of 2021 increased by 9,974 Bbls/d compared to the same quarter in 2020. Higher fractionation volumes were a result of the North Pine expansion, higher inlet and trucked-in volumes at Harmattan, additional liquids volumes from the Townsend Deep Cut facility, and higher fractionation volumes at the Younger facility due to higher inlet.

Fractionation volumes for the year ended December 31, 2021 increased by 7,156 Bbls/d compared to the same period in 2020. Higher fractionation volumes were a result of the North Pine expansion and additional liquids volumes from the Townsend Deep Cut facility.

Natural gas optimization inventory as at December 31, 2021 was 2.0 Bcf (December 31, 2020 - 39.3 Bcf). The decrease was primarily due to the sale of the majority of WGL Midstream's commodity business in April 2021.

Three Months Ended December 31

The Midstream segment reported normalized EBITDA of $102 million in the fourth quarter of 2021, compared to $128 million in the same quarter in 2020. The decrease in normalized EBITDA in the fourth quarter of 2021 was mainly due to cessation of AFUDC related to MVP, the impact of the sale of the majority of WGL Midstream's commodity business, a hedge loss associated with revenue recognized for export cargos loaded at the end of the third quarter at market spot prices, amortization of a contract asset at Gordondale related to a blend and extend contract that was entered into in 2018 with the impact of the lower processing fees being recognized for accounting purposes starting in 2021, and lower realized frac spreads (inclusive of hedges). Factors positively impacting normalized EBITDA in the fourth quarter of 2021 included impacts from the consolidation of Petrogas, higher extracted NGL volumes, higher fractionation and liquids handling revenues and higher processed volumes at the NEBC facilities due to NEBC growth projects placed into service, higher realized propane margins and export volumes at RIPET, and increased earnings from the cogeneration plants at Harmattan due to higher Alberta power prices.

Loss before income taxes in the Midstream segment was $151 million in the fourth quarter of 2021, compared to $36 million in the same quarter in 2020. The increased loss was mainly due to the provision recorded on AltaGas' investment in MVP, the same previously referenced factors impacting normalized EBITDA, the absence of the gain on the re-measurement of AltaGas' previously held equity investment in AIJVLP, and higher unrealized losses on risk management contracts, partially offset by the absence of the provision on Alton recorded in the fourth quarter of 2020, the absence of the dilution loss and other adjustments to equity investments related to the acquisition of Petrogas, and lower depreciation expense as a result of the sale of the majority of WGL Midstream's commodity business.

In the fourth quarter of 2021, the Midstream segment recognized pre-tax provisions on assets of approximately $1 million ($1 million after-tax) primarily related to non-core development stage Midstream projects that are no longer being developed. In addition, in the fourth quarter of 2021, the Midstream segment recognized a pre-tax provision on equity investments of approximately $271 million ($209 million after-tax) related to it's investment in MVP. The provision is a result of continued legal and regulatory challenges associated with the Mountain Valley Pipeline and MVP Southgate projects. In the fourth quarter of 2020, the Midstream segment recognized a gain on its previously held equity investment in AIJVLP of approximately $22 million, as well as a dilution loss and other adjustments to equity investments related to the acquisition of Petrogas of $26 million. In addition, in the fourth quarter of 2020, the Midstream segment recognized pre-tax provisions on assets of approximately $104 million ($79 million after-tax) primarily related to the Alton Natural Gas Storage Project.

Year Ended December 31

The Midstream segment reported normalized EBITDA of $734 million in the year ended December 31, 2021, compared to $473 million in 2020. The increase in normalized EBITDA in the year ended December 31, 2021 was mainly due to impacts from the consolidation of Petrogas, favorable storage and transportation margins and higher storage withdrawals at WGL Midstream in the first quarter of 2021, higher fractionation and liquids handling revenues and higher processed volumes at the NEBC facilities due to NEBC growth projects placed into service, increased earnings from the cogeneration plants at Harmattan due to higher Alberta power prices, and higher export volumes at RIPET. Factors negatively impacting normalized EBITDA in the year ended December 31, 2021 included cessation of AFUDC related to MVP, lower realized merchant margins at RIPET (inclusive of hedges and foreign exchange impacts), amortization of a contract asset at Gordondale related to a blend and extend contract that was entered into in 2018 with the impact of the lower processing fees being recognized for accounting purposes starting in 2021, the impact of the sale of the majority of WGL Midstream's commodity business, and lower realized frac spreads (inclusive of hedges).

Income before income taxes in the Midstream segment was $242 million in the year ended December 31, 2021, compared to $235 million in 2020. The increase was mainly due to the same previously referenced factors impacting normalized EBITDA, the absence of the provision on Alton, higher unrealized gains on risk management contracts, the absence of the dilution loss and other adjustments to equity investments related to the acquisition of Petrogas, the absence of provisions on equity investments related to Constitution which was cancelled in February 2020, and higher gains on the disposition of assets, partially offset by the provision recorded on AltaGas' investment in MVP, the provision on the sale of the majority of WGL Midstream's commodity business, the absence of the gain on the re-measurement of AltaGas' previously held equity investment in AIJVLP, and higher depreciation expense as a result of the consolidation of Petrogas and a full year of NEBC projects in service.

In 2021, the Midstream segment recognized pre-tax gains on dispositions of assets of approximately $6 million related to the sale of the majority of WGL Midstream's commodity business, certain Petrogas propane distribution assets, minor Midstream asset sales, and 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. In addition, in 2021, the Midstream segment recognized pre-tax provisions of approximately $59 million ($44 million after-tax) primarily related to the sale of the majority of WGL Midstream's commodity business as well as the previously mentioned provisions recognized in the fourth quarter of 2021. In 2021, the Midstream segment also recognized the previously mentioned provision on equity investments of $271 million ($209 million after-tax) related to its investment in MVP. In 2020, the Midstream segment recognized a pre-tax gain on the re-measurement of its previously held equity investment in AIJVLP of approximately $22 million and a dilution loss and other adjustments to equity investments related to the acquisition of Petrogas of $42 million. In addition, in 2020, the Midstream segment recognized a pre-tax provision on assets of approximately $106 million related to the previously mentioned provisions recognized in the fourth quarter of 2020 and land parcels located near the Harmattan gas processing plant, as well as a pre-tax provision on equity investments of approximately $7 million related to Constitution which was cancelled in February 2020.

Midstream Hedges

	Three Months Ended December 31		Year Ended December 31	
	2021	2020	**2021**	2020
Frac exposed volumes (Bbls/d)	**9,081**	9,277	**9,887**	8,952
NGL volumes hedged (Bbls/d)	**8,982**	10,068	**9,253**	9,412
Average price of NGL volumes hedged ($/Bbl) (1)	**26**	26	**26**	29
Average export volumes hedged (Bbls/d)	**44,984**	59,630	**47,714**	60,518
Average FEI to North American NGL price spread for volumes hedged (US$/Bbl)	**10**	11	**10**	11

(1) Excludes basis differential

Corporate/Other

Three Months Ended December 31

In the Corporate/Other segment, normalized EBITDA for the fourth quarter of 2021 was $1 million, compared to $5 million in the same quarter in 2020. The decrease was mainly due to lower revenues from design build contracts and the absence of normalized EBITDA from the remaining distributed generation project which transferred to the purchaser in the second quarter of 2021.

Loss before income taxes in the Corporate/Other segment was $75 million in the fourth quarter of 2021, compared to $47 million in the same quarter in 2020. The higher loss was mainly due to the impact of the weaker U.S. dollar, the same previously referenced factors impacting normalized EBITDA, and higher provisions on assets.

In the fourth quarter of 2021, the Corporate/Other segment recognized a pre-tax provision on assets of $5 million related to the Parks at Walter Reed thermal plant in Washington, D.C. which was impaired as the carrying value exceeded future expected cash flows from the asset.

Year Ended December 31

In the Corporate/Other segment, normalized EBITDA for the year ended December 31, 2021 was a loss of $15 million, compared to earnings of $49 million in 2020. The decrease was mainly due to higher expenses related to employee incentive plans as a result of the increasing share price in 2021, the absence of recoveries related to CEWS in 2020, and the impact of the disposition of Pomona in the third quarter of 2020.

Loss before income taxes in the Corporate/Other segment was $334 million in the year ended December 31, 2021, compared to $223 million in 2020. The higher loss was mainly due to the impact of the weaker U.S. dollar, the same previously referenced factors impacting normalized EBITDA, the absence of gains on asset sales, including certain distributed generation projects which were transferred to the purchaser in the first quarter of 2020, and Pomona and Ripon, which were sold in the third quarter of 2020, as well as higher provisions on assets.

In 2021, the Corporate/Other segment recognized a pre-tax loss of approximately $1 million on the last remaining U.S. distributed generation project which was sold in 2019 but transferred to the purchaser during the second quarter of 2021. In addition, in 2021, the Corporate/Other segment recognized the previously mentioned pre-tax provision related to the Parks at Walter Reed thermal plant in Washington, D.C. In 2020, the Corporate/Other segment recognized a pre-tax gain of $9 million on certain U.S. distributed generation projects which were sold in 2019 but transferred to the purchaser in 2020, a pre-tax gain of $5 million on the disposition of Pomona, and a pre-tax gain of $3 million on the disposition of Ripon. In addition, in 2020, the Corporate/Other segment recognized a pre-tax provision of approximately $3 million related to certain U.S. distributed generation projects which had not yet transferred to the purchaser.

Net invested Capital

Net invested capital is a non-GAAP financial measure. Please refer to the *Non-GAAP Financial Measures* section of this MD&A for further discussion.

								Three Months Ended December 31, 2021
($ millions)		**Utilities**		**Midstream**		**Corporate/ Other**		**Total**
Invested capital:								
Property, plant and equipment [1]	**$**	**234**	**$**	**11**	**$**	**2**	**$**	**247**
Intangible assets		**1**		**1**		**1**		**3**
Long-term investments		**—**		**3**		**—**		**3**
Invested capital	**$**	**235**	**$**	**15**	**$**	**3**	**$**	**253**
Disposals:								
Asset dispositions		**—**		**(1)**		**—**		**(1)**
Net invested capital	**$**	**235**	**$**	**14**	**$**	**3**	**$**	**252**

(1) In prior periods, invested capital did not include adjustments for the cost of removal of utility assets; however, beginning in the fourth quarter of 2021, Management has adjusted for these costs to better align with the investing section of the Consolidated Statements of Cash Flows. Comparative periods have been restated to reflect this change.

								Three Months Ended December 31, 2020
($ millions)		Utilities		Midstream		Corporate/ Other		Total
Invested capital:								
Property, plant and equipment [1]	$	227	$	50	$	2	$	279
Intangible assets		1		1		1		3
Business acquisition		—		715		—		715
Long-term investments		—		76		—		76
Contributions from non-controlling interest		—		(2)		—		(2)
Invested capital and net invested capital	$	228	$	840	$	3	$	1,071

(1) In prior periods, invested capital did not include adjustments for the cost of removal of utility assets; however, beginning in the fourth quarter of 2021, Management has adjusted for these costs to better align with the investing section of the Consolidated Statements of Cash Flows. Comparative periods have been restated to reflect this change.

During the fourth quarter of 2021, AltaGas' invested capital was $253 million, compared to $1,071 million in the same quarter in 2020. The decrease in invested capital was primarily due to the absence of cash paid for the Petrogas Acquisition in 2020, lower contributions to long-term investments due the absence of a loan made to an affiliate in the fourth quarter of 2020, and lower additions to property, plant and equipment.

The decrease in additions to property, plant and equipment in the fourth quarter of 2021 was mainly due to lower spend on the Nig Creek expansion and the absence of the Younger facility turnaround costs incurred in the fourth quarter of 2020.

The invested capital in the fourth quarter of 2021 included maintenance capital of $6 million (2020 - $18 million) in the Midstream segment and $1 million (2020 - $nil) related to remaining power assets in the Corporate/Other segment.

Maintenance capital incurred in the fourth quarter of 2021 primarily related to the Townsend, Harmattan, North Pine, EEEP, and Ferndale facilities.

During the fourth quarter of 2021, AltaGas' cash flow from investing activities was an outflow of $241 million, compared to $980 million in the same quarter in 2020. 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.

				Year Ended December 31, 2021
($ millions)	**Utilities**	**Midstream**	**Corporate/ Other**	**Total**
Invested capital:				
Property, plant and equipment [1]	**$ 705**	**$ 61**	**$ 9**	**$ 775**
Intangible assets	**2**	**2**	**2**	**6**
Long-term investments	**—**	**11**	**—**	**11**
Contributions from non-controlling interest	**—**	**(1)**	**—**	**(1)**
Other	**—**	**7**	**—**	**7**
Invested capital	**$ 707**	**$ 80**	**$ 11**	**$ 798**
Disposals:				
Asset dispositions	**—**	**(345)**	**(1)**	**(346)**
Equity method investments	**—**	**(3)**	**—**	**(3)**
Net invested capital	**$ 707**	**$ (268)**	**$ 10**	**$ 449**

(1) In prior periods, invested capital did not include adjustments for the cost of removal of utility assets; however, beginning in the fourth quarter of 2021, Management has adjusted for these costs to better align with the investing section of the Consolidated Statements of Cash Flows. Comparative periods have been restated to reflect this change.

				Year Ended December 31, 2020
($ millions)	Utilities	Midstream	Corporate/ Other	Total
Invested capital:				
Property, plant and equipment [1]	$ 703	$ 139	$ 20	$ 862
Intangible assets	3	3	4	10
Long-term investments [2]	—	147	—	147
Business acquisition	—	715	—	715
Contributions from non-controlling interest	—	(7)	—	(7)
Invested capital	$ 706	$ 997	$ 24	$ 1,727
Disposals:				
Asset dispositions	—	(3)	(71)	(74)
Equity method investments	(369)	(7)	—	(376)
Net invested capital	$ 337	$ 987	$ (47)	$ 1,277

(1) In prior periods, invested capital did not include adjustments for the cost of removal of utility assets; however, beginning in the fourth quarter of 2021, Management has adjusted for these costs to better align with the investing section of the Consolidated Statements of Cash Flows. Comparative periods have been restated to reflect this change.

(2) 2020 invested capital has been revised to include the $7 million final payment related to the Constitution pipeline project that was canceled in February 2020, also to better align with the investing section of the Consolidated Statements of Cash Flows.

During the year ended December 31, 2021, AltaGas' invested capital was $798 million, compared to $1.7 billion in 2020. The decrease in invested capital was primarily due to the absence of cash paid for the Petrogas Acquisition in 2020, lower contributions to long-term investments, and lower additions to property, plant and equipment.

The decrease in contributions to long-term investments in the year ended December 31, 2021 was mainly due to the absence of a capital contribution made to AIJVLP related to a cash call in the first quarter of 2020 and the previously mentioned loan made to an affiliate in the fourth quarter of 2020. The decrease in additions to property, plant and equipment in the year ended December 31, 2021 was mainly due to lower construction costs relating to the NEBC projects, most of which were completed in the first half of 2020, and lower maintenance costs at the Blythe facility, partially offset by construction costs for the Nig Creek expansion, capital invested at consolidated Petrogas facilities, and accelerated pipeline replacement and system betterment program spend at Washington Gas and SEMCO. The dispositions in the year ended December 31, 2021 primarily related to proceeds received from the sale of the majority of WGL Midstream's commodity business, certain Petrogas propane distribution assets, and other minor Midstream asset sales. In the year ended December 31, 2020, dispositions primarily related to the remaining proceeds received from the disposition of the U.S. distributed generation assets and the disposition of Pomona and Ripon in the third quarter of 2020. The disposal of equity method investments in the year ended December 31, 2021 related to the 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, while in the year ended December 31, 2020 the disposals of equity method investments related to the disposition of ACI.

The invested capital for the year ended December 31, 2021 included maintenance capital of $13 million (2020 - $22 million) in the Midstream segment and $7 million (2020 - $14 million) related to remaining power assets in the Corporate/Other segment. The decrease in maintenance capital for the Midstream segment was primarily due to lower maintenance capital at the Younger facility, partially offset by maintenance capital at the consolidated Petrogas facilities. The decrease in maintenance capital for the Corporate/Other segment was primarily due to lower maintenance expenditures at the Blythe facility.

During the year ended December 31, 2021, AltaGas' cash flow from investing activities was an outflow of $483 million, compared to $1,211 million in 2020. 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.

Risk Management

Risks Related to COVID-19

AltaGas, with its subsidiaries, activated its pandemic response team early in 2020 to monitor developments related to COVID-19 and to ensure the Corporation was responding swiftly and appropriately. Continuity plans and preparedness measures have been implemented at each of AltaGas' businesses, with safeguarding the well-being of its personnel as the primary concern. To date, AltaGas has been able to respond to the COVID-19 related challenges without materially disrupting its operations and business. As the COVID-19 pandemic persists, AltaGas continues to take proactive steps to effectively prepare for and address the evolving risks and regulatory mandates in the jurisdictions in which it operates, including changing international travel restrictions, potential for higher incidents of colds and influenza in the winter season, vaccination rates and mandates, vaccine effectiveness, and the evolution of COVID-19 variants. While the Company is moving toward reintegration of its workplaces, AltaGas' approach has been, and will continue to be, risk-based and guided by its core values. The health and safety of AltaGas' employees, customers, contractors, and the communities in which it operates is the top priority and is integrated into each aspect of AltaGas' response efforts.

AltaGas has identified the following as potential direct or indirect impacts to its business and operations from the pandemic:

- **COVID-19 variants:** In response to the emergence of COVID-19 variants, certain COVID-19 restrictions have been reimplemented in the jurisdictions in which AltaGas operates and restrictions may continue to loosen and tighten with subsequent threat from COVID-19 variants. As a result, AltaGas was forced to delay its reintegration efforts. Widespread inability of AltaGas' workforce or contractors to perform their duties as a result of pervasive incidence of a COVID-19 variant or inability to comply with applicable mandates on a timely basis would have an adverse impact on AltaGas' ability to continue normal operations; and

- **Return to work:** As AltaGas reintegrates its personnel to its workplace, it may incur additional costs to meet applicable health and safety requirements, which may include adaptations to its workplaces, workforce testing and compliance with applicable vaccine mandates. The occurrence of additional waves of the virus or its variants, or time required to ensure compliance with applicable mandates may require AltaGas to revise or delay such integration plans.

To the extent these risks materialize, the Corporation’s ability to carry out its business plans for 2022 may be adversely impacted. For further discussion of risks related to COVID-19 please refer to AltaGas' Annual Information Form for the year ended December 31, 2021, under the heading "Risk Factors".

Other

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 and foreign exchange rates, as well as to optimize certain owned and managed natural gas assets. 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 December 31, 2021 and December 31, 2020, the fair values of the Corporation’s derivatives were as follows:

($ millions)		**December 31, 2021**		December 31, 2020
Natural gas	**$**	**(91)**	$	(69)
Energy exports		**15**		(31)
NGL frac spread		**(19)**		(6)
Power		**(26)**		(29)
Crude oil and NGLs		**(8)**		1
Foreign exchange		**—**		23
Net derivative liability	**$**	**(129)**	$	(111)

Summary of Risk Management Contracts

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.

Commodity Price Contracts

The Corporation executes gas, power, LPG, crude oil, ocean freight, and other physical and financial commodity contracts to serve its customers as well as manage and optimize its asset portfolio. A portion of these physical contracts are not recorded at fair value because they are either: 1) designated as “normal purchases and normal sales”; 2) do not qualify as derivative instruments due to the significance of their notional amount relative to the applicable liquid markets; or 3) are weather derivatives, which are not exchanged or traded and the underlying variables relate to a climactic, geological, or other physical variable. The fair value of commodity contracts that qualify as derivatives was calculated using estimated forward prices based on published sources for the relevant period. AltaGas has not elected hedge accounting for any of its derivative contracts currently in place. For AltaGas’ Midstream segment, changes in the fair value of these derivative contracts are recorded in the Consolidated Statements of Income in the period in which the change occurs. For the Utilities segment, changes in the fair value of derivative instruments recoverable or refundable to customers are recorded to regulatory assets or regulatory liabilities on the Consolidated Balance Sheets, while changes in the fair value of derivative instruments not affected by rate regulation are recorded in the Consolidated Statements of Income in the period in which the change occurs. The Midstream segment also executes fixed-for-floating NGL frac spread swaps to manage exposure to frac spreads as the financial results of several extraction plants are affected by fluctuations in NGL frac spreads.

- The average indicative spot NGL frac spread for the year ended December 31, 2021 was approximately $29/Bbl (2020 – $5/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 year ended December 31, 2021 was approximately $12/Bbl inclusive of basis differentials (2020 - $14/Bbl).
- At RIPET and Ferndale, NGL price margins are protected through AltaGas' comprehensive hedging programs. AltaGas is well hedged for 2022 with approximately 74 percent of its 2022 expected frac exposed volumes hedged at approximately $33/Bbl, prior to transportation costs. In addition, approximately 44 percent of AltaGas' 2022 expected export volumes are either tolled or financially hedged with an average FEI to North American financial hedge price of approximately US$13/Bbl for non-tolled propane and butane volumes. AltaGas plans to manage the export facilities such that a growing portion of annual capacity will be underpinned by tolling arrangements, and expects to reach this objective over the next several years.

Additionally, AltaGas uses physical and financial derivatives for the purchase and sale of natural gas in order to optimize owned storage and transportation capacity as well as manage transportation and storage assets on behalf of third parties.

The Utilities segment enters into hedging contracts and other contracts that may qualify as derivative instruments related to the purchase of natural gas to manage price risk for its ratepayers. Additionally, Washington Gas executes commodity-related physical and financial contracts in the form of forward, futures, and option contracts as part of an asset optimization program. Under this program, Washington Gas realizes value from its long-term natural gas transportation and storage capacity resources when they are not being fully used to serve utility customers. Additionally, to serve retail customers, AltaGas enters into both physical and financial contracts for the purchase and sale of electricity and natural gas.

The Corporate/Other segment has various fixed-for-floating power purchase and sale contracts in the Alberta market, which are expected to be settled over the next two years.

Foreign Exchange Contracts

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 other comprehensive income 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 and/or preferred shares outstanding. AltaGas may also enter into foreign exchange forward derivatives to manage the risk of fluctuating cash flows due to variations in foreign exchange rates.

- As at December 31, 2021, Management has designated US$122 million of outstanding loans to hedge against the currency translation effect of its foreign investments (December 31, 2020 - $nil).
- For the year ended December 31, 2021, no after-tax unrealized gains or losses were recorded related to the translation of debt in other comprehensive income (2020 - after-tax unrealized loss of $9 million).

The following foreign exchange forward contracts are outstanding as at December 31, 2021:

Foreign exchange forward contract	Notional Amount *(US$ millions)*	Duration	Weighted average foreign exchange rate	Fair Value
Foreign exchange swaps (purchases)	US$10	Less than one year	1.2640	Less than $1 million

The following foreign exchange forward contracts were outstanding as at December 31, 2020:

Foreign exchange forward contract	Notional Amount *(US$ millions)*	Duration	Weighted average foreign exchange rate		Fair Value *(millions)*
Forward USD sales	US$29	Less than one year	1.3591	$	3
Forward USD purchases	US$356	Less than one year	1.2824	$	(3)
Foreign exchange swaps (sales)	US$410	Less than one year	1.3322	$	23

For the year ended December 31, 2021, AltaGas recorded an after-tax realized gain of $19 million on all foreign exchange forward contracts (2020 - after-tax realized gain of $1 million).

Interest Rate Contracts

AltaGas is exposed to interest rate risk as changes in interest rates may impact future cash flows and the fair value of its financial instruments. The Corporation manages its interest rate risk by holding a mix of both fixed and floating interest rate debt.

From time to time, AltaGas may concurrently draw on its credit facility in U.S. dollars and enter into cross currency basis swaps whereby, on final settlement, AltaGas receives U.S. dollars from the counterparty and pays Canadian dollars to the counterparty.

Weather 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 year ended December 31, 2021, a pre-tax loss of less than $1 million (2020 - pre-tax loss of $3 million) was 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:

	Three Months Ended December 31				Year Ended December 31			
($ millions)		**2021**		2020		**2021**		2020
Natural gas	**$**	**(54)**	$	30	**$**	**6**	$	32
Energy exports		**19**		(29)		**38**		10
Crude oil and NGLs		**17**		4		**1**		4
NGL frac spread		**29**		(13)		**(13)**		(5)
Power		**(42)**		(11)		**9**		(15)
Foreign exchange		**(2)**		(5)		**(23)**		(5)
	$	**(33)**	$	(24)	**$**	**18**	$	21

Please refer to Note 23 of the 2021 Annual Consolidated Financial Statements for further details regarding AltaGas' risk management activities.

Corporation Risks

AltaGas manages its exposure to risks using the strategies outlined in the following table:

Risks	Strategies and Organizational Capability to Mitigate Risks
COVID-19	• Activation of pandemic response team to monitor developments related to COVID-19 and its variants • Implement continuity plans and preparedness measures to ensure safe and reliable operations • Monitor and implement compliance with regulatory requirements in all jurisdictions • Recovery mechanisms in place to track COVID related incremental costs in the Utilities segment • A phased approach to return to work is being managed in keeping with requirements in each jurisdiction with oversight by EHS and senior leadership • Designed and delivered tools and information to support workforce resilience through pandemic
Operations	• Ensure appropriate policies, procedures, and systems are in place and internal controls are operating efficiently • Programs to manage pipeline system integrity including accelerated replacement of aging pipeline and infrastructure based on risk mitigation • Contractual provisions often provide for recovery of operating costs • Centralized procurement strategy to reduce costs • Maintain control over operational decisions, operating costs, and capital expenditures by operating certain jointly-owned facilities • Maintain standard operating practices, assess and document employee competency, and maintain formal inspection, maintenance, environmental, health, and safety programs • Carry property and business interruption insurance • Fixed price operating and maintenance contracts with equipment manufacturers • Hedging strategy used to balance price and operating risk
Health and Safety	• Strong process safety management systems • Pipeline and asset integrity programs in place • Accelerated replacement of mature pipeline infrastructure • Preventative and remedial measures to address leak rates within Washington Gas' distribution system • Continuous process improvement strategy employed • Comprehensive Environmental, Health and Safety management system • Purchase and maintain general liability and business interruption insurance
Adequate natural gas supply and storage capacity to meet customer demand	• Maintain diverse capacity portfolio of firm transportation, storage, and peaking services across different transmission lines for supply flexibility • Capacity reserve portfolio maintained for maximum forecasted load under extreme conditions plus a reserve margin approved by regulators
Long-term natural gas volume declines	• Long-term contracts such as take-or-pay, area of mutual interest, geographic franchise with economic out • Increase market share by expanding existing facilities or acquiring or constructing new facilities in productive resource play regions • Increase geographic and customer diversity to reduce exposure to any one individual customer or area of the WCSB • Strategically locate facilities to provide secure access to gas supply • Capitalize on integrated aspects of AltaGas' business to increase volumes through its processing facilities

Risks	Strategies and Organizational Capability to Mitigate Risks
Commodity price	• Contracting terms and processing, storage, and transportation fees independent of commodity prices through fee-for-service, take-or-pay, fixed-fee, or cost-of-service provisions • Hedging strategy to reduce exposure to commodity prices and earnings volatility established by senior management and monitored by the Risk Management Committee • Regulatory recovery mechanisms for gas purchases to serve utility customers • Matching natural gas and electricity purchase obligations with sales commitments in terms of volume and pricing • AltaGas' Commodity Risk Policy approved by the Board of Directors prohibits transactions for speculative purposes • Employ strong systems and processes for monitoring and reporting compliance with the Commodity Risk Policy • In-depth knowledge and experience of transportation systems, natural gas, NGL, LPG, and power markets where AltaGas operates • Direct marketing to end-use commercial and industrial customers
Information security	• Strong identity and access management controls • Improved information management and control of electronic and physical information, in accordance with data classification, data handling, privacy regulations, and data retention requirements • Ongoing cybersecurity communication and phishing tests, including targeted training to higher risk teams and individuals • Implementation of new information security standards and policies • Procedures to ensure regulatory compliance • Enhanced penetration and vulnerability testing • Incident response protocols
Environment and Climate-related	• Measure and monitor emissions, and seek new technologies to reduce greenhouse gas (GHG) emissions from operations • Programs in place to reduce fugitive methane emissions • Projects designed to limit impacts throughout operations, monitor land, air, and water quality, where appropriate
Regulatory and Stakeholder	• Strong working relationships with regulatory authorities • Regulatory and commercial personnel monitor and manage regulatory issues • Development of consistent framework for community consultation • Safe Digging campaign, emergency preparedness and 24/7 Gas Control and dispatch to protect utility customers and public • Utilities seek rate recovery through rate cases with regulatory commissions and agencies
Legislative	• Ongoing identification of public policy issues to determine risks to the Corporation • Development of advocacy strategies to address risks • Where appropriate, engagement in advocacy at the state/provincial and federal level including participation with trade associations
Liquidity	• Forecast cash flow on a continuous basis to maintain adequate cash balances to fund financial obligations as they come due and to support business operations • Maintain financial flexibility and access to multiple credit facilities and continually monitor covenant compliance • Execute financing plans and strategies to maintain and improve credit ratings to minimize financing costs and support ready access to capital markets
Foreign exchange	• Issue a portion of long-term debt in U.S. dollars which hedges the Corporation’s net investment in U.S. subsidiaries • Employ hedging practices when appropriate, such as entering foreign exchange forward contracts
Interest rates	• Optimize financing plans to maintain and improve credit ratings to minimize interest costs • Monitor and proactively manage the Corporation’s debt maturity profile • Employ hedging practices such as entering into interest rate swaps • Monitor and manage the mix of fixed versus floating rate debt exposures
Credit ratings	• Maintain open dialogue with credit rating agencies and request feedback to understand any potential implications to the Corporation’s credit rating

Risks	Strategies and Organizational Capability to Mitigate Risks
Construction	• Major projects group manages and monitors significant construction projects • Strong in-house project control and management framework • Appropriate internal management structure and processes • Engage specialists in designing and building major projects • Contractual arrangements to mitigate cost and schedule risks
Counterparty	• Strong credit policies and procedures • Continuous review of counterparty creditworthiness • Establish credit thresholds using appropriate credit metrics • Closely monitor exposures and impact of price shocks on liquidity • Build a diverse customer and supplier base • Active accounts receivable monitoring and collections processes in place • Credit terms, netting arrangements, and margining provisions included in contractual agreements
Weather	• Anticipated volumes for SEMCO Gas and ENSTAR are determined based on the 15-year and 10-year rolling average for weather, respectively • In Maryland and Virginia, Washington Gas has in place regulatory mechanisms and rate designs that eliminate deviations in customer usage caused by variations in weather from normal levels • Use of weather derivative instruments by WGL Energy Services
Labor relations	• Initiatives focused on talent development, employee engagement, and diversity and inclusion among workforce • Positive employee relations to retain existing talent and maintain strong relations with labor unions
Litigation	• Proactive management of lawsuits and other claims • Continuous monitoring of defense and settlement costs of lawsuits and claims • Experienced in-house legal department • Use of expert third parties when needed
Natural disasters and catastrophic events	• Risks factored into capital investment, project design, logistics planning of supply chains, emergency response planning, and optimizing the way products are handled and moved • Maintain a comprehensive insurance program that covers losses from natural disasters and catastrophic events such as fires, earthquakes, explosions, floods, tornados, and other similar occurrences. This program provides a risk transfer mechanism that facilitates timely recovery from losses and mitigates financial impact
Government trade policy	• Supply chain personnel monitor potential impacts of government trade policy and tariffs on costs for goods used in the normal course of business
Non-controlling interest in pipeline investments	• Invest in pipeline projects where the developer/builder/operator of the projects are experienced companies with a history of successful project completion • Engage specialists in reviewing project assumptions • Structure investment agreements to provide mitigation for cost overruns • Ensure the structure of the project governance requires timely information flow regarding project status • In-house regulatory affairs and public policy resources to validate the information from the developer/builder/operator • Appropriate internal management structure and processes
Volume of power generated	• PPA for the Blythe facility includes specified target availability levels and pay fixed capacity payments upon achieving target availability, and as a result, volumes of power sold have a minimal impact on the Corporation
Political uncertainty, civil unrest, terrorist attacks, military activity	• Monitor changes in law, political climate, other threats • Operational procedures in place including physical security, emergency response • Ongoing communication by management with employees in all operational areas
Inflationary pressures on labor, materials and equipment	• Monitor potential impacts of inflation which may negatively impact levels of demand for AltaGas' services and cost of inputs, and could, accordingly, have a material adverse effect on AltaGas' business, financial condition, and results of operations

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 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.

				Year Ended December 31
($ millions)		**2021**		2020
Cash from operations	**$**	**738**	$	773
Investing activities		**(483)**		(1,211)
Financing activities		**(245)**		392
Increase (decrease) in cash, cash equivalents, and restricted cash	**$**	**10**	$	(46)

Cash From Operations

Cash from operations decreased by $35 million for the year ended December 31, 2021 compared to 2020, primarily due to unfavorable variances in the net change in operating assets and liabilities and decreased distributions from equity investments, partly offset higher net income after taxes (after adjusting for non-cash items). The majority of the variance in net change in operating assets and liabilities was due to lower cash flow from accounts receivable and inventory due to fluctuations in commodity prices and sales volumes, partially offset by increased cash flows from accounts payable and accrued liabilities driven by fluctuations in volumes and prices and increased cash flows from regulatory assets and liabilities.

Working Capital

($ millions, except working capital ratio)		**December 31, 2021**		December 31, 2020
Current assets	**$**	**2,624**	$	2,497
Current liabilities		**2,657**		2,607
Working deficiency	**$**	**(33)**	$	(110)
Working capital ratio (1)		**0.99**		0.96

(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 inventory, and decreases in short-term debt and accounts payable and accrued liabilities, partially offset by increases in the current portion of long-term debt, and decreases in prepaid expenses and other assets and accounts receivable. AltaGas' working capital will fluctuate in the normal course of business. The working capital deficiency is expected to be funded using cash flow from operations and available credit facilities as required.

Investing Activities

Cash used in investing activities for the year ended December 31, 2021 was $483 million, compared to $1.2 billion in 2020. Investing activities for the year ended December 31, 2021 primarily included expenditures of approximately $814 million for property, plant, and equipment and intangible assets, approximately $11 million of contributions to equity investments, and other changes in investing activities of $7 million, partially offset by proceeds of $3 million received from an escrow account related to the 2019 disposition of AltaGas' investment in Meade and proceeds of $346 million from the disposition of assets (net of transaction costs). Investing activities for the year ended December 31, 2020 included the cash payment, net cash acquired, of $675 million for the Petrogas Acquisition, expenditures of approximately $843 million for property, plant, and equipment and intangible assets, $75 million related to the change in loan to an affiliate, and approximately $72 million of contributions of equity investments, which were partially offset by proceeds of $4 million from the sale of investments in publicly-traded entities, $376 million from the disposition of equity investments (primarily for the disposition of ACI), and proceeds of $74 million from the disposition of assets (net of transaction costs).

Financing Activities

Cash used in financing activities for the year ended December 31, 2021 was $245 million, compared to cash from financing activities of $392 million in 2020. Financing activities for the year ended December 31, 2021 were primarily comprised of net repayments of short-term debt and repayments of long-term debt of $89 million, net repayments under credit facilities of $229 million, dividends of $356 million, and distributions to non-controlling interests of $32 million, partially offset by debt issuances of $446 million, net proceeds from shares issued on the exercise of share options of $14 million, and contributions from non-controlling interests of $1 million. Financing activities for the year ended December 31, 2020 were primarily comprised of net repayments of short-term debt and repayments of long-term debt of $1.2 billion, dividends of $334 million, $200 million for the redemption of Series I Preferred Shares, and distributions to non-controlling interests of $28 million, partially offset by debt issuances of $2.0 billion, net issuances under credit facilities of $191 million, contributions from non-controlling interests of $7 million, and net proceeds from shares issued on the exercise of share options of $1 million. Total dividends paid to common and preferred shareholders of AltaGas for the year ended December 31, 2021 were $356 million (2020 - $334 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) 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.

($ millions)		December 31, 2021		December 31, 2020
Short-term debt [1]	$	161	$	236
Current portion of long-term debt [2]		511		360
Long-term debt [3]		7,684		7,626
Total debt		8,356		8,222
Less: cash and cash equivalents		(63)		(32)
Net debt	$	8,293	$	8,190
Shareholders' equity		6,949		7,041
Non-controlling interests		652		620
Total capitalization	$	15,894	$	15,851
Net debt-to-total capitalization (%)		52		52

(1) For the purposes of the net debt calculation, short-term debt excludes third-party project financing obtained on behalf of the United States federal government to provide funds for the construction of certain energy management services projects. As this debt was obtained on behalf of the U.S. government, AltaGas would only need to repay in the event that the project is not completed or accepted by the government. See Note 15 of the 2021 Annual Consolidated Financial Statements for additional details. At December 31, 2021, the project financing balance excluded from short-term debt in the above table was $8 million (December 31, 2020 - $20 million).

(2) Net of debt issuance costs of $1 million as at December 31, 2021 (December 31, 2020 - Less than $1 million).

(3) Net of debt issuance costs of $43 million as at December 31, 2021 (December 31, 2020 - $43 million).

As at December 31, 2021, AltaGas' total debt primarily consisted of outstanding medium-term notes (MTNs) of $4.3 billion (December 31, 2020 - $4.0 billion), WGL and Washington Gas long-term debt of $2.4 billion (December 31, 2020 - $2.1 billion), reflecting fair value adjustments on acquisition, SEMCO long-term debt of $633 million (December 31, 2020 - $641 million), $495 million drawn under the bank credit facilities (December 31, 2020 - $934 million) and short-term debt of $169 million (December 31, 2020 - $256 million). In addition, AltaGas had $245 million of letters of credit outstanding (December 31, 2020 - $230 million).

As at December 31, 2021, AltaGas' total market capitalization was approximately $7.6 billion based on approximately 280 million common shares outstanding and a closing trading price on December 31, 2021 of $27.16 per common share.

AltaGas' earnings interest coverage for the rolling twelve months ended December 31, 2021 was 2.0 times (twelve months ended December 31, 2020 – 2.8 times).

Credit Facilities *($ millions)*		Borrowing capacity		**Drawn at December 31, 2021**		Drawn at December 31, 2020
AltaGas demand credit facilities (1) (2)	$	70	**$**	**34**	$	—
AltaGas revolving credit facilities (1) (2) (3)		2,300		**375**		802
SEMCO Energy US$150 million credit facilities (1) (2)		190		**120**		80
WGL US$300 million revolving credit facility (1) (2) (4) (5)		380		**342**		132
Washington Gas US$450 million revolving credit facility (1) (2) (4)		571		**288**		363
Petrogas revolving credit facilities (6)		200		**—**		51
Petrogas demand credit facilities		25		**—**		6
	$	3,736	**$**	**1,159**	$	1,434

(1) Amount drawn at December 31, 2021 converted at the month-end rate of 1 U.S. dollar = 1.2678 Canadian dollar (December 31, 2020 - 1 U.S. dollar = 1.2732 Canadian dollar).

(2) All US$ borrowing capacity was converted at the December 31, 2021 U.S./Canadian dollar month-end exchange rate.

(3) During the second quarter of 2021, AltaGas closed an amendment that caused all committed credit facilities in Canada to be consolidated into a $2.3 billion facility. The facility has a $2 billion five-year extendable committed revolving tranche and a $300 million two-year extendable side car liquidity revolving facility.

(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.

(5) During the second quarter of 2021, WGL extended its credit facility by two years and increased the size of the facility to US$300 million. The amended facility matures in July 2024.

(6) During the third quarter of 2021, AltaGas closed an amendment that caused all committed Petrogas credit facilities to be consolidated into a four-year $200 million facility.

In addition to the facilities listed above, AltaGas has demand Letter of Credit facilities of $467 million. At December 31, 2021, there were letters of credit for $245 million (December 31, 2020 - $229 million) issued on these facilities and an additional less than $1 million (December 31, 2020 - $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. As at December 31, 2021, commercial paper outstanding totaled $630 million for WGL and Washington Gas (December 31, 2020 – $495 million).

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 December 31, 2021 and December 31, 2020.

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

Ratios	Debt covenant requirements	**As at December 31, 2021**
Bank debt-to-capitalization (1) (2)	not greater than 65%	less than 50%
Bank EBITDA-to-interest expense (1) (2)	not less than 2.5x	greater than 4.5x
Bank debt-to-capitalization (SEMCO) (2) (3)	not greater than 60%	less than 45%
Bank EBITDA-to-interest expense (SEMCO) (2) (3)	not less than 2.25x	greater than 10.5x
Bank debt-to-capitalization (WGL) (2) (4)	not greater than 65%	less than 46%
Bank debt-to-capitalization (Washington Gas) (2) (4)	not greater than 65%	less than 49%
Net debt-to-EBITDA (Petrogas) (2) (5)	not greater than 4.00x	less than 0.5x
Net Senior debt-to-EBITDA (Petrogas) (2) (5)	not greater than 3.00x	less than 0.1x
Interest Coverage (Petrogas) (2) (5)	not less than 3.00x	greater than 21.0x

(1) Calculated in accordance with the Corporation's $2.3 billion credit facility agreement, which is available on SEDAR at www.sedar.com. 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.

(5) Calculated in accordance with the amended Petrogas credit facility agreement.

On February 22, 2021, a $2.5 billion base shelf prospectus for the issuance of certain types of future public debt and/or equity issuances was filed to replace the base shelf prospectus dated September 25, 2019. This enables AltaGas to access the Canadian capital markets on a timely basis during the 25-month period that the base shelf prospectus remains effective. As at December 31, 2021, approximately $2.0 billion was available under the base shelf prospectus.

On February 22, 2021, AltaGas filed a US$2.0 billion short form base shelf prospectus in both Alberta and the U.S to replace the US$2.0 billion short form base prospectus filed on January 21, 2020. This will enable AltaGas to access the U.S. capital markets during the 25-month period that the base shelf prospectus remains effective. As at December 31, 2021, US$2.0 billion was available under the base shelf prospectus.

Contractual Obligations

December 31, 2021					
($ millions)	**Total**	Less than 1 year	1 - 3 years	4 - 5 years	After 5 years
Short-term debt	**$ 169**	$ 169	$ —	$ —	$ —
Long-term debt (1)	**8,145**	506	1,356	1,775	4,508
Operating leases (2)	**385**	92	126	77	90
Purchase obligations	**13,284**	2,501	3,470	2,494	4,819
Capital project commitments	**3**	3	—	—	—
Pension plan and retiree benefits (3)	**12**	12	—	—	—
Merger commitments (4)	**9**	2	4	2	1
Environmental commitments	**18**	13	3	2	—
Post-acquisition contingent payments (5)	**16**	16	—	—	—
Other liabilities (6)	**43**	43	—	—	—
Total contractual obligations (7)	**$ 22,084**	$ 3,357	$ 4,959	$ 4,350	$ 9,418

(1) Excludes deferred financing costs, discounts, finance lease liabilities, and the fair value adjustment on the WGL Acquisition.
(2) Payments are presented on an undiscounted cash basis.
(3) Assumes only required payments will be made into the pension plans in 2022. Contributions are made in accordance with independent actuarial valuations.
(4) Relates to merger commitments arising from the WGL Acquisition. Represents the estimated future payments of merger commitments that have been accrued but not paid. As at December 31, 2021, the cumulative amount of merger commitments that have been expensed but not yet paid is approximately US$7 million. Additionally, there are a number of operational commitments, including the funding of leak mitigation and reducing leak backlogs, the funding of damage prevention efforts, developing projects to extend natural gas service, maintaining pre-merger quality of service standards including odor call response times, increasing supplier diversity, achieving synergy savings benefits, as well as reporting and tracking related to all the commitments, and developing 15 megawatts of either electric grid energy storage or Tier 1 renewable resources within five years after the merger closed.
(5) Contingent payments of up to $16 million are expected to be paid related to the Petrogas Acquisition.
(6) Excludes non-financial liabilities.
(7) U.S. dollar commitments have been converted to Canadian dollars using the December 31, 2021 exchange rate.

AltaGas expects to fund its obligations through internally-generated cash flow, asset sales, and normal course borrowings on existing committed credit facilities.

Related Party Transactions

In the normal course of business, AltaGas transacts with its subsidiaries, affiliates and joint ventures. Refer to Note 30 of the 2021 Annual Consolidated Financial Statements for the amounts due to or from related parties on the Consolidated Balance Sheets and the classification of revenue, income, and expenses in the Consolidated Statements of Income.

Credit Ratings

The below table summarizes the most recent credit ratings for AltaGas and subsidiaries:

Entity	Rating Agency	Debt Rated	Most Recent Rating	Comments
AltaGas	Standard & Poor's (S&P)	Issuer rating	BBB-	Last reviewed December 20, 2021.
		Senior unsecured	BBB-	Last reviewed December 20, 2021.
		Preferred shares and Junior Subordinated	P-3 / BB	Last reviewed December 20, 2021, Junior Subordinated added on January 5, 2022.
	Fitch Ratings (Fitch)	Issuer	BBB	Affirmed on March 31, 2021.
		Preferred shares and Junior Subordinated	BB+	Affirmed on March 31, 2021, Junior Subordinated added on January 5, 2022.
Washington Gas	S&P	Issuer and unsecured debt	A-	Last reviewed December 20, 2021.
		Commercial paper	A-2	Last reviewed December 20, 2021.
	Fitch	Issuer	A-	Affirmed on April 3, 2020.
WGL	S&P	Issuer	BBB-	Last reviewed December 20, 2021.
		Senior unsecured	BB+	Last reviewed December 20, 2021.
		Commercial paper	A-3	Last reviewed December 20, 2021.
	Fitch	Issuer	BBB	Affirmed on April 3, 2020.
SEMCO	Moody's	Long-term issuer	A3	Raised from Baa1 to A3 on January 22, 2021 with stable outlook.
		Senior secured notes	A1	Raised from A2 to A1 on January 22, 2021 with stable outlook.
	S&P	Long-term issuer	BBB	Last reviewed May 21, 2021.
		Senior secured notes	A-	Last reviewed May 21, 2021.

According to the S&P rating system, an obligor rated BBB has adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories. A P-3 rating by S&P is the third highest of eight categories granted by S&P under its Canadian preferred share rating scale and a P-3 rating directly corresponds with a BB rating under its global preferred rating scale. The Canadian preferred share rating scale is fully determined by the global preferred rating scale and there are no additional analytical criteria associated with the determination of ratings on the Canadian preferred share rating scale. According to the S&P rating system, while securities rated P-3 are regarded as having significant speculative characteristics, they are less vulnerable to non-payment than other speculative issues. However, it faces major ongoing uncertainties or exposure to adverse business, financial, or economic conditions which could lead to the obligor's inadequate capacity to meet its financial commitment on the obligation. The ratings from P-1 to P-5 may be modified by "high" and "low" grades which indicate relative standing within the major rating categories.

According to the Fitch rating system, 'BBB' ratings indicate that expectations of default risk are currently low. The capacity for payment of financial commitments is considered adequate, but adverse business or economic conditions are more likely to impair this capacity. A 'BB' rating by Fitch indicates an elevated vulnerability to default risk, particularly in the event of adverse changes in business or economic conditions over time; however, business or financial flexibility exists that support the servicing of financial commitments.

According to the Moody's rating system, A3 ratings indicate low credit risk. Obligations rated A3 are considered upper-medium grade.

The credit ratings accorded to the securities by the rating agencies are not recommendations to purchase, hold, or sell the securities in as much as such ratings do not comment as to market price or suitability for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant.

Share Information

	As at February 25, 2022
Issued and outstanding	
Common shares	280,443,077
Preferred Shares	
Series A	6,746,679
Series B	1,253,321
Series C	8,000,000
Series E	8,000,000
Series G	6,885,823
Series H	1,114,177
Series K	12,000,000
Issued	
Share options	8,495,435
Share options exercisable	5,648,827

Dividends

On December 3, 2021, AltaGas announced that effective March 31, 2022, common share dividends will be declared and paid on a quarterly basis, instead of monthly. 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 table summarizes AltaGas' dividend declaration history:

Common Share Dividends

Year Ended December 31		
($ per common share)	**2021**	2020
First quarter	**$ 0.249900**	$ 0.240000
Second quarter	**0.249900**	0.240000
Third quarter	**0.249900**	0.240000
Fourth quarter	**0.249900**	0.243300
Total	**$ 0.999600**	$ 0.963300

Series A Preferred Share Dividends

Year Ended December 31				
($ per preferred share)		**2021**		2020
First quarter	**$**	**0.191250**	$	0.211250
Second quarter		**0.191250**		0.211250
Third quarter		**0.191250**		0.211250
Fourth quarter		**0.191250**		0.191250
Total	**$**	**0.765000**	$	0.825000

Series B Preferred Share Dividends

Year Ended December 31				
($ per preferred share)		**2021**		2020
First quarter	**$**	**0.170690**	$	0.268030
Second quarter		**0.170360**		0.267160
Third quarter		**0.174480**		0.183180
Fourth quarter		**0.178830**		0.176520
Total	**$**	**0.694360**	$	0.894890

Series C Preferred Share Dividends

Year Ended December 31				
(US$ per preferred share)		**2021**		2020
First quarter	**$**	**0.330625**	$	0.330625
Second quarter		**0.330625**		0.330625
Third quarter		**0.330625**		0.330625
Fourth quarter		**0.330625**		0.330625
Total	**$**	**1.322500**	$	1.322500

Series E Preferred Share Dividends

Year Ended December 31				
($ per preferred share)		**2021**		2020
First quarter	**$**	**0.337063**	$	0.337063
Second quarter		**0.337063**		0.337063
Third quarter		**0.337063**		0.337063
Fourth quarter		**0.337063**		0.337063
Total	**$**	**1.348252**	$	1.348252

Series G Preferred Share Dividends

Year Ended December 31		
($ per preferred share)	**2021**	2020
First quarter	**$ 0.265125**	$ 0.265125
Second quarter	**0.265125**	0.265125
Third quarter	**0.265125**	0.265125
Fourth quarter	**0.265125**	0.265125
Total	**$ 1.060500**	$ 1.060500

Series H Preferred Share Dividends

Year ended December 31		
($ per preferred share)	**2021**	2020
First quarter	**$ 0.195349**	$ 0.292890
Second quarter	**0.195295**	0.292020
Third quarter	**0.199690**	0.208320
Fourth quarter	**0.204038**	0.201660
Total	**$ 0.794372**	$ 0.994890

Series I Preferred Share Dividends (1)

Year Ended December 31		
($ per preferred share)	**2021**	2020
First quarter	**$ —**	$ 0.328125
Second quarter	**—**	0.328125
Third quarter	**—**	0.328125
Fourth quarter	**—**	0.328125
Total	**$ —**	$ 1.312500

(1) On December 31, 2020, AltaGas redeemed all of its outstanding Series I preferred shares.

Series K Preferred Share Dividends

Year Ended December 31		
($ per preferred share)	**2021**	2020
First quarter	**$ 0.312500**	$ 0.312500
Second quarter	**0.312500**	0.312500
Third quarter	**0.312500**	0.312500
Fourth quarter	**0.312500**	0.312500
Total	**$ 1.250000**	$ 1.250000

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 are contained in the notes to the 2021 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.

Significant estimates and judgments made by Management in the preparation of the Consolidated Financial Statements are outlined below:

Regulatory Assets and Liabilities

SEMCO Gas, ENSTAR and Washington Gas engage in the delivery and sale of natural gas. SEMCO Gas and ENSTAR are regulated by the MPSC and RCA, respectively. Washington Gas is regulated by the PSC of DC in the District of Columbia, the PSC of MD in Maryland, and the SCC of VA in Virginia.

The regulatory agencies exercise statutory authority over matters such as tariffs, rates, construction, operations, financing, returns and certain contracts with customers. In order to recognize the economic effects of the actions and decisions of the regulators, the timing of recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using U.S. GAAP for entities not subject to rate regulation.

Regulatory assets represent future revenues associated with certain costs incurred in the current period or in prior periods that are expected to be recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenue associated with amounts that are expected to be refunded to customers through the rate-setting process.

Asset Impairment

AltaGas reviews long-lived assets, regulatory assets, and intangible assets with indefinite and finite lives whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Recoverability is determined based on an estimate of undiscounted cash flows or other indicators of fair value, and measurement of an impairment loss is determined based on the fair value of the assets. The determination of fair value requires Management to make assumptions about future cash inflows and outflows over the life of an asset. Any changes to the assumptions used for the future cash flow could result in revisions to the evaluation of the recoverability of the long-lived assets or intangible assets and the recognition of an impairment loss in the Consolidated Financial Statements.

AltaGas also tests goodwill for impairment annually or more frequently if events or changes in circumstances indicate that it is more likely than not that the fair value of a reporting unit is less than its carrying value. The Corporation has the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment test. If the quantitative goodwill impairment test is performed, the fair value of the Corporation’s reporting units is compared to the carrying values. If the carrying value of a reporting unit, including allocated goodwill exceeds its fair value, goodwill impairment is measured as the excess of the carrying value amount of the reporting unit’s allocated goodwill over the implied fair value of the goodwill. The fair value used in the quantitative impairment test of goodwill requires estimating future cash flows as well as appropriate discount rates. AltaGas has assessed goodwill for impairment as at December 31, 2021 and determined that no write-down was required.

Asset Retirement Obligations

AltaGas records liabilities relating to asset retirement obligations when there is a legal obligation. In estimating the obligations, Management is required to make assumptions regarding inflation and discount rates, ultimate amounts and timing of settlements, and expected changes in environmental laws and regulation. A change in any of these estimates could have a material impact on AltaGas' Consolidated Financial Statements.

Income Taxes

The Corporation is subject to the provisions of the *Income Tax Act* (Canada) for purposes of determining the amount of income that will be subject to tax in Canada and the *Internal Revenue Code* (U.S.) for the purposes of determining the amount of income that will be subject to tax in the United States. The determination of AltaGas' and its subsidiaries' provision for income taxes requires the application of these complex rules.

Substantial deferred income tax assets and liabilities are recognized in the Consolidated Financial Statements. The recognition of deferred tax assets depends on the assumption that future earnings will be sufficient to realize the deferred benefit. A valuation allowance is recorded against deferred tax assets where all or a portion of that asset is not expected to be realized. The amount of the deferred tax asset or liability recorded is based on Management's best estimate of the timing of the realization of the assets or liabilities.

If Management's interpretation of tax legislation differs from that of tax authorities, or if timing of reversals is not as anticipated, the provision for income taxes could increase or decrease in future periods. See Note 20 of the 2021 Annual Consolidated Financial Statements.

Pension Plans and Post-Retirement Benefits

The determination of pension plan obligations and expense is based on a number of actuarial assumptions. Critical assumptions include the expected long-term rate-of-return on plan assets, the discount rate applied to pension plan obligations, the expected rate of compensation increase, and mortality rates. For post-retirement benefit plans, which provide for certain health care premiums and life insurance benefits for qualifying retired employees and which are not funded, critical assumptions in determining post-retirement obligations and expense are the discount rate and the assumed health care cost trend rates.

Depreciation and Amortization

Depreciation and amortization of property, plant, and equipment and intangible assets are based on Management's judgment of the estimated useful life of the assets. When it is determined that assigned asset lives do not reflect the estimated remaining period of benefit, prospective changes are made to the depreciable lives of those assets. For regulated entities, amortization rates are generally prescribed by the applicable regulatory authority. There are a number of uncertainties inherent in estimating the remaining useful life of certain assets and changes in assumptions could result in material adjustments to the amount of amortization that AltaGas recognizes from period to period.

Loss Contingencies

AltaGas and its subsidiaries are subject to various legal claims and actions arising in the normal course of business. Liabilities for loss contingencies are determined on a case-by-case basis and are accrued for when it is probable that a liability has been incurred and the amount can be reasonably estimated. Significant judgment is required to determine the probability of having incurred the liability and the estimated amount. Estimates are reviewed regularly and updated as new information is received. As at December 31, 2021, no material provisions on loss contingencies have been recorded by the Corporation. However, due to the inherent uncertainty of the litigation process, the resolution of any particular contingencies could have a material adverse effect on the Corporation's results of operations or financial position.

Fair Value of Financial Instruments

Fair value is defined as the amount of consideration that would be agreed upon in an arms-length transaction, other than a forced sale or liquidation, between knowledgeable, willing parties who are under no compulsion to act. The best evidence of fair value is a quoted bid or ask price, as appropriate, in an active market. Fair value based on unadjusted quoted prices in an active market requires minimal judgment by Management. Where bid or ask prices in an active market are not available, Management's judgment on valuation inputs is necessary to determine fair value. AltaGas enters into physical and financial derivative contracts to manage exposure to fluctuations in commodity prices and foreign exchange rates, as well as to optimize certain owned and managed natural gas assets. AltaGas estimates forward prices based on published sources adjusted for factors specific to the asset or liability, including basis and location differentials, discount rates, and currency exchange. The forward curves used to mark these derivative instruments to market are vetted against public sources. Where observable market data is not available, AltaGas uses valuation techniques which require significant judgment by Management. Changes in estimates and assumptions about these inputs could affect the reported fair value.

Adoption of New Accounting Standards

Effective January 1, 2021, AltaGas adopted the following Financial Accounting Standards Board (FASB) issued Accounting Standards Updates (ASU):

- In December 2019, FASB issued ASU No. 2019-12 “Income Taxes: Simplifying the Accounting for Income Taxes". The amendments in this ASU simplify the accounting for income taxes by clarifying certain aspects of current guidance and removing some exceptions to the general principles in ASC 740. The adoption of this ASU did not have a material impact on AltaGas’ consolidated financial statements;

- In January 2020, FASB issued ASU No. 2020-01 “Derivatives and Hedging: Clarifying the Interactions between Topic 321, Topic 323, and Topic 815". The amendments in this ASU clarify the application of the measurement alternative for equity instruments and the measurement of non-derivative forward contracts or purchased call options used to acquire equity securities. The adoption of this ASU did not have a material impact on AltaGas’ consolidated financial statements; and

- In March 2020, FASB issued ASU No. 2020-04 "Reference Rate Reform: Facilitation of the Effects of Reference Rate Reform on Financial Reporting". The amendments in this ASU provide optional expedients and exceptions for applying GAAP to contract modifications and hedging relationships affected by reference rate reform if certain criteria are met. These apply only to contracts, hedging relationships, and other transactions that reference the London Interbank Offered Rate (LIBOR) or another reference rate expected to be discontinued because of reference rate reform. Certain of AltaGas' credit facilities, lessee vehicle finance leases, and carrying charges in certain derivative commodity sale arrangements reference LIBOR. The discontinuation of LIBOR will require these arrangements to be modified to replace LIBOR with an alternative interest rate. As such, AltaGas has made a policy election to adopt the contract modification optional expedients related to these arrangements on January 1, 2021 on a prospective basis. As a result of electing these optional expedients, contract modifications due to LIBOR are not expected to have a material effect on AltaGas' consolidated financial statements. AltaGas will continue to monitor the activities of regulators and financial institutions to transition to an alternative reference rate and continue to review additional arrangements for references to LIBOR. Accordingly, AltaGas may make additional optional elections in the future.

Future Changes in Accounting Principles

In August 2020, FASB issued ASU No. 2020-06 "Debt with Conversion and Other Options and Topic 815-40 - Derivatives and Hedging - Contracts in Entity's Own Equity: Accounting for Convertible Instruments and Contract in an Entity's Own Equity". The amendments in this ASU simplify the accounting for certain financial instruments with characteristics of liabilities and equity, including convertible instruments and contracts in an entity's own equity. The amendments in this ASU are effective for public business entities that meet the definition of a Securities and Exchange Commission (SEC) filer, excluding entities eligible to be smaller reporting companies as defined by the SEC, for fiscal years beginning after December 15, 2021, including interim periods within those fiscal years. For all other entities, the amendments are effective for fiscal years beginning after December 15, 2023, including interim periods within those fiscal years. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated financial statements.

In July 2021, FASB issued ASU No. 2021-05 "Leases (Topic 842): Lessors - Certain Leases with Variable Lease Payments." The amendments in this ASU affect lessors with lease contracts that have variable lease payments that do not depend on a reference index or a rate and would have resulted in the recognition of a selling loss at lease commencement if classified as sales-type or direct financing. The amendments are effective for fiscal years beginning after December 15, 2021, including interim periods within those fiscal years and could either be applied retrospectively to leases that commenced or were modified upon the adoption of ASC 842 or prospectively to new or modified leases. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

In October 2021, FASB issued ASU 2021-08 "Business Combinations (Topic 805): Accounting for Contract Assets and Contract Liabilities from Contracts with Customers". The amendments in this ASU require an entity to recognize and measure contract assets and liabilities acquired in a business combination in accordance with Topic 606. The amendments in this ASU are effective for fiscal years beginning after December 15, 2022 and should be applied prospectively to business combinations occurring on or after the effective date of the amendment. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

In November 2021, FASB issued ASU No. 2021-10 "Government Assistance (Topic 832): Disclosures by Business Entities about Government Assistance". The amendments in this ASU require annual disclosure about transactions with a government entity, including the nature of the transactions, the method applied to account for the government assistance, impacted line items on the financial statements, and significant terms and conditions of the agreement. The amendments in this ASU are effective for fiscal years beginning after December 15, 2021 and could either be applied prospectively to all new transactions with a government that are entered into after the date of initial application or retrospectively to those transactions. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

Off-Balance Sheet Arrangements

AltaGas is not party to any contractual arrangements with unconsolidated entities that have, or are reasonably likely to have, a current or future material effect on the Corporation’s financial performance or financial condition including liquidity and capital resources.

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

Management, including the Chief Executive Officer and Chief Financial Officer, are 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, have 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 have 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 year ended December 31, 2021, there were no changes made to AltaGas' ICFR that materially affected, or are reasonably likely to materially affect, its ICFR or DCP. AltaGas does not believe that process changes adopted in connection with the COVID-19 pandemic have materially affected ICFR.

The Chief Executive Officer and the Chief Financial Officer have evaluated, with the assistance of AltaGas' employees, the effectiveness of AltaGas' DCP and ICFR as at December 31, 2021 and concluded that as at December 31, 2021 AltaGas' DCP and ICFR were effective.

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.

Summary of Consolidated Results for the Eight Most Recent Quarters (1)

($ millions)	**Q4-21**	Q3-21	Q2-21	Q1-21	Q4-20	Q3-20	Q2-20	Q1-20
Total revenue	**3,140**	2,339	2,009	3,085	1,689	969	1,059	1,869
Normalized EBITDA (2)	**341**	244	230	674	392	213	206	499
Net income (loss) applicable to common shares	**(156)**	25	24	337	48	(47)	21	464
($ per share)	**Q4-21**	Q3-21	Q2-21	Q1-21	Q4-20	Q3-20	Q2-20	Q1-20
Net income (loss) per common share								
Basic	**(0.56)**	0.09	0.09	1.21	0.17	(0.17)	0.08	1.66
Diluted	**(0.56)**	0.09	0.09	1.20	0.17	(0.17)	0.08	1.66
Dividends declared	**0.25**	0.25	0.25	0.25	0.24	0.24	0.24	0.24

(1) Amounts may not add due to rounding.

(2) Non-GAAP financial measure. See discussion in the *Non-GAAP Financial Measures* section of this MD&A.

AltaGas' quarter-over-quarter financial results are impacted by seasonality, fluctuations in commodity prices, weather, the U.S./ Canadian 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 seasonally colder weather experienced at several of the utilities in the second and third quarters of 2020;
- The impact of the sale of Pomona and Ripon in the third quarter of 2020;
- The impact of the acquisition of additional equity interest in Petrogas in the fourth quarter of 2020; and
- The impact of the sale of the majority of WGL Midstream's commodity business in the second quarter of 2021.

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, gains or losses on long-term investments, 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, 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 and acquired contingencies of approximately $28 million and $18 million incurred throughout 2021 and 2020, respectively, due to the acquisition of Petrogas and asset sales;
- The impact of the sale of ACI in the first quarter of 2020;
- The impact of the sale of Pomona and Ripon in the third quarter of 2020;
- The impact of the change in accounting principle relating to Washington Gas' net periodic pension and other post-retirement benefit plan costs in the third quarter of 2020;
- The impact of the acquisition of additional equity interest in Petrogas in the fourth quarter of 2020;
- The after-tax provision of approximately $79 million recognized in the fourth quarter of 2020 related to the Alton Natural Gas Storage Project;
- The impact of the sale of the majority of WGL Midstream's commodity business in the second quarter of 2021;
- The after-tax provision of approximately $43 million recognized in 2021 related to the sale of the majority of WGL Midstream's commodity business; and
- The after-tax provision on equity investments of approximately $209 million recognized in the fourth quarter of 2021 related to AltaGas' investment in MVP, which includes the Mountain Valley Pipeline and MVP Southgate projects.

SELECTED ANNUAL FINANCIAL INFORMATION

($ millions, except where noted)	**2021**	2020	2019
Revenue	**10,573**	5,587	5,495
Net income applicable to common shares	**230**	486	769
Net income per common share - basic	**0.82**	1.74	2.78
Net income per common share - diluted	**0.82**	1.74	2.77
Total assets	**21,593**	21,532	19,795
Total long-term liabilities	**11,335**	11,264	9,301
Weighted average number of common shares outstanding *(millions)*	**280**	279	277
Dividends declared per common share *($ per share)*	**0.999600**	0.963300	0.960000
Preferred share dividends declared *($ per share)*			
Series A	**0.765000**	0.825000	0.845000
Series B	**0.694360**	0.894890	1.084641
Series C *(US$)*	**1.322500**	1.322500	1.322500
Series E	**1.348252**	1.348252	1.348252
Series G	**1.060500**	1.060500	1.155750
Series H	**0.794372**	0.994890	0.296040
Series I (1)	**—**	1.312500	1.312500
Series K	**1.250000**	1.250000	1.250000
Washington Gas $4.80 series *(US$)* (2)	**—**	—	2.400000
Washington Gas $4.25 series *(US$)* (2)	**—**	—	2.125000
Washington Gas $5.00 series *(US$)* (2)	**—**	—	2.500000

(1) Series I preferred shares were redeemed on December 31, 2020.

(2) Washington Gas preferred shares were redeemed on December 20, 2019.

MANAGEMENT'S REPORT

The Consolidated Financial Statements of AltaGas Ltd. (AltaGas or the Corporation) and other financial information included in this report are the responsibility of Management. The Consolidated Financial Statements have been prepared by Management in accordance with United States Generally Accepted Accounting Principles (U.S. GAAP) and include amounts that are based on Management’s best estimates and judgments. It is Management's responsibility to ensure that judgments, estimates and accounting principles and methods used in the preparation of financial information are reasonable, appropriate, and applied consistently.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal controls over financial reporting for the Corporation (as defined in Rules 13a-15(f) of the Securities Exchange Act and under National Instrument 52-109).

Management has used the framework established in the 2013 Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) to evaluate the effectiveness of the Corporation's internal control over financial reporting. Based on this evaluation, Management, including the CEO and CFO, has concluded that the Corporation's internal control over financial reporting is effective as at December 31, 2021.

Internal control over financial reporting may not prevent all misstatements due to its inherent limitations. In addition, the evaluation of internal control was made as of a specific date and continued effectiveness in future periods is subject to the risk that controls may become inadequate.

The Board of Directors is responsible for ensuring that Management fulfills its responsibilities for financial reporting and internal controls. The Board is assisted in carrying out its responsibilities principally through its Audit Committee which is composed of independent non-management directors. The Audit Committee meets with Management regularly and meets independently with internal and external auditors and as a group to review any significant accounting, internal controls, and auditing matters in accordance with the terms of the Charter of the Audit Committee, which is set out in the Annual Information Form.

The shareholders have appointed Ernst & Young LLP as independent external auditors to express an opinion as to whether the Consolidated Financial Statements present fairly, in all material respects, the Corporation's consolidated financial position, results of operations, and cash flows in accordance with U.S. GAAP. Ernst & Young LLP is not required under securities law to express an opinion as to the effectiveness of the Corporation's internal control over financial reporting. The report of Ernst & Young LLP outlines the scope of its examination and its opinion on the Consolidated Financial Statements.

(signed) "Randall Crawford"

RANDALL CRAWFORD
President and
Chief Executive Officer of
AltaGas Ltd.

(signed) "James Harbilas"

JAMES HARBILAS
Executive Vice President and
Chief Financial Officer of
AltaGas Ltd.

March 3, 2022

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders of AltaGas Ltd.

Opinion on the Consolidated Financial Statements

We have audited the accompanying balance sheets of AltaGas Ltd. (the “Company”) as of December 31, 2021 and 2020, the related consolidated statements of income, comprehensive income, equity and cash flows for each of the years then ended, and the related notes (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of AltaGas Ltd. as at December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the years then ended, in conformity with United States generally accepted accounting principles.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company‘s management. Our responsibility is to express an opinion on the Company‘s consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the US federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved especially challenging, subjective or complex judgements. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing a separate opinion on the critical audit matters or on the accounts or disclosures to which it relates.

Fair Value Measurement of Level 3 Derivatives

Description of the Matter	As described in Note 23 to the financial statements, AltaGas Ltd. enters into commodity contracts that qualify as derivative instruments and are accounted for under ASC Topic 815, Derivatives and Hedging. The fair value measurements of certain of these contracts are considered Level 3 under the fair value hierarchy as they are determined using significant unobservable inputs. As of December 31, 2021, derivative assets of $69 million and derivative liabilities of $224 million were recorded based on Level 3 fair value measurements. Auditing the fair value measurement of Level 3 derivative instruments was complex given the judgmental nature of the assumptions used as inputs into the valuation models. In particular, the valuation of Level 3 derivative instruments is sensitive to significant unobservable inputs used by the Company such as the assumed natural gas basis prices and implied volatilities of natural gas prices. These unobservable assumptions could be affected by future economic and market conditions.
How We Addressed the Matter in Our Audit	To test the valuation of Level 3 derivative instruments, our audit procedures included, among others, evaluating the valuation methodologies used by the Company and testing significant inputs, assumptions and the mathematical accuracy of the calculations. In certain instances, we independently determined the significant unobservable assumptions described above, calculated the resulting fair values and compared them to the Company's estimates. For a sample of instruments, we obtained forward prices from independent sources, including broker quotes, evaluated the Company's assumptions related to their forward curves and obtained external confirmation of key contract terms from counterparties. We also performed sensitivity analyses using independent sources of market data to evaluate the change in fair value of Level 3 derivative instruments that would result from changes in underlying assumptions.

Valuation of Equity Method Investment in Mountain Valley Pipeline LLC

Description of the Matter

At December 31, 2021, the Company has an investment in the Mountain Valley Pipeline ("MVP") of approximately $447 million. As discussed in Note 2 and 14 to the consolidated financial statements, the Company accounts for its interests in MVP under the equity method because it has the ability to exercise significant influence, but not control, over MVP's operating and financial policies. The Company reviews the carrying value of its investments in unconsolidated entities for impairment whenever events or changes in circumstances indicate that the investment may not be recoverable. When such condition is deemed other than temporary, the Company writes down the carrying value of the investment to its fair value, and an impairment charge is recorded in the Consolidated Statements of Income. As described in Note 14 to the consolidated financial statements, the Company recorded an impairment charge of $271 million at December 31, 2021 on the MVP investment due to continued legal and regulatory challenges. The fair value of the investment in MVP was calculated using a discounted cash flow model, taking into account the cap on the Company's contractual capital contributions, cost of capital, an assessment of the probability that MVP will overcome legal and regulatory challenges, and the potential removal costs should the project not move forward.

Auditing management's measurement of impairment of the equity investment in the MVP was complex due to the significant judgment required to estimate the fair value of the investment. In particular, the fair value estimate of the equity investment in MVP was sensitive to significant assumptions, including the probability that MVP will overcome legal and regulatory challenges and the discount rate.

How We Addressed the Matter in Our Audit

To test the Company's impairment measurement related to its equity investment in MVP, our audit procedures included, among others, testing the completeness and accuracy of the underlying data used in the discounted cash flow model and testing the significant assumptions described above. We involved our valuation specialists to assess the appropriateness of the valuation methodology, including evaluating the discount rate by referencing current industry, economic, and comparable company information. We evaluated the reasonableness of the probability that MVP will overcome legal and regulatory challenges by reviewing information included in analyst and industry reports, internal communications to management and the Board of Directors and other MVP Partners' press releases and regulatory filings.

We have served as AltaGas Ltd. auditor since 1997.

Ernst & Young LLP

Chartered Professional Accountants

Calgary, Canada
March 3, 2022

CONSOLIDATED BALANCE SHEETS

As at December 31		2021		2020
ASSETS				
Current assets				
Cash and cash equivalents *(note 31)*	**$**	**63**	$	32
Accounts receivable *(net of credit losses of $39 million) (notes 10 and 23)*		**1,427**		1,444
Inventory *(note 7)*		**782**		636
Restricted cash holdings from customers *(note 31)*		**3**		3
Regulatory assets *(note 21)*		**48**		46
Risk management assets *(note 23)*		**113**		98
Prepaid expenses and other current assets *(notes 28 and 31)*		**188**		234
Assets held for sale *(note 5)*		**—**		4
		2,624		2,497
Property, plant and equipment *(note 8)*		**11,323**		10,888
Intangible assets *(note 9)*		**171**		539
Operating right-of-use assets *(note 10)*		**311**		372
Goodwill *(note 11)*		**5,153**		5,039
Regulatory assets *(note 21)*		**436**		444
Risk management assets *(note 23)*		**51**		47
Restricted cash holdings from customers *(note 31)*		**—**		2
Prepaid post-retirement benefits *(note 28)*		**674**		572
Long-term investments and other assets *(net of credit losses of $1 million) (notes 12, 28, and 31)*		**227**		245
Investments accounted for by the equity method *(note 14)*		**623**		887
	$	**21,593**	$	21,532
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current liabilities				
Accounts payable and accrued liabilities *(notes 17, 18, 23, and 28)*	**$**	**1,544**	$	1,561
Dividends payable *(note 23)*		**—**		22
Short-term debt *(notes 15 and 23)*		**169**		256
Current portion of long-term debt *(notes 16 and 23)*		**511**		360
Customer deposits		**74**		73
Regulatory liabilities *(note 21)*		**79**		90
Risk management liabilities *(note 23)*		**128**		111
Operating lease liabilities *(note 10)*		**91**		95
Other current liabilities *(note 23)*		**61**		38
Liabilities associated with assets held for sale *(note 5)*		**—**		1
		2,657		2,607
Long-term debt *(notes 16 and 23)*		**7,684**		7,626
Asset retirement obligations *(note 17)*		**429**		379
Unamortized investment tax credits *(note 20)*		**2**		3
Deferred income taxes *(note 20)*		**1,158**		1,118
Regulatory liabilities *(note 21)*		**1,424**		1,381
Risk management liabilities *(note 23)*		**165**		145
Operating lease liabilities *(note 10)*		**253**		304
Other long-term liabilities *(notes 19 and 23)*		**134**		153
Future employee obligations *(note 28)*		**86**		155
	$	**13,992**	$	13,871

As at December 31		2021		2020
Shareholders' equity				
Common shares, no par values, unlimited shares authorized; 2021 - 280.3 million and 2020 - 279.5 million issued and outstanding *(note 25)*	**$**	**6,735**	$	6,723
Preferred shares *(note 25)*		**1,076**		1,077
Contributed surplus		**388**		383
Accumulated deficit		**(1,243)**		(1,192)
Accumulated other comprehensive income (loss) (AOCI) *(note 22)*		**(7)**		50
Total shareholders' equity		**6,949**		7,041
Non-controlling interests		**652**		620
Total equity	**$**	**7,601**	$	7,661
	$	**21,593**	$	21,532

Business acquisition (note 3)
Variable interest entities (note 13)
Commitments, guarantees and contingencies (note 29)
Related party transactions (note 30)
Segmented information (note 32)
Subsequent events (note 33)

See accompanying notes to the Consolidated Financial Statements.

Approved by the Board of Directors of AltaGas Ltd.

(signed) "Randall Crawford"

RANDALL CRAWFORD

Director

(signed) "Robert B. Hodgins"

ROBERT B. HODGINS

Director

CONSOLIDATED STATEMENTS OF INCOME

Year Ended December 31		2021		2020
REVENUE *(note 24)*	**$**	**10,573**	$	5,587
EXPENSES				
Cost of sales, exclusive of items shown separately		**7,708**		3,178
Operating and administrative		**1,476**		1,267
Accretion expenses *(note 17)*		**6**		5
Depreciation and amortization *(notes 8 and 9)*		**422**		414
Provisions on assets *(note 6)*		**64**		109
		9,676		4,973
Income (loss) from equity investments *(note 14)*		**(261)**		49
Other income *(note 27)*		**81**		306
Foreign exchange gains		**4**		4
Interest expense		**(275)**		(274)
Income before income taxes		**446**		699
Income tax expense *(note 20)*				
Current		**59**		1
Deferred		**47**		126
Net income after taxes		**340**		572
Net income applicable to non-controlling interests		**57**		20
Net income applicable to controlling interests		**283**		552
Preferred share dividends		**(53)**		(66)
Net income applicable to common shares	**$**	**230**	$	486
Net income per common share *(note 26)*				
Basic	**$**	**0.82**	$	1.74
Diluted	**$**	**0.82**	$	1.74
Weighted average number of common shares outstanding (millions) *(note 26)*				
Basic		**279.9**		279.4
Diluted		**281.7**		279.7

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year Ended December 31		**2021**		2020
Net income after taxes	**$**	**340**	$	572
Other comprehensive income (loss), net of taxes				
Loss on foreign currency translation		**(61)**		(175)
Unrealized loss on net investment hedge *(note 23)*		**—**		(9)
Actuarial gain (loss) on pension plans and post-retirement benefit (PRB) plans *(note 28)*		**2**		(8)
Reclassification of actuarial gains and prior service credits on defined benefit (DB) and post-retirement benefit plans (PRB) to net income *(note 28)*		**2**		2
Other comprehensive loss from equity investees		**—**		(5)
Total other comprehensive loss (OCI), net of taxes *(note 22)*	**$**	**(57)**	$	(195)
Comprehensive income attributable to controlling interests and non-controlling interests, net of taxes	**$**	**283**	$	377
Comprehensive income attributable to:				
Non-controlling interests	**$**	**56**	$	21
Controlling interests		**227**		356
	$	**283**	$	377

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF EQUITY

Year Ended December 31		2021		2020
Common shares *(note 25)*				
Balance, beginning of year	**$**	**6,723**	$	6,719
Shares issued for cash on exercise of options		**15**		1
Shares issued under DRIP [1]		**—**		6
Deferred taxes on share issuance costs		**(3)**		(3)
Balance, end of year	**$**	**6,735**	$	6,723
Preferred shares *(note 25)*				
Balance, beginning of year	**$**	**1,077**	$	1,277
Redemption of preferred shares		**—**		(200)
Deferred taxes on share issuance costs		**(1)**		—
Balance, end of year	**$**	**1,076**	$	1,077
Contributed surplus				
Balance, beginning of year	**$**	**383**	$	377
Share options expense		**7**		6
Exercise of share options		**(2)**		—
Balance, end of year	**$**	**388**	$	383
Accumulated deficit				
Balance, beginning of year	**$**	**(1,192)**	$	(1,403)
Net income applicable to controlling interests		**283**		552
Common share dividends		**(281)**		(268)
Preferred share dividends		**(53)**		(66)
Adoption of ASU No. 2016-13 *(note 23)*		**—**		(7)
Balance, end of year	**$**	**(1,243)**	$	(1,192)
AOCI *(note 22)*				
Balance, beginning of year	**$**	**50**	$	245
Other comprehensive loss		**(57)**		(195)
Balance, end of year	**$**	**(7)**	$	50
Total shareholders' equity	**$**	**6,949**	$	7,041
Non-controlling interests				
Balance, beginning of year	**$**	**620**	$	154
Net income applicable to non-controlling interests		**57**		20
Foreign currency translation adjustments		**6**		—
Contributions from non-controlling interests to subsidiaries		**1**		7
Distributions by subsidiaries to non-controlling interests		**(32)**		(28)
Acquisition of non-controlling interests through Petrogas Acquisition *(note 3)*		**—**		467
Balance, end of year	**$**	**652**	$	620
Total equity	**$**	**7,601**	$	7,661

(1) Premium Dividend™, Dividend Reinvestment and Optional Cash Purchase Plan (DRIP). The plan was suspended in December 2019, with the December dividend (paid January 2020) being the last dividend payment eligible for reinvestment by participating shareholders under the DRIP.

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31		2021		2020
Cash from (used by) operations				
Net income after taxes	**$**	**340**	$	572
Items not involving cash:				
Depreciation and amortization *(notes 8 and 9)*		**422**		414
Provisions on assets *(note 6)*		**64**		109
Accretion expenses *(note 17)*		**6**		5
Share-based compensation *(note 25)*		**7**		6
Deferred income tax expense *(note 20)*		**47**		126
Gains on sale of assets *(notes 4 and 27)*		**(6)**		(223)
Gain on remeasurement of previously held interest in AIJVLP *(note 3)*		**—**		(22)
Loss (income) from equity investments *(note 14)*		**261**		(49)
Unrealized gains on risk management contracts *(note 23)*		**(18)**		(21)
Amortization of deferred financing costs		**5**		8
Provision for doubtful accounts		**14**		25
Change in pension and other post-retirement benefits *(note 28)*		**(25)**		(11)
Other		**28**		15
Asset retirement obligations settled *(note 17)*		**(10)**		(4)
Distributions from equity investments		**13**		26
Changes in operating assets and liabilities *(note 31)*		**(410)**		(203)
	$	**738**	$	773
Investing activities				
Business acquisitions, net of cash acquired *(note 3)*		**—**		(675)
Capital expenditures - property, plant and equipment		**(805)**		(825)
Capital expenditures - intangible assets		**(9)**		(18)
Contributions to equity investments		**(11)**		(72)
Change in loan to affiliate		**—**		(75)
Proceeds from disposition of equity investments *(note 14)*		**3**		376
Proceeds from sale of investments in publicly-traded entities		**—**		4
Proceeds from disposition of assets, net of transaction costs *(note 4)*		**346**		74
Other changes in investing activities		**(7)**		—
	$	**(483)**	$	(1,211)
Financing activities				
Net repayment of short-term debt		**(78)**		(157)
Issuance of long-term debt, net of debt issuance costs		**446**		1,962
Repayment of long-term debt		**(11)**		(1,056)
Net borrowing (repayment) under credit facilities		**(229)**		191
Dividends - common shares		**(303)**		(268)
Dividends - preferred shares		**(53)**		(66)
Distributions to non-controlling interest		**(32)**		(28)
Contributions from non-controlling interests		**1**		7
Net proceeds from shares issued on exercise of options		**14**		1
Net proceeds from issuance of common shares		**—**		6
Redemption of preferred shares *(note 25)*		**—**		(200)
	$	**(245)**	$	392
Change in cash, cash equivalents, and restricted cash		**10**		(46)
Effect of exchange rate changes on cash, cash equivalents, and restricted cash		**—**		(2)
Cash, cash equivalents, and restricted cash beginning of year		**74**		122
Cash, cash equivalents, and restricted cash end of year *(note 31)*	**$**	**84**	$	74

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 Corporation, 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. (SEMCO); 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, subsidiaries include AltaGas Power Holdings (U.S.) Inc., WGL Energy Systems, Inc. (WGL Energy Systems), and Blythe Energy Inc. (Blythe). SEMCO conducts its Michigan natural gas distribution business under the name SEMCO Energy Gas Company (SEMCO Gas), its Alaska natural gas distribution business under the name ENSTAR Natural Gas Company (ENSTAR) and its 65 percent interest in an Alaska regulated gas storage utility under the name Cook Inlet Natural Gas Storage Alaska LLC (CINGSA).

AltaGas is a leading energy infrastructure company that connects natural gas and NGLs to domestic and global markets. 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 provide safe, reliable, affordable energy to approximately 1.7 million residential and commercial customers. This includes operating four utilities that operate across five major U.S. jurisdictions with an average 2021 rate base of approximately US$4.7 billion The Utilities business also includes storage facilities and contracts for interstate natural gas transportation and storage services, as well as the affiliated retail energy marketing business, which sells natural gas and electricity directly to approximately 0.5 million residential, commercial, and industrial customers located in Maryland, Virginia, Delaware, Pennsylvania, Ohio, and the District of Columbia; and
- Midstream, which is a leading North American platform that connects customers and markets from wellhead to tidewater and beyond. The three pillars of the Midstream business include: 1) global exports, which includes AltaGas' two LPG export terminals; 2) natural gas gathering and extraction; and 3) fractionation and liquids handling. AltaGas' Midstream segment also includes its natural gas and NGL marketing business, domestic logistics, trucking and rail terminals, and liquid storage capability. The addition of Petrogas resulted in revenue of approximately $4.7 billion for the year ended December 31, 2021.

The Corporate/Other segment consists of AltaGas' corporate activities and a small portfolio of gas-fired power generation and distribution assets capable of generating 578 MW of power in California and Colorado.

2. Summary of Significant Accounting Policies

BASIS OF PRESENTATION

These Consolidated Financial Statements have been prepared by Management in accordance with United States Generally Accepted Accounting Principles (U.S. GAAP).

Pursuant to National Instrument 52-107, "Acceptable Accounting Principles and Auditing Standards" (NI 52-107), financial statements of an "SEC issuer" may be prepared in accordance with U.S. GAAP. On February 22, 2021, AltaGas filed a final short form base shelf prospectus in Alberta and a corresponding registration statement on Form F-10 in the United States, by virtue of which AltaGas is required to file reports under section 15(d) of the *Securities Exchange Act of 1934* with the United States Securities and Exchange Commission. As a result, AltaGas is an SEC issuer and is entitled to prepare its financial statements in accordance with U.S. GAAP.

PRINCIPLES OF CONSOLIDATION

These 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.

Hypothetical Liquidation at Book Value (HLBV) methodology is used for AltaGas' investment in Mountain Valley Pipeline (MVP) This methodology is used when the governing structuring agreement over the equity investment results in different liquidation rights and priorities than what is reflected by the underlying ownership interest percentage.

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 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. Key areas where Management has made complex or subjective judgments, when matters are inherently uncertain, include but are not limited to: determining the nature and timing of satisfaction of performance obligations and determining the transaction price and amounts allocated to performance obligations for revenue recognition; depreciation and amortization rates; determination as to whether a contract is or contains a lease; determination of the classification, term, and discount rate for leases; fair value of asset retirement obligations; fair value of property, plant and equipment and goodwill for impairment assessments; fair value of financial instruments; measurement of credit losses; provisions for income taxes; assumptions used to measure employee future benefits; provisions for contingencies; purchase price allocations; and carrying value of regulatory assets and liabilities. Certain estimates are necessary for the regulatory environment in which AltaGas' subsidiaries or affiliates operate, which often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. By their nature, these estimates are subject to measurement uncertainty and may impact the Consolidated Financial Statements of future periods.

SIGNIFICANT ACCOUNTING POLICIES

Rate-Regulated Operations

SEMCO Gas, ENSTAR, Washington Gas, and Hampshire Gas (collectively the Utilities) engage in the delivery, sale, and storage of natural gas. SEMCO Gas and ENSTAR are regulated by the Michigan Public Service Commission (MPSC) and Regulatory Commission of Alaska (RCA), respectively. Washington Gas operates in the District of Columbia, Maryland, and Virginia, and is regulated in those jurisdictions by the Public Service Commission of the District of Columbia (PSC of DC), the Maryland Public Service Commission (PSC of MD), and the Commonwealth of Virginia State Corporation Commission (SCC of VA), respectively. Hampshire is regulated under a cost-of-service tariff by the Federal Energy Regulatory Commission (FERC).

The MPSC, RCA, PSC of DC, PSC of MD, and SCC of VA exercise statutory authority over matters such as tariffs, rates, construction, operations, financing, returns, accounting, and certain contracts with customers. In order to recognize the economic effects of the actions and decisions of the MPSC, RCA, PSC of DC, PSC of MD, and SCC of VA, the timing of recognition of certain assets, liabilities, revenues, and expenses as a result of regulation may differ from that otherwise expected using U.S. GAAP for entities not subject to rate regulation.

Regulatory assets represent future revenues associated with certain costs incurred in the current period or in prior periods that are expected to be recovered from customers in future periods through the rate setting process. Regulatory liabilities represent future reductions or limitations of increases in revenue associated with amounts that are expected to be refunded to customers through the rate setting process.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand, balances with banks, and investments in money market instruments with original maturities of less than three months.

Restricted Cash Holdings from Customers

Cash deposited, which is restricted and is not available for general use by AltaGas, is separately presented as restricted cash holdings in the Consolidated Balance Sheets. Pursuant to the acquisition of WGL Holdings, Inc. (the WGL Acquisition), rabbi trust funds were funded to satisfy certain Washington Gas executive and outside director retirement benefit plan obligations. The rabbi trust funds are invested in money market funds which are considered cash equivalents. These balances are included in "prepaid expenses and other current assets" and "long-term investments and other assets" in the Consolidated Balance Sheets.

Accounts Receivable

Receivables are recorded net of the allowance for doubtful accounts in the Consolidated Balance Sheets. AltaGas regularly analyzes and evaluates the collectability of the accounts receivable based on a combination of factors. If circumstances related to the collectability change, the allowance for doubtful accounts is further adjusted. Accounts are written off when collection efforts are complete and future recovery is unlikely.

Inventory

Inventory consists of materials, supplies, natural gas, natural gas liquids, crude oil and condensates, processed finished products, renewable energy credits, and emission compliance instruments which are valued at the lower of cost or net realizable value. Cost of inventory is assigned using a weighted average cost formula. In general, commodity costs and variable transportation costs are capitalized as gas in underground storage. Fixed costs, primarily pipeline demand charges and storage charges, are expensed as incurred through the cost of gas.

Property, Plant, and Equipment (PP&E), Depreciation and Amortization

Property, plant, and equipment are carried at cost. The Corporation depreciates the cost of capital assets, net of salvage value, on a straight-line basis over the estimated useful life of the assets, with the exception of rate-regulated utilities assets, for which depreciation is calculated on a straight-line basis or over the contract term of a specific agreement at rates as approved by the regulatory authorities.

The Utilities charge maintenance and repairs directly to operating expense and capitalize betterments and renewal costs. In accordance with regulatory requirements, depreciation expense includes an amount allowed for regulatory purposes to be collected in current rates for future removal and site restoration costs.

Interest costs are capitalized on major additions to property, plant, and equipment until the asset is ready for its intended use. The interest rate used for calculating the interest costs to be capitalized is based on AltaGas' prior quarter actual borrowing long-term interest rate.

The Utilities capitalize an imputed carrying cost on assets during construction as authorized by regulatory authorities and the amount so capitalized is an allowance for funds used during construction (AFUDC). AFUDC is the amount that a rate-regulated enterprise is allowed to recover for its cost of financing assets under construction. Capitalized overhead, administrative expenses, and AFUDC are included in the cost of the related assets and are recovered in rates charged to customers through depreciation expense, as allowed by the regulators.

The range of useful lives for AltaGas' PP&E is as follows:

Utilities assets	4 to 69 years
Midstream assets	1 to 43 years
Corporate/Other assets	3 to 46 years

As required by the regulatory authority, net additions to SEMCO's utility assets are amortized for one half-year in the year in which they are brought into active service. Net additions to WGL's assets are amortized in the month after they are brought into active service.

Generally, when a regulated asset is retired or disposed of, there is no gain or loss recorded in the Consolidated Statements of Income. Any difference between the cost and accumulated depreciation of the asset, net of salvage proceeds, is charged to accumulated depreciation or another regulatory asset or liability account. It is expected that any gain or loss that is charged to accumulated depreciation or another regulatory account will be reflected in future depreciation expense when it is refunded or collected in rates. When a non-regulated asset is retired or disposed of from PP&E, the original cost and related accumulated depreciation and amortization are derecognized and any gain or loss is recorded in the Consolidated Statements of Income.

Intangible Assets

Intangible assets are recorded at cost. Intangible assets which have a finite useful life are amortized on a straight-line basis over their term or estimated useful life. The range of useful lives for intangible assets with a finite life is as follows:

Energy services relationships	5 years
Software	3 to 20 years
Extraction and Transmission (E&T) Contracts	25 years
Commodity contracts	1 to 7 years

Assets Held for Sale

The Corporation classifies assets as held for sale when the carrying amount will be principally recovered through a sale transaction rather than through continuing use. This condition is met when Management approves and commits to a formal plan to sell the assets, the assets are available for immediate sale in their present condition, and Management expects the sale to close within the next 12 months. Upon classifying an asset as held for sale, an asset is recorded at the lower of its carrying value or the estimated fair value less cost to sell. Assets held for sale are not depreciated or amortized.

Business Acquisitions

Business acquisitions are accounted for using the acquisition method. Under the acquisition method, assets and liabilities of the acquired entity are recorded at fair value at the date of acquisition. Acquisition-related costs are expensed as incurred. Goodwill represents the excess of purchase price over the fair value of the net assets acquired. Management applies its best estimates and assumptions to determine the fair value of net assets acquired; however, the estimates are subject to further refinement of assumptions over a measurement period, which may be up to one year from the acquisition date. During the measurement period, adjustments to assets acquired and liabilities assumed may be recorded, with a corresponding impact to goodwill.

Provisions on Assets

If facts and circumstances suggest that a long-lived asset or an intangible asset may be impaired, the carrying value is reviewed. If this review indicates that the value of the asset is not recoverable, as determined by the projected undiscounted cash flows related to the asset over its remaining life, then the carrying value of the asset is reduced to its estimated fair value and an impairment loss is recognized.

Goodwill is not subject to amortization, but assessed at least annually for impairment, or more often when events or changes in circumstances indicate that goodwill may be impaired. The annual assessment of goodwill is performed at the reporting unit level, which is an operating segment or one level below. The Corporation has the option to first assess qualitative factors to determine whether events or changes in circumstances indicate that the goodwill may be impaired. If a quantitative impairment test is performed, the fair value of the reporting unit will be compared to its carrying value (including goodwill). If the carrying value of the reporting unit exceeds the fair value, goodwill is reduced to its fair value and an impairment loss would be recorded in the Consolidated Statements of Income.

Investments Accounted for by the Equity Method

The equity method of accounting is used for investments in which AltaGas has the ability to exercise significant influence, but does not have a controlling interest. Equity investments are initially measured at cost and are adjusted for the Corporation's proportionate share of earnings or losses. Equity investments are increased for contributions made and decreased for distributions received. To the extent an investee undertakes activities necessary to commence its planned principal operations, the Corporation will capitalize interest costs associated with its investment during such period.

The HLBV methodology is used to allocate earnings or losses for certain WGL equity method investments when WGL's ownership interest percentage is different than distribution percentages. When applying HLBV accounting, the Corporation determines the amount that it would receive if an equity investment entity were to liquidate all of its assets at book value (as valued in accordance with U.S. GAAP) and distribute that cash to the investors based on the contractually defined liquidation priorities. The change in the Corporation's claim on the equity investment entity's book value at the beginning and end of the reporting period (adjusted for contributions and distributions) is the Corporation's share of the earnings or losses from the equity investment for the period.

An equity method investment is reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of the investment may not be recoverable. When such condition is deemed other than temporary, the carrying value of the investment is written down to its fair value, and an impairment charge is recorded in the Consolidated Statements of Income.

Financial Instruments

Non-Utility Operations

All financial instruments are initially recorded at fair value unless they qualify for, and are designated under, a normal purchase and normal sale (NPNS) exemption. Subsequent measurement of the financial instruments is based on their classification. The financial assets are classified as "held-for-trading", "held-to-maturity", or "loans and receivables". Financial liabilities are classified as "held-for-trading" or other financial liabilities. Subsequent measurement is determined by classification.

A physical contract generally qualifies for the NPNS exemption if the transaction is reasonable in relation to AltaGas' business needs and AltaGas has the ability, and intent, to deliver or take delivery of the underlying item. AltaGas continually assesses the contracts designated under the NPNS exemption and will discontinue the treatment of these contracts under this exemption where the criteria are no longer met.

Held-for-trading instruments include non-derivative financial assets and financial assets and liabilities that may consist of swaps, options, forwards, and equity securities. These financial instruments are initially recorded at their fair value, with subsequent changes in fair value recorded in net income. Held-to-maturity, loans and receivables, and other financial liabilities are recognized at amortized cost using the effective interest method unless they are held-for-sale and recognized at the lower of cost or fair value less transaction fees.

Investments in equity instruments not accounted for under the equity method that do not have a quoted market price in an active market are measured at cost. Income earned from these investments is included in the Consolidated Statements of Income under "other income".

Derivatives embedded in other financial instruments or contracts (the host instrument) are recorded separately and are measured at fair value if the economic characteristics of the embedded derivative are not closely related to the host instrument, the terms of the embedded derivative are the same as those of a standalone derivative, and the entire contract is not held-for-trading or accounted for at fair value. Changes in fair value are included in earnings.

The fair values recorded on the Consolidated Balance Sheets reflect netting of the asset and liability positions where counterparty master netting arrangements contain provisions for net settlement.

Transaction costs related to the acquisition of held-for-trading financial assets and liabilities are expensed as incurred.

Transaction costs for obtaining debt financing other than line-of-credit arrangements are recognized as a direct deduction from the related debt liability on the Consolidated Balance Sheets. Transaction costs related to line-of-credit arrangements are capitalized and included under "long-term investments and other assets" on the Consolidated Balance Sheets. Premiums and discounts are netted against long-term debt on the Consolidated Balance Sheets. The deferred charges are amortized over the life of the related debt on an effective interest basis and included in “interest expense” on the Consolidated Statements of Income.

Regulated Utility Operations

All physical and financial derivative contracts are initially recorded at fair value. Changes in the fair value of derivative instruments that are recoverable or refunded to customers when they settle are recorded as regulatory assets or liabilities. Changes in the fair value of derivatives not affected by rate regulation are reflected in net income.

Transaction costs for obtaining debt financing and reacquired debt costs are recorded as regulatory assets or liabilities, or as a reduction of the debt liability on the Consolidated Balance Sheets.

Weather-Related Instruments

WGL purchases certain weather-related instruments, such as heating degree day (HDD) derivatives and cooling degree day (CDD) derivatives to manage weather and price risks related to its natural gas and electricity sales. These derivatives are accounted for in accordance with ASC 815-45, Derivatives and Hedging – Weather Derivatives. For HDD derivatives, gains or losses are recognized when the actual HDD’s falls above or below the contractual HDD’s for each instrument. For CDD derivatives, gains or losses are recognized when the average temperature exceeds or is below a contractually stated level during the contract period. Refer to Note 23 for further discussion on weather-related instruments.

Hedges

As part of its risk management strategy, AltaGas may use derivatives to reduce its exposure to commodity price, interest rate, and foreign exchange risk. AltaGas may designate certain outstanding loans to hedge against the currency translation effect of its foreign investments. No other derivatives have been designated as hedges under ASC Topic 815.

Non-Utility Operations

The change in fair value of cash flow hedges is recognized in OCI. Gains or losses from cash flow hedges are reclassified to net income when the hedged transaction affects earnings, such as when the hedged forecasted transaction occurs.

Regulated Utility Operations

During planned issuances of debt securities, Washington Gas may utilize derivative instruments to manage the risk of interest-rate volatility. Gains and losses associated with these types of derivatives are recorded as regulatory liabilities or assets, and amortized in accordance with regulatory requirements, typically over the life of the related debt.

Credit Losses

AltaGas regularly analyzes and evaluates the collectability of the accounts receivable based on a combination of factors. If circumstances related to the collectability change, the allowance for credit losses is adjusted. Accounts are written off when collection efforts are complete and future recovery is unlikely. See below for a description of how expected credit loss estimates are developed.

Utilities Customer Receivables and Contract Assets

AltaGas is exposed to risk through the non-payment of utility bills by customers. To manage this customer credit risk, AltaGas' regulated utilities customers are offered budget billing options or high risk customers may be required to provide a cash deposit until the requirement for deposit refunds are met. AltaGas can recover a portion of non-payments from customers in future periods through the rate-setting process. For accounts receivable generated by the Utilities business, an allowance for credit losses is recorded against revenue and is recognized using a historical loss-rate based on historical payment and collection experience. This rate may be adjusted based on Management's expectations of unusual macroeconomic conditions and other factors. AltaGas regularly evaluates the reasonableness of the allowance based on a combination of factors, such as: the length of time receivables are past due, historical expected payment, collection experience, financial condition of customers, and other circumstances that could impact customers' ability or desire to make payments. For retail energy marketing customer receivables where AltaGas has enrolled in a regulatory utility purchase of receivable program, the associated utility discount rate is used to determine credit losses.

Midstream Customer Receivables and Contract Assets

AltaGas operates under an existing credit policy that is designed to mitigate credit risk. Credit limits are established for each counterparty and credit enhancements such as letters of credit, parent guarantees, and cash collateral may be required. The creditworthiness of all counterparties is continuously monitored. A credit loss reserve is recorded for receivables with customers and trading counterparties AltaGas considers to be below investment grade by applying an estimated loss rate. The estimated loss rate is based on the historical default rates published by external rating agencies. For accounts receivable, a one-year rate is used. For contract assets, historical loss rates associated with the estimated time frame that the contract asset will be billed to the customer is used. In the event a customer or trading counterparty no longer exhibits similar risk characteristics, the associated receivable is evaluated individually.

Other

For other long-term receivables, associated counterparties are evaluated and assigned internal credit ratings based on AltaGas' credit policy. An allowance for credit losses is recorded based on historical default rates published by external credit rating agencies and a rate commensurate with the period in which the receivables are expected to be collected.

Debt

AltaGas uses short-term debt in the form of commercial paper and advances under its syndicated bank credit facilities to fund seasonal cash requirements. Short-term obligations are excluded from current liabilities if AltaGas has the ability and the intent to refinance these obligations on a long-term basis. The ability to refinance is primarily demonstrated through the availability of long-term revolving committed credit facilities in an amount equal to or greater than the expected maximum short-term obligation.

Asset Retirement Obligations

AltaGas recognizes asset retirement obligations in the period in which the legal obligation is incurred and a reasonable estimate of fair value can be determined. The associated asset retirement costs are capitalized as part of the carrying amount of the asset and are depreciated over the estimated useful life of the asset. The liability is increased due to the passage of time over the estimated period until the settlement of the obligation, with a corresponding charge to accretion expense for asset retirement obligations.

There are timing differences between accretion and depreciation amounts being recorded pursuant to GAAP and the recognition of depreciation expense for legal asset removal costs that are recovered in rates, as allowed by the regulators. These timing differences are recorded as a reduction to “regulatory liabilities” in accordance with ASC 980.

Certain midstream and utility assets will have future legal obligations on retirement, but an asset retirement obligation has not been recorded due to its indeterminate life and corresponding indeterminable timing and scope of these asset retirement obligations. The Utilities recognize asset retirement obligations for some interim retirements, as expected by their regulators.

Revenue Recognition

AltaGas has revenue from various sources, including rate-regulated revenue, commodity sales, midstream service contracts, gas sales and transportation services, and storage services. For a detailed description of the Corporation’s revenue recognition policy by major source of revenue, please refer to Note 24.

Foreign Currency Translation

Monetary assets and liabilities denominated in a foreign currency are converted to the functional currency using the exchange rate in effect at the balance sheet date. Adjustments resulting from the conversion are recorded in the Consolidated Statements of Income. Non-monetary assets and liabilities are converted at the historical exchange rate in effect at the transaction date. Revenues and expenses are converted at the exchange rate applicable at the transaction date.

For foreign entities with a functional currency other than Canadian dollars, AltaGas’ reporting currency, assets and liabilities are translated into Canadian dollars at the rate in effect at the reporting date. Revenues and expenses are translated at average exchange rates during the reporting period. All adjustments resulting from the translation of the foreign operations are recorded in OCI.

AltaGas may designate certain outstanding loans to hedge against the currency translation effect of its foreign investments. Accordingly, foreign exchange gains and losses, from the dates of designation, on the translation of these loans are included in OCI.

Share Options and Other Compensation Plans

Share options granted are recorded using fair value. Compensation expense is measured at the date of the grant using the Black-Scholes-Merton model and is recognized over the vesting period of the options. Consideration received by AltaGas on exercise of the share options is credited to shareholders’ equity.

AltaGas has a phantom unit plan (Phantom Plan, formerly the medium-term incentive plan) for employees, executive officers, and directors, which includes two types of awards: restricted units (RUs) and performance units (PUs). A portion of AltaGas’ RUs and PUs are valued based on the dividends declared during the vesting period and the weighted average share price of AltaGas' common shares multiplied by the units outstanding at the end of the vesting period. Upon vesting, the RUs and PUs are paid in cash. The other portion of RUs and PUs are valued at US$1 per unit. Upon vesting, the RUs and PUs are paid in cash. All PUs are also subject to a performance multiplier ranging from 0 to 2 dependent on the Corporation's performance relative to performance targets as approved by the Board of Directors. Compensation expense is recognized using the liability method and is recorded as operating and administrative expense over the vesting period. A change in value of the RUs or PUs is recognized in the period the change occurs. Forfeitures are recognized when they occur instead of estimating the number of awards that are expected to vest.

In addition, AltaGas has a deferred share unit plan (DSUP) for directors, officers, and employees as an additional form of long-term variable compensation incentive. Although the DSUP is available to directors, officers, and employees, AltaGas currently only grants deferred share units (DSUs) under the DSUP as a form of director compensation. The DSUs granted are fully vested upon being credited to a participant's account, the participant is entitled to payment upon retirement, and payment is not subject to satisfaction of any requirements as to any minimum period of membership or employment or other conditions. DSUs are accounted for at fair value. Compensation expense is determined based on the fair value of the DSUs on the date of the grant and fluctuations in fair value are recognized in the period the change occurs. Forfeitures are recognized when they occur instead of estimating the number of awards that are expected to vest.

Pension Plans and Post-Retirement Benefits

AltaGas maintains defined benefit pension plans, defined contribution plans, and other post-retirement benefit plans for eligible employees. Contributions made by the Corporation to the defined contribution plans are expensed in the period in which the contribution occurs.

The cost of defined benefit pension plans and post-retirement benefits is actuarially determined using the projected benefit method prorated based on service and Management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees, expected health care costs, and other actuarial factors including discount rates and mortality. Pension plan assets are measured at fair value. The expected return on plan assets is based on historical and projected rates of return for each asset class in the plan portfolio. The projected benefit obligation is discounted using the market interest rate on high-quality debt instruments with cash flows matching the timing and amount of benefit payments.

Unrecognized actuarial gains and losses in excess of 10 percent of the greater of the benefit obligation and the fair value of plan assets or the market-related value of assets along with any unamortized past service costs and credits are amortized on a straight-line basis over the expected average remaining service life of active employees.

AltaGas recognizes the overfunded or underfunded status of its pension and post-retirement benefit plans as either assets or liabilities in the Consolidated Balance Sheets. Unrecognized actuarial gains and losses and past service costs and credits that arise during the period are recognized in OCI or a regulatory asset or liability.

For certain regulated utilities, the Corporation expects to recover pension expense in future rates and therefore records unrecognized balances as either regulatory assets or liabilities. The regulatory assets or liabilities are amortized on a straight-line basis over the expected average remaining service life of active employees.

In 2020, AltaGas made a voluntary change in accounting principle for calculating the market-related value of assets (MRVA) used in the determination of Washington Gas' net periodic pension and other post-retirement benefit plan costs. The change uses the fair value approach for the fixed income investment asset class of the plan assets, compared to the prior method that utilized a calculated value where gains and losses arising from changes in fair value were deferred and amortized into the calculation of the MRVA over a period of five years. The MRVA is used in the calculation of the expected return on assets and the recognized actuarial gain or loss components of net periodic benefit cost. The approach applied for all other classes of assets remains unchanged. Management believes that using the fair value approach for the fixed income investments in plan assets is preferable as it more closely aligns the recognition of related components within the net periodic benefit cost.

Income Taxes

Income taxes for the Corporation and its subsidiaries are calculated using the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are determined based on differences between the carrying value and the tax basis of assets and liabilities and are measured using the enacted tax rates and laws that are in effect in the periods in which the differences are expected to be settled or realized. Deferred income tax assets are routinely reviewed, and a valuation allowance is recorded to reduce the deferred tax assets if it is more likely than not that deferred tax assets will not be realized.

The financial statement effects of an uncertain tax position are recognized when it is more likely than not, based on technical merits, that the position will be sustained upon examination by a taxing authority. The current and deferred tax impact is equal to the largest amount, considering possible settlement outcomes, that is greater than 50 percent likely of being realized upon settlement with the taxing authorities.

Investment tax credits are recognized as reductions to income tax expense over the estimated service lives of the related properties.

The rate-regulated natural gas distribution subsidiaries recognize a separate regulatory asset or liability for the amount of deferred income taxes expected to be recovered from, or paid to, customers in the future. Any tax related interest and/or penalty incurred is included in interest expense.

Net Income per Share

Basic net income per common share is computed using the weighted average number of common shares outstanding during the period. Dilutive net income per common share is calculated using the weighted average number of common shares outstanding adjusted for dilutive common shares related to the Corporation’s share-based compensation awards.

The potentially dilutive impact of the share-based compensation awards is determined using the treasury stock method. Under the treasury stock method, awards are treated as if they had been exercised with any proceeds used to repurchase common stock at the average market price during the period. Any incremental difference between the assumed number of shares issued and purchased is included in the diluted share computation.

Contingencies

Liabilities for loss contingencies arising from claims, assessments, litigation and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Any such accruals are adjusted thereafter as additional information becomes available or circumstances change.

Leases

The following are the Corporation’s significant accounting policies:

Leases – Lessee

AltaGas determines if an arrangement is a lease at inception. Operating leases are included in right-of-use (ROU) assets, current operating lease liabilities, and long-term operating lease liabilities in the Consolidated Balance Sheets. Finance leases are included in property, plant and equipment and current and long-term debt in the Consolidated Balance Sheets.

ROU assets represent the right to use an underlying asset for the lease term and lease liabilities represent the obligation to make lease payments arising from the lease. Operating lease ROU assets and liabilities are recognized at commencement date based on the present value of lease payments over the lease term. AltaGas uses the rate implicit in the lease when readily determinable. When the implicit lease rate is not readily determinable, AltaGas uses its incremental borrowing rate to determine the present value of lease payments. AltaGas includes lessee options to renew or terminate the lease term in the determination of the ROU asset and lease liability when exercise is reasonably certain. The operating lease ROU asset is adjusted for lease payments made in advance of the commencement date, initial direct costs, and any lease incentives.

Operating lease expense is recognized on a straight-line basis over the lease term in "operating and administrative expense". Depreciation and interest expense are recorded on finance leases.

Leases – Lessor

AltaGas determines if an arrangement is a lease at inception. Lease payments under an operating lease are recognized on a straight-line basis over the term of the lease. Variable lease payments are recognized as revenue as the facts and circumstances on which the variable lease payment is based occur.

AltaGas does not include taxes assessed by governmental authorities, such as sales and related taxes, in the lease payments or variable lease payments.

ADOPTION OF NEW ACCOUNTING STANDARDS

Effective January 1, 2021, AltaGas adopted the following Financial Accounting Standards Board (FASB) issued Accounting Standards Updates (ASU):

- In December 2019, FASB issued ASU No. 2019-12 “Income Taxes: Simplifying the Accounting for Income Taxes". The amendments in this ASU simplify the accounting for income taxes by clarifying certain aspects of current guidance and removing some exceptions to the general principles in ASC 740. The adoption of this ASU did not have a material impact on AltaGas’ consolidated financial statements;

- In January 2020, FASB issued ASU No. 2020-01 “Derivatives and Hedging: Clarifying the Interactions between Topic 321, Topic 323, and Topic 815". The amendments in this ASU clarify the application of the measurement alternative for equity instruments and the measurement of non-derivative forward contracts or purchased call options used to acquire equity securities. The adoption of this ASU did not have a material impact on AltaGas’ consolidated financial statements; and

- In March 2020, FASB issued ASU No. 2020-04 "Reference Rate Reform: Facilitation of the Effects of Reference Rate Reform on Financial Reporting". The amendments in this ASU provide optional expedients and exceptions for applying GAAP to contract modifications and hedging relationships affected by reference rate reform if certain criteria are met. These apply only to contracts, hedging relationships, and other transactions that reference the London Interbank Offered Rate (LIBOR) or another reference rate expected to be discontinued because of reference rate reform. Certain of AltaGas' credit facilities, lessee vehicle finance leases, and carrying charges in certain derivative commodity sale arrangements reference LIBOR. The discontinuation of LIBOR will require these arrangements to be modified to replace LIBOR with an alternative interest rate. As such, AltaGas has made a policy election to adopt the contract modification optional expedients related to these arrangements on January 1, 2021 on a prospective basis. As a result of electing these optional expedients, contract modifications due to LIBOR are not expected to have a material effect on AltaGas' consolidated financial statements. AltaGas will continue to monitor the activities of regulators and financial institutions to transition to an alternative reference rate and continue to review additional arrangements for references to LIBOR. Accordingly, AltaGas may make additional optional elections in the future.

FUTURE CHANGES IN ACCOUNTING PRINCIPLES

In August 2020, FASB issued ASU No. 2020-06 "Debt with Conversion and Other Options and Topic 815-40 - Derivatives and Hedging - Contracts in Entity's Own Equity: Accounting for Convertible Instruments and Contract in an Entity's Own Equity". The amendments in this ASU simplify the accounting for certain financial instruments with characteristics of liabilities and equity, including convertible instruments and contracts in an entity's own equity. The amendments in this ASU are effective for public business entities that meet the definition of a Securities and Exchange Commission (SEC) filer, excluding entities eligible to be smaller reporting companies as defined by the SEC, for fiscal years beginning after December 15, 2021, including interim periods within those fiscal years. For all other entities, the amendments are effective for fiscal years beginning after December 15, 2023, including interim periods within those fiscal years. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated financial statements.

In July 2021, FASB issued ASU No. 2021-05 "Leases (Topic 842): Lessors - Certain Leases with Variable Lease Payments." The amendments in this ASU affect lessors with lease contracts that have variable lease payments that do not depend on a reference index or a rate and would have resulted in the recognition of a selling loss at lease commencement if classified as sales-type or direct financing. The amendments are effective for fiscal years beginning after December 15, 2021, including interim periods within those fiscal years and could either be applied retrospectively to leases that commenced or were modified upon the adoption of ASC 842 or prospectively to new or modified leases. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

In October 2021, FASB issued ASU 2021-08 "Business Combinations (Topic 805): Accounting for Contract Assets and Contract Liabilities from Contracts with Customers". The amendments in this ASU require an entity to recognize and measure contract assets and liabilities acquired in a business combination in accordance with Topic 606. The amendments in this ASU are effective for fiscal years beginning after December 15, 2022 and should be applied prospectively to business combinations occurring on or after the effective date of the amendment. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

In November 2021, FASB issued ASU No. 2021-10 "Government Assistance (Topic 832): Disclosures by Business Entities about Government Assistance". The amendments in this ASU require annual disclosure about transactions with a government entity, including the nature of the transactions, the method applied to account for the government assistance, impacted line items on the financial statements, and significant terms and conditions of the agreement. The amendments in this ASU are effective for fiscal years beginning after December 15, 2021 and could either be applied prospectively to all new transactions with a government that are entered into after the date of initial application or retrospectively to those transactions. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

3. Acquisition of Petrogas Energy Corporation

On December 15, 2020, following the receipt of all required approvals, AltaGas acquired an additional 37 percent of Petrogas Energy Corp. for total cash consideration upon close of approximately $715 million. Additional post-acquisition contingent payments of up to $16 million may be paid no later than 2022 based on certain criteria, including earnings targets being met (Note 29). AltaGas funded the transaction through draws on its existing credit facilities. As a result of the transaction, AltaGas' ownership in Petrogas has increased to approximately 74 percent with Idemitsu Kosan Co., Ltd. (Idemitsu) owning the remaining approximately 26 percent. Subsequent to the transaction, AltaGas controls Petrogas and as such, Petrogas results have been consolidated for the period subsequent to close.

This acquisition is consistent with AltaGas' global export strategy, growing Midstream operations, and corporate focus on building a diversified, low-risk, high-growth Utilities and Midstream business. The transaction provides AltaGas with operational responsibility of strategic assets that, along with the Ridley Island Propane Export Terminal and existing Midstream assets, position the Company to capture efficiencies that are expected to accrue to shareholders and customers.

AltaGas accounted for the acquisition as a business combination achieved in stages and re-measured its previously held 37 percent equity investment in Petrogas at an acquisition date fair value of $631 million. The fair value of assets and liabilities acquired were determined using a combination of income and cost approach. The fair value of the previously held interest and non-controlling interests were derived from the valuation of the assets and liabilities including considerations for expected synergies. Prior to the acquisition, AltaGas' indirect non-controlling interest in Petrogas was accounted for as an investment accounted for by the equity method (Note 14).

The following table summarizes the purchase price allocation representing the consideration paid and the estimated fair value of the net assets acquired as at December 15, 2020. The purchase price allocation was completed prior to the end of the measurement period and reflects Management's best estimate of the fair value of Petrogas' assets and liabilities. In 2021, goodwill was increased by approximately $147 million (Note 11) based on new information obtained during the measurement period.

Fair value of previously held interest in AltaGas Idemitsu Joint Venture LP (AIJVLP) on the acquisition date	**$**	**631**
Less: Carrying value of previously held interest in AIJVLP		**(609)**
Gain on re-measurement of previously held interest	**$**	**22**
Purchase consideration for an additional 37 percent of Petrogas	**$**	**715**
Deemed settlement of intercompany debt		**120**
Fair value of previously held interest on the acquisition date		**631**
Less: Fair value assigned to net assets		
Current assets		542
Property, plant and equipment		499
Intangible assets		8
Operating right-of-use assets		196
Investments accounted for by the equity method		125
Current liabilities		(521)
Long-term debt		(48)
Asset retirement obligations		(18)
Deferred income taxes		7
Operating lease liabilities		(155)
Other long-term liabilities		(20)
Fair value of net assets acquired	**$**	**615**
Fair value of AIJVLP's non-controlling interest in Petrogas on the acquisition date		**467**
Goodwill	**$**	**1,318**

4. Dispositions

WGL Midstream Assets

On April 23, 2021, AltaGas completed the sale of the majority of WGL Midstream's commodity business for cash proceeds of approximately $341 million (US$275 million). The disposition included goodwill of $13 million (Note 11). For the year ended December 31, 2021, AltaGas recognized a pre-tax gain on disposition of approximately $3 million in the Consolidated Statements of Income under the line item "other income".

Distributed Generation Assets

In the second quarter of 2021, all consents and approvals were obtained and AltaGas transferred ownership of the last remaining distributed generation project that was previously classified as held for sale. For the year ended December 31, 2021, AltaGas recognized a pre-tax loss on disposition of approximately $1 million in the Consolidated Statements of Income under the line item "other income" related to projects transferred in 2021.

Other Midstream Asset Sales

In 2021, additional minor asset sales within the Midstream segment were completed for cash proceeds of approximately $5 million. As a result, AltaGas recognized a pre-tax gain on disposition of approximately $1 million in the Consolidated Statements of Income under the line item "other income" for the year ended December 31, 2021.

Petrogas Propane Distribution Assets

In the third quarter of 2021, AltaGas completed the sale of certain Petrogas propane distribution assets for cash proceeds of less than $1 million. As a result, AltaGas recognized a pre-tax loss on disposition of less than $1 million in the Consolidated Statements of Income under the line item "other income" for the year ended December 31, 2021.

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. Upon close of the sale, various escrow accounts were established to provide the purchaser a form of recourse for the settlement of indemnification obligations. In 2021, AltaGas received approximately $3 million (US$2 million) cash proceeds from the indemnity escrow account. As a result, AltaGas recognized a pre-tax gain on disposition of approximately $3 million in the Consolidated Statements of Income under the line item "other income" for the year ended December 31, 2021.

5. Assets Held For Sale

As at	**December 31, 2021**	December 31, 2020
Assets held for sale		
Property, plant and equipment	**$ —**	$ 4
	$ —	$ 4
Liabilities associated with assets held for sale		
Unamortized investment tax credits	**$ —**	$ 1
	$ —	$ 1

Distributed Generation Assets

Assets held for sale and liabilities associated with assets held for sale at December 31, 2020 related to the last remaining distributed generation project which had not yet transferred to the purchaser. This project transferred to the purchaser in the second quarter of 2021 (Note 4) and as such, there are no longer any distributed generation assets held for sale at December 31, 2021.

6. Provisions on Assets

Year Ended December 31		2021		2020
Midstream	**$**	**59**	$	106
Corporate/Other		**5**		3
	$	**64**	$	109

Midstream

In 2021, AltaGas recorded pre-tax provisions of $59 million primarily related to the sale of the majority of WGL Midstream's commodity business as well as certain non-core development stage Midstream projects that are no longer being developed. The pre-tax provisions were primarily recorded against intangible assets. In 2020, AltaGas recorded pre-tax provisions of $106 million of which $104 million related to the Alton Natural Gas Storage Project and the remaining $2 million related to land parcels located near the Harmattan gas processing plant which were sold in the second quarter of 2020.

Corporate/Other

In 2021, AltaGas recorded a pre-tax provision of $5 million related to the Parks at Walter Reed thermal plant in Washington, D.C. which was impaired as the carrying value exceeded future expected cash flows from the asset. In 2020, AltaGas recorded pre-tax provisions of $3 million related to the remaining U.S. distributed generation project which had not yet transferred to the purchaser and was classified as held for sale as at December 31, 2020. The pre-tax provisions were recorded against property, plant and equipment.

7. Inventory

As at December 31		2021		2020
Natural gas held in storage [(a)]	**$**	**341**	$	309
Natural gas liquids		**175**		116
Materials and supplies		**70**		61
Renewable energy credits and emission compliance instruments		**82**		80
Crude oil and condensate		**109**		66
Processed finished products		**5**		4
	$	**782**	$	636

(a) As at December 31, 2021, $304 million of the natural gas held in storage was held by rate-regulated utilities (2020 - $193 million).

8. Property, Plant and Equipment

As at	December 31, 2021			December 31, 2020		
	Cost	**Accumulated amortization**	**Net book value**	Cost	Accumulated amortization	Net book value
Utilities	**$ 8,432**	**$ (437)**	**$ 7,995**	$ 7,791	$ (286)	$ 7,505
Midstream	**3,898**	**(793)**	**3,105**	3,832	(689)	3,143
Corporate/Other	**840**	**(617)**	**223**	842	(598)	244
Reclassified to assets held for sale	**—**	**—**	**—**	(4)	—	(4)
	$ 13,170	**$ (1,847)**	**$ 11,323**	$ 12,461	$ (1,573)	$ 10,888

Interest capitalized on long-term capital construction projects for the year ended December 31, 2021 was $1 million (2020 - $6 million).

As at December 31, 2021, the Corporation had approximately $570 million (December 31, 2020 - $457 million) of capital projects under construction that were not yet subject to amortization.

Depreciation expense related to property, plant and equipment (including assets under capital leases) for the year ended December 31, 2021 was $365 million (2020 - $346 million).

9. Intangible Assets

As at	December 31, 2021			December 31, 2020		
	Cost	**Accumulated amortization**	**Net book value**	Cost	Accumulated amortization	Net book value
E&T contracts	**$ 26**	**$ (17)**	**$ 9**	$ 26	$ (16)	$ 10
Energy services relationships	**90**	**(63)**	**27**	90	(45)	45
Software	**331**	**(203)**	**128**	304	(133)	171
Land rights	**1**	**—**	**1**	1	—	1
Commodity contracts [(a)]	**7**	**(1)**	**6**	332	(20)	312
	$ 455	**$ (284)**	**$ 171**	$ 753	$ (214)	$ 539

(a) The majority of commodity contracts were disposed of in April 2021 through the disposition of the majority of WGL Midstream's commodity business (Note 4).

Amortization expense related to intangible assets for the year ended December 31, 2021 was $57 million (2020 - $68 million).

As at December 31, 2021, the Corporation excluded $7 million (December 31, 2020 - $176 million) from the asset base subject to amortization. Items excluded relate to software assets under development and assets with an indefinite life.

The following table sets forth the estimated amortization expense of intangible assets, excluding any amortization of assets not yet subject to amortization as well as assets with an indefinite life, for the years ended December 31:

2022	**$**	**60**
2023	**$**	**44**
2024	**$**	**30**
2025	**$**	**24**
2026	**$**	**1**
Thereafter	**$**	**5**

10. Leases

Lessee

AltaGas has operating and finance leases for office space, office equipment, field equipment, rail cars, aquatic use, vehicles, power and gas facilities, transmission and distribution assets, and land.

The components of lease expense were as follows:

		Year Ended December 31, 2021		Year Ended December 31, 2020
Operating lease cost (includes variable lease payments)	**$**	**96**	$	43
Finance lease cost				
Amortization of right-of-use assets		**6**		4
Total finance lease cost	**$**	**6**	$	4
Total lease cost	**$**	**102**	$	47

Supplemental cash flow information related to leases was as follows:

Year Ended December 31		**2021**		2020
Cash paid for amounts included in the measurement of lease liabilities:				
Operating cash flows used by operating leases	**$**	**(96)**	$	(36)
Financing cash flows used by finance leases [(a)]	**$**	**(6)**	$	(4)
Right-of-use assets obtained in exchange for new lease liabilities				
Operating leases	**$**	**38**	$	227
Finance leases	**$**	**10**	$	6

(a) Included within repayment of long-term debt on the Consolidated Statements of Cash Flows.

Supplemental balance sheet information related to leases was as follows:

As at December 31		**2021**		2020
Operating Leases				
Operating lease right-of-use assets				
Long-term	**$**	**311**	$	372
Total operating lease right-of-use assets	**$**	**311**	$	372
Operating lease liabilities				
Current	**$**	**(91)**	$	(95)
Long-term		**(253)**		(304)
Total operating lease liabilities	**$**	**(344)**	$	(399)
Finance Leases				
Property and equipment, gross	**$**	**29**	$	19
Accumulated depreciation		**(12)**		(7)
Property and equipment, net	**$**	**17**	$	12
Current portion of long-term debt	**$**	**(6)**	$	(4)
Long-term debt		**(11)**		(8)
Total finance lease liabilities	**$**	**(17)**	$	(12)

As at	December 31, 2021	December 31, 2020
Weighted average remaining lease term (years)		
Operating leases	**6.9**	7.4
Finance leases	**4.3**	4.8
Weighted average discount rate (%)		
Operating leases	**2.45**	2.42
Finance leases	**2.23**	2.89

Maturity analysis of lease liabilities was as follows:

	Operating Leases	Finance Leases
2022	$ 92	$ 6
2023	70	5
2024	56	4
2025	42	2
2026	35	—
Thereafter	90	2
Total lease payments	$ 385	$ 19
Less: imputed interest	(41)	(2)
Total	$ 344	$ 17

Lessor

Certain of AltaGas' revenues are obtained through power purchase agreements or 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. Contingent rentals are recorded when the condition that created the present obligation to make such payments occurs such as when actual electricity is generated and delivered.

Maturity analysis of lease receivables was as follows:

	Operating Leases
2022	$ 70
2023	68
2024	2
2025	2
2026	2
Thereafter	72
Total	$ 216

The carrying value of property, plant, and equipment associated with these leases was approximately $202 million as at December 31, 2021.

AltaGas manages its risk associated with the residual value of its leased assets through strategically constructing leased facilities in key commercial regions and retaining the ability to sell commodities and ancillary services via the merchant market or through commodity sales agreements.

11. Goodwill

As at		December 31, 2021		December 31, 2020
Balance, beginning of year	**$**	**5,039**	$	3,942
Business acquisition *(note 3)*		**—**		1,171
Adjustment to goodwill on business acquisition *(note 3)*		**147**		—
Goodwill included in dispositions *(note 4)*		**(13)**		—
Foreign exchange translation		**(20)**		(74)
Balance, end of year	**$**	**5,153**	$	5,039

12. Long-Term Investments and Other Assets

As at		December 31, 2021		December 31, 2020
Deferred lease receivable	**$**	**15**	$	12
Debt issuance costs associated with credit facilities		**8**		3
Refundable deposits		**9**		9
Prepayment on long-term service agreements		**72**		70
Deferred information technology costs		**6**		4
Cash calls from joint venture partners [(a)]		**23**		26
Contract asset *(net of credit losses of $1 million) (notes 23 and 24)*		**41**		50
Rabbi trust *(notes 28 and 31)*		**10**		19
Other long-term receivables		**—**		18
Capitalized contract costs		**5**		5
Financial transmission rights		**17**		12
Other		**21**		17
	$	**227**	$	245

(a) Represents a cash advance to a joint venture partner as part of a construction, ownership and operation (CO&O) agreement.

13. Variable Interest Entities

Consolidated VIEs

AltaGas consolidates a variable interest entity (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. AltaGas and Royal Vopak have provided limited guarantees for the obligations of their respective subsidiaries for the construction cost of RIPET. With the commencement of commercial operations at RIPET, 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 AltaGas' consolidated VIE:

As at	**December 31, 2021**	December 31, 2020
Current assets	**$ 6**	$ 7
Property, plant and equipment	**357**	358
Long-term investments and other assets	**47**	50
Current liabilities	**(8)**	(2)
Asset retirement obligations	**(3)**	(2)
Net assets	**$ 399**	$ 411

Unconsolidated VIE

<u>Strathcona Storage Limited Partnership (SSLP)</u>

Upon the acquisition of Petrogas on December 15, 2020, AltaGas acquired an indirect 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 four underground NGL storage salt caverns in service, with a fifth cavern under development.

As at December 31, 2021, AltaGas held an indirect 30 percent equity investment in SSLP with a carrying value of $131 million (2020 - $124 million), inclusive of fair value adjustments on acquisition date (Note 3). SSLP is not consolidated by Petrogas and instead is accounted for by the equity method of accounting. Petrogas 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.

14. Investments Accounted for by the Equity Method

Description	Location	Ownership Percentage	Carrying value as at December 31 2021	2020	Equity income (loss) for the year ended December 31 2021	2020
AltaGas Canada Inc. (ACI) [(a)]	Canada	—	**$ —**	$ —	**$ —**	$ 3
AltaGas Idemitsu Joint Venture LP (AIJVLP) [(b)]	Canada	—	**—**	—	**—**	(25)
Constitution Pipeline, LLC (Constitution) [(c)]	United States	—	**—**	—	**—**	(7)
Eaton Rapids Gas Storage System	United States	**50**	**27**	26	**2**	2
Mountain Valley Pipeline, LLC (MVP) [(d)]	United States	**10**	**447**	718	**(271)**	62
Sarnia Airport Storage Pool LP	Canada	**50**	**17**	18	**1**	1
Petrogas Preferred Shares [(e)]	Canada	**n/a**	**—**	—	**—**	13
Petrogas Terminals Penn LLC [(f)]	United States	**37**	**1**	1	**—**	—
Strathcona Storage LP [(f)]	Canada	**30**	**131**	124	**7**	—
			$ 623	$ 887	**$ (261)**	$ 49

(a) ACI was acquired by the Public Sector Pension Investment Board and the Alberta Teachers' Retirement Fund Board on March 31, 2020.

(b) Upon acquisition of Petrogas on December 15, 2020 (Note 3), AltaGas no longer has an equity investment in AIJVLP.

(c) In February 2020, the partners of Constitution elected not to proceed with the pipeline project and Constitution was dissolved. The loss recorded in 2020 relates to a provision recorded against the equity investment.

(d) The equity method is considered appropriate because MVP is an LLC with specific ownership accounts and ownership between five and fifty percent, resulting in WGL Midstream exercising a more than minor influence over the investee's operating and financing policies. In 2021, a provision was recorded against the equity investment in MVP due to ongoing legal and regulatory issues.

(e) Petrogas' preferred shares ceased to be an investment accounted for by the equity method after AltaGas acquired a controlling interest in Petrogas on December 15, 2020 (Note 3).

(f) Acquired on December 15, 2020 as part of the Petrogas Acquisition (Note 3).

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, and a contractual cap on contributions to MVP.

Summarized combined financial information, assuming a 100 percent ownership interest in AltaGas' equity investments listed above, is as follows:

Year Ended December 31 [(a)]	2021	2020
Revenues	**$ 97**	$ 828
Expenses	**(23)**	(181)
	$ 74	$ 647

As at December 31 [(a)]	2021	2020
Current assets	**$ 206**	$ 351
Property, plant and equipment	**$ 8,571**	$ 7,598
Long-term investments and other assets	**$ 3**	$ 5
Current liabilities	**$ (214)**	$ (281)
Other long-term liabilities	**$ (12)**	$ (2)

(a) For equity investments that were disposed of in the periods presented, revenues and expenses reflect the period prior to disposition and balance sheet amounts are $nil. For equity investments that were acquired in the periods presented (Note 3), revenues and expenses reflect the period subsequent to acquisition and balance sheet amounts are included as at December 31, 2020 and December 31, 2021.

Provisions on investments accounted for by the equity method

In 2021, AltaGas recorded a pre-tax provision on equity investments of approximately $271 million in the Consolidated Statements of Income under the line item "income (loss) from equity investments" related to its investment in MVP. The provision is a result of continued legal and regulatory challenges associated with the Mountain Valley Pipeline and MVP Southgate projects. The fair value of AltaGas' investment in MVP was calculated using a discounted cash flow model, taking into account the cap on the Company's contractual capital contributions, cost of capital, an assessment of the probability that MVP will overcome legal and regulatory challenges, and the potential removal costs should the project not move forward. Significant assumptions included an after-tax discount rate of approximately 5 percent. The valuation is considered a Level 3 fair value estimate. In 2020, AltaGas recorded a pre-tax provision on equity investments of approximately $7 million in the Consolidated Statements of Income under the line item "income (loss) from equity investments" for costs associated with AltaGas' equity investment in the Constitution pipeline project which was canceled in February 2020.

15. Short-term Debt

As at		**December 31, 2021**		December 31, 2020
Commercial paper [(a)]	**$**	**161**	$	236
Project financing		**8**		20
	$	**169**	$	256

(a) 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.

Project Financing

WGL and certain of its subsidiaries previously obtained third-party project financing on behalf of the United States federal government to provide funds for the construction of certain energy management services projects entered into under Washington Gas' area-wide contract. When these projects are formally accepted by the government and deemed complete, the ownership of the receivable is assigned to the third-party lender in satisfaction of the obligation, removing both the receivable and the obligation related to the financing from the Consolidated Financial Statements. As at December 31, 2021, draws related to project financing were $8 million (December 31, 2020 - $20 million).

Credit Facilities

As at December 31, 2021, AltaGas held a $70 million (December 31, 2020 - $70 million) unsecured demand revolving operating credit facility with a Canadian chartered bank. Draws on the facility bear interest at the lender's prime rate or at the bankers' acceptance rate plus a stamping fee. Letters of credit outstanding under this facility as at December 31, 2021 were $34 million (December 31, 2020 - $nil).

As at December 31, 2021, AltaGas held a US$200 million (December 31, 2020 - US$200 million) unsecured bilateral letter of credit demand facility with a Canadian chartered bank. Borrowings on the facility incur fees and interest at rates relevant to the nature of the draws made. Letters of credit outstanding under this facility as at December 31, 2021 were $139 million (December 31, 2020 - $190 million).

As at December 31, 2021, AltaGas held a US$125 million (December 31, 2020 - $nil) demand letter of credit facility. Letters of credit outstanding under this facility as at December 31, 2021 were $99 million (December 31, 2020 - $nil).

WGL and Washington Gas use short-term debt in the form of commercial paper and advances under its syndicated bank credit facilities 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. As at December 31, 2021, commercial paper outstanding classified as short-term debt totaled $161 million (December 31, 2020 - $236 million).

As at December 31, 2021, Petrogas held a $30 million (December 31, 2020 - $30 million) unsecured bilateral letter of credit demand facility. Letters of credit outstanding under this facility as at December 31, 2021 were $7 million (December 31, 2020 - $22 million).

As at December 31, 2021, Petrogas held an unsecured bilateral letter of credit demand facility of $25 million (December 31, 2020 - $25 million). Letters of credit outstanding under this facility as at December 31, 2021 were $nil (December 31, 2020 - $nil).

16. Long-Term Debt

As at	Maturity date	December 31, 2021	December 31, 2020
Credit facilities			
$2 billion unsecured extendible revolving facility [(a)] [(b)]	4-May-2026	**$ 375**	$ 802
US$150 million unsecured extendible revolving facility	20-Dec-2026	**120**	81
Commercial paper [(c)]	Various	**469**	260
$200 million secured extendible revolving facility [(d)]	28-Sep-2025	**—**	51
AltaGas Ltd. medium-term notes (MTNs)			
$350 million Senior unsecured - 3.72 percent	28-Sep-2021	**—**	350
$500 million Senior unsecured - 2.61 percent	16-Dec-2022	**500**	500
$300 million Senior unsecured - 3.57 percent	12-Jun-2023	**300**	300
$200 million Senior unsecured - 4.40 percent	15-Mar-2024	**200**	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
$200 million Senior unsecured - 2.17 percent	16-Mar-2027	**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
$200 million Senior unsecured - 2.48 percent	30-Nov-2030	**200**	200
$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
WGL and Washington Gas MTNs and private placement notes			
US$20 million Senior unsecured - 6.65 percent	20-Mar-2023	**25**	25
US$41 million Senior unsecured - 5.44 percent	11-Aug-2025	**51**	52
US$53 million Senior unsecured - 6.62 to 6.82 percent	Oct 2026	**67**	67
US$72 million Senior unsecured - 6.40 to 6.57 percent	Feb - Sep 2027	**91**	92
US$52 million Senior unsecured - 6.57 to 6.85 percent	Jan - Mar 2028	**66**	66
US$9 million Senior unsecured - 7.50 percent	1-Apr-2030	**11**	11
US$50 million Senior unsecured - 5.70 to 5.78 percent	Jan - Mar 2036	**63**	64
US$75 million Senior unsecured - 5.21 percent	3-Dec-2040	**95**	95
US$75 million Senior unsecured - 5.00 percent	15-Dec-2043	**95**	95
US$300 million Senior unsecured - 4.22 to 4.60 percent	Sep - Nov 2044	**380**	382
US$450 million Senior unsecured - 3.80 percent	15-Sep-2046	**572**	573
US$400 million Senior unsecured - 3.65 percent [(e)]	15-Sep-2049	**528**	530
US$200 million Senior unsecured - 2.98 percent	15-Dec-2051	**254**	—
SEMCO long-term debt			
US$82 million CINGSA Senior Secured - 4.48 percent [(f)]	2-Mar-2032	**63**	69
US$225 million First Mortgage Bonds - 3.15 percent	21-Apr-2050	**285**	286
US$225 million First Mortgage Bonds - 2.45 percent	21-Apr-2030	**285**	286
Fair value adjustment on WGL acquisition		**77**	80
Finance lease liabilities *(note 10)*		**17**	12
		$ 8,239	$ 8,029
Less debt issuance costs		**(44)**	(43)
		$ 8,195	$ 7,986
Less current portion		**(511)**	(360)
		$ 7,684	$ 7,626

(a) Borrowings on the facility can be by way of prime loans, U.S. base-rate loans, LIBOR loans, bankers' acceptances, or letters of credit. Borrowings on the facility have fees and interest at rates relevant to the nature of the draw made.

(b) During the second quarter of 2021, AltaGas closed an amendment that caused all committed credit facilities in Canada to be consolidated into a $2.3 billion facility. The facility has a $2 billion five-year extendable committed revolving tranche and a $300 million two-year extendable side car liquidity revolving facility.

(c) Commercial paper is supported by the availability of long-term committed credit facilities with maturity dates ranging from 2022 to 2024. Commercial paper intended to be repaid within the next year is recorded as short-term debt (Note 15).

(d) During the third quarter of 2021, Petrogas closed an amendment that caused all committed Petrogas credit facilities to be consolidated into a four-year $200 million facility.

(e) On December 10, 2020, Washington Gas issued MTNs with an aggregate principal amount of US$100 million. This offering constituted the reopening of its US$300 million MTNs originally issued in 2019. The total includes a US$17 million premium which will be amortized as a reduction to interest expense over the term of the note.

(f) Collateral for the CINGSA Senior secured loan is certain CINGSA assets. Alaska Storage Holding Company, LLC, a subsidiary in which AltaGas has a controlling interest, is the non-recourse guarantor of this loan.

Credit Facilities

As at December 31, 2021, AltaGas held a $2.3 billion (December 31, 2020 - $1.4 billion) unsecured revolving credit facility. Draws on the facility can be by way of prime loans, U.S. base-rate loans, LIBOR loans, bankers' acceptances, or letters of credit. Outstanding bank loans under this facility as at December 31, 2021 were $375 million (December 31, 2020 - $802 million).

As at December 31, 2021, WGL held a US$300 million (December 31, 2020 - US$250 million) unsecured revolving credit facility. Draws on the facility can be by way of prime loans, U.S. base-rate loans, LIBOR loans, bankers’ acceptances, or letters of credit. There were no outstanding bank loans under this facility as at December 31, 2021 or December 31, 2020.

As at December 31, 2021, Washington Gas held a US$450 million (December 31, 2020 - US$450 million) unsecured revolving credit facility. Draws on the facility can be by way of prime loans, U.S. base-rate loans, LIBOR loans, bankers’ acceptances, or letters of credit. There were no outstanding bank loans under this facility as at December 31, 2021 or December 31, 2020.

WGL and Washington Gas use short-term debt in the form of commercial paper and advances under its syndicated bank credit facilities 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. As at December 31, 2021, outstanding commercial paper classified as long-term debt totaled $469 million (December 31, 2020 - $260 million).

As at December 31, 2021, SEMCO held a US$150 million (December 31, 2020 - US$150 million) unsecured extendible revolving facility. Draws on the facility can be by way of letters of credit, Alternate Base Rate or Eurodollar loans. There were US$95 million outstanding bank loans under this facility as at December 31, 2021 (December 31, 2020 - US$81 million).

As at December 31, 2021, Petrogas held a $200 million (December 31, 2020 - $175 million) unsecured extendible revolving credit facility. Draws on the facility can be by way of prime loans, U.S. base-rate loans, LIBOR loans, bankers’ acceptances, or letters of credit. Loans and letters of credit outstanding under this facility as at December 31, 2021 were $nil (December 31, 2020 - $51 million).

As at December 31, 2021, Petrogas held a $25 million (December 31, 2020 - $25 million) swingline facility. Draws on the facility can be by way of prime loans or U.S. base-rate loans. There were no outstanding bank loans under this facility as at December 31, 2021 (December 31, 2020 - $6 million).

During the year ended December 31, 2021, Petrogas cancelled a US$40 million seasonal bulge facility and a US$10 million operating revolving letter of credit facility.

17. Asset Retirement Obligations

As at December 31		2021		2020
Balance, beginning of year	**$**	**379**	$	362
Obligations acquired *(note 3)*		**5**		13
New obligations		**4**		14
Obligations settled [(a)]		**(10)**		(4)
Disposals		**—**		(1)
Revision in estimated cash flow		**40**		(10)
Accretion expense [(b)]		**19**		17
Foreign exchange translation		**(1)**		(6)
Total	**$**	**436**	$	385
Less: current portion (included in accounts payable and accrued liabilities)		**(7)**		(6)
Balance, end of year	**$**	**429**	$	379

(a) During the year ended December 31, 2021, approximately $7 million of asset retirement obligations included in accounts payable and accrued liabilities were settled (December 31, 2020 - $6 million).

(b) Certain amounts relating to Utility asset retirement obligations are recorded through regulatory assets or liabilities on the Consolidated Balance Sheets due to regulatory treatment. The remaining portion is recorded through the Consolidated Statements of Income.

The majority of the asset retirement obligations are associated with distribution and transmission systems in the Utilities segment.

AltaGas estimates the undiscounted cash required to settle the asset retirement obligations, excluding growth for inflation, at December 31, 2021 was $892 million (December 31, 2020 - $868 million).

The asset retirement obligations have been recorded in the Consolidated Financial Statements at estimated values discounted at rates between 2.0 and 8.5 percent (December 31, 2020 - between 2.0 to 8.5 percent) and are expected to be incurred between 2022 and 2139 (December 31, 2020 - between 2021 and 2138). No assets have been legally restricted for settlement of the estimated liability.

18. Environmental Matters

AltaGas is subject to federal, provincial, state and local laws and regulations related to environmental matters. These laws and regulations may require expenditures over a long time frame to control environmental effects. Almost all of the environmental liabilities AltaGas has recorded are for costs expected to be incurred to remediate sites where AltaGas or a predecessor affiliate operated manufactured gas plants (MGPs). Estimates of liabilities for environmental response costs are difficult to determine with precision because of the various factors that can affect their ultimate level. These factors include, but are not limited to, the following:

- the complexity of the site;
- changes in environmental laws and regulations at the federal, state, and local levels;
- the number of regulatory agencies or other parties involved;
- new technology that renders previous technology obsolete or experience with existing technology that proves ineffective;
- the level of remediation required; and
- variations between the estimated and actual period of time that must be dedicated to respond to an environmentally-contaminated site.

AltaGas has identified up to twelve sites where it or its predecessors may have operated MGPs. In connection with these operations, AltaGas is aware that coal tar and certain other by-products of the gas manufacturing process are present at or near some former sites and may be present at others.

As at December 31, 2021, a liability of $18 million has been recorded on an undiscounted basis related to future environmental response costs (December 31, 2020 - $13 million) in the Consolidated Balance Sheets under the line items "accounts payable and accrued liabilities and other long-term liabilities". These estimates principally include the minimum liabilities associated with a range of environmental response costs expected to be incurred. As at December 31, 2021, AltaGas estimated the maximum liability associated with all of its sites to be approximately $50 million (December 31, 2020 - $39 million). The estimates were determined by AltaGas' environmental experts, based on experience in remediating MGP sites and advice from legal counsel and environmental consultants. The variation between the recorded and estimated maximum liability primarily results from differences in the number of years that will be required to perform environmental response processes and the extent of remediation that may be required.

As at December 31, 2021, AltaGas reported a regulatory asset of $16 million (December 31, 2020 - $15 million) for the portion of environmental response costs that are expected to be recoverable in future rates (Note 21).

19. Other Long-term Liabilities

As at	**December 31, 2021**	December 31, 2020
Deferred revenue	**$ 13**	$ 8
Customer advances for construction	**59**	60
Merger commitments	**7**	10
Non-retirement employee benefits	**19**	22
Deferred payroll taxes [(a)]	**—**	6
Petrogas equalization reserve [(b)]	**—**	5
Uncertain tax positions *(note 20)*	**20**	21
Other	**16**	21
	$ 134	$ 153

(a) Represented U.S. federal payroll tax deferrals from the Coronavirus Aid, Relief, and Economic Security (CARES) Act.

(b) Reserve was held by a wholly owned subsidiary of Petrogas.

20. Income Taxes

Year Ended December 31		2021		2020
Income before income taxes - consolidated	**$**	**446**	$	699
Statutory income tax rate (%)		**23.0**		24.0
Expected taxes at statutory rates	**$**	**103**	$	168
Add (deduct) the tax effect of:				
Permanent differences	**$**	**3**	$	2
Statutory and other rate differences		**25**		9
Deferred income tax recovery on regulated assets		**(18)**		(15)
Tax differences on divestitures and transactions		**(4)**		(33)
Change in valuation allowance		**—**		(2)
Other		**(3)**		(2)
	$	**106**	$	127
Income tax provision				
Current	**$**	**59**	$	1
Deferred		**47**		126
	$	**106**	$	127
Effective income tax rate (%)		**23.8**		18.2

Net deferred income tax liabilities were composed of the following:

As at		December 31, 2021		December 31, 2020
PP&E and intangible assets	**$**	**1,709**	$	1,645
Regulatory assets		**(233)**		(229)
Tax pools, deferred financing, and compensation		**(236)**		(208)
Other		**(84)**		(94)
Valuation allowance		**2**		4
	$	**1,158**	$	1,118

The amount shown on the Consolidated Balance Sheets as deferred income tax liabilities represents the net differences between the tax basis and book carrying values on the Corporation's balance sheets at enacted tax rates.

The Alberta government reduced Alberta's corporate tax rate from 11 percent to 8 percent on July 1, 2020.

As at December 31, 2021, the Corporation had tax-effected non-capital losses of approximately $331 million, which will be available to offset future taxable income. If not used, these losses will expire between 2027 and 2041.

Uncertain Tax Positions

The Corporation recognizes the benefit of an uncertain tax position only when it is more likely than not that such a position will be sustained by the taxing authorities based on the technical merits of the position. The current and deferred tax impact is equal to the largest amount, considering possible settlement outcomes, that has greater than 50 percent likelihood of being realized upon settlement with the taxing authorities.

On an annual basis, the Corporation and its subsidiaries file tax returns in Canada and various foreign jurisdictions. In Canada, AltaGas' federal and provincial tax returns for the years 2013 to 2020 remain subject to examination by taxation authorities. In the United States, both the federal and state tax returns for the years 2017 to 2020 remain subject to examination by the taxation authorities.

Management determined that the following provision was required for uncertainty on income taxes during the year:

Year ended December 31		2021		2020
Balance, beginning of year	**$**	**21**	$	2
Gross increases for tax positions of prior year		**—**		21
Lapses of statute of limitations		**—**		(2)
Settlement		**(1)**		—
Balance, end of year	**$**	**20**	$	21

21. Regulatory Assets and Liabilities

AltaGas accounts for certain transactions in accordance with ASC 980, Regulated Operations. AltaGas refers to this accounting guidance for regulated entities as "regulatory accounting". Under regulatory accounting, utilities are permitted to defer expenses and income as regulatory assets and liabilities, respectively, in the Consolidated Balance Sheets when it is probable that those expenses and income will be allowed in the rate-setting process in a period different from the period in which they would have been reflected in the Consolidated Statements of Income by a non-rate-regulated entity. These deferred regulatory assets and liabilities are included in the Consolidated Statements of Income in future periods when the amounts are reflected in customer rates. If an application is filed to modify customer rates with certain regulatory commissions, AltaGas is permitted to charge customers new rates, subject to refund, until the regulatory commission renders a final decision. During this interim period, a provision is recorded for a rate refund regulatory liability based on the difference between the amount collected in rates and the amount expected to be recovered from a final regulatory decision.

Management's assessment of the probability of recovery or pass-through of regulatory assets and liabilities requires judgment and interpretation of laws and regulatory agency orders, rules, and rate-making conventions. The relevant regulatory bodies are the MPSC, RCA, PSC of DC, PSC of MD, and SCC of VA.

If, for any reason, the Corporation ceases to meet the criteria for application of regulatory accounting for all or part of its operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be de-recognized from the Consolidated Balance Sheets and included in the Consolidated Statements of Income for the period in which the discontinuance of regulatory accounting occurs. Criteria that give rise to the discontinuance of regulatory accounting include: (i) increasing competition that restricts the ability of the Corporation to charge prices sufficient to recover specific costs, and (ii) a significant change in the manner in which rates are set by regulatory agencies from cost-based regulation to another form of regulation. The Corporation's review of these criteria currently supports the continued application of regulatory accounting for all its utilities.

The following table summarizes the regulatory assets and liabilities recorded in the Consolidated Balance Sheets, as well as the remaining period, as at December 31, 2021 and 2020, over which the Corporation expects to realize or settle the assets or liabilities:

As at December 31		2021		2020	Recovery Period
Regulatory assets - current					
Deferred cost of gas [(a)]	**$**	**20**	$	18	Less than one year
Accelerated replacement recovery mechanisms [(b)]		**7**		6	Less than one year
Interruptible sharing [(c)]		**—**		2	n/a
Energy optimization costs		**5**		1	Less than one year
Virginia and Maryland revenue normalization [(c)]		**16**		19	Less than one year
	$	**48**	$	46	
Regulatory assets - non-current					
Deferred regulatory costs [(c) (d)]	**$**	**199**	$	158	1 - 54 years
Future recovery of pension and other retirement benefits [(c)]		**33**		68	10 - 20 years
Future recovery of non-retirement employee benefits [(c) (e)]		**19**		22	Various
Deferred environmental costs [(c) (f)]		**16**		15	Various
Deferred loss on debt transactions and derivative instruments [(c) (g)]		**89**		93	Various
Deferred future income taxes [(c) (h)]		**43**		46	Various
Energy efficiency program - Maryland [(i)]		**23**		18	Various
COVID-19 costs [(j)]		**6**		10	Various
Other		**8**		14	Various
	$	**436**	$	444	
Regulatory liabilities - current					
Deferred cost of gas [(a)]	**$**	**71**	$	56	Less than one year
Refundable tax credit [(k)]		**2**		2	Less than one year
Federal income tax rate change [(l)]		**1**		20	Less than one year
Interruptible sharing [(c)]		**4**		1	Less than one year
Virginia Coronavirus Relief Fund [(m)]		**1**		10	Less than one year
Other		**—**		1	n/a
	$	**79**	$	90	
Regulatory liabilities - non-current					
Refundable tax credit [(k)]	**$**	**—**	$	2	n/a
Future expense of pension and other retirement benefits [(c)]		**425**		335	Various
Future removal and site restoration costs [(n)]		**453**		462	Various
Deferred gain on debt transactions and derivative instruments [(c) (g)]		**1**		1	Various
Federal income tax rate change [(l)]		**543**		578	Various
Other		**2**		3	Various
	$	**1,424**	$	1,381	

(a) Washington Gas is not entitled to a rate of return on these assets. Washington Gas is allowed to recover and required to pay, using short-term interest rates, the carrying costs related to billed gas costs due from and to its customers in the District of Columbia and Virginia jurisdictions.

(b) Represents amounts for deferred over or under collections of surcharges associated with Washington Gas' accelerated pipeline recovery programs in the District of Columbia, Maryland, and Virginia.

(c) Washington Gas is not entitled to a rate of return on these assets.

(d) Includes deferred gas costs and fair value of derivatives, which are not included in customer bills until settled.

(e) Represents the timing difference between the recognition of workers compensation and short-term disability costs in accordance with generally accepted accounting principles and the way these costs are recovered through rates.

(f) This balance represents allowed environmental remediation expenditures at SEMCO and Washington Gas sites to be recovered through rates.

(g) The losses or gains on the issuance and extinguishment of debt and interest-rate derivative instruments include unamortized balances from transactions executed in prior years. These transactions create gains and losses that are amortized over the remaining life of the debt as prescribed by regulatory accounting requirements. As at December 31, 2021, this also includes a fair value adjustment of $72 million (December 31, 2020 - $76 million) recorded on the WGL Acquisition in 2018.

(h) This balance represents amounts due from customers for deferred tax assets and liabilities related to tax benefits/expenses on deductions flowed directly to customers prior to the adoption of income tax normalizations for ratemaking purposes and to tax rate changes.

(i) Represents amounts for deferred credits associated with Washington Gas' participation in the energy conservation and efficiency program EmPower in Maryland.

(j) Regulatory assets established to capture and track incremental COVID-19 related costs.

(k) On September 18, 2013, CINGSA received a US$15 million gas storage facility tax credit from the State of Alaska for the benefit of its firm storage service customers. CINGSA acted as a custodian of the tax credit and any interest earned for the benefit of CINGSA's customers. On an annual basis from 2012 to 2021, CINGSA disbursed to the customers 1/10th of the amount of the tax credit not subject to refund to the State and interest earned.

(l) The *Tax Cuts and Jobs Act* (TCJA) was enacted on December 22, 2017, and required the Corporation to revalue its U.S. deferred tax assets and liabilities in 2018 to the lower federal corporate tax rate of 21 percent, resulting in excess accumulated deferred income taxes. The tax rate reduction created a reduction in deferred tax liability, which SEMCO Gas and Washington Gas are required to refund to ratepayers.

(m) The Virginia Coronavirus Relief Fund was received by WGL to provide direct assistance to Virginia customers with balances over 60 days in arrears.

(n) This amount and timing of draw down is dependent upon the cost of removal of the underlying utility property, plant and equipment and its useful life.

22. Accumulated Other Comprehensive Income (Loss)

($ millions)	Defined benefit pension and PRB plans	Hedge net investments	Translation foreign operations	Equity investee	Total
Opening balance, January 1, 2021	**$ (12)**	**$ (158)**	**$ 220**	**$ —**	**$ 50**
OCI before reclassification	**3**	**—**	**(61)**	**—**	**(58)**
Amounts reclassified from OCI	**3**	**—**	**—**	**—**	**3**
Current period OCI (pre-tax)	**$ 6**	**$ —**	**$ (61)**	**$ —**	**$ (55)**
Income tax on amounts retained in AOCI	**(1)**	**—**	**—**	**—**	**(1)**
Income tax on amounts reclassified to earnings	**(1)**	**—**	**—**	**—**	**(1)**
Net current period OCI	**$ 4**	**$ —**	**$ (61)**	**$ —**	**$ (57)**
Ending balance, December 31, 2021	**$ (8)**	**$ (158)**	**$ 159**	**$ —**	**$ (7)**
Opening balance, January 1, 2020	$ (6)	$ (149)	$ 395	$ 5	$ 245
OCI before reclassification	(11)	(10)	(175)	(5)	(201)
Amounts reclassified from OCI	3	—	—	—	3
Current period OCI (pre-tax)	$ (8)	$ (10)	$ (175)	$ (5)	$ (198)
Income tax on amounts retained in AOCI	3	1	—	—	4
Income tax on amounts reclassified to earnings	(1)	—	—	—	(1)
Net current period OCI	$ (6)	$ (9)	$ (175)	$ (5)	$ (195)
Ending balance, December 31, 2020	$ (12)	$ (158)	$ 220	$ —	$ 50

Reclassification From Accumulated Other Comprehensive Income

AOCI components reclassified	Income statement line item	**Year Ended December 31, 2021**	Year Ended December 31, 2020
Defined benefit pension and PRB plans	Other income	**$ 3**	$ 3
Deferred income taxes	Income tax expense – deferred	**(1)**	(1)
		$ 2	$ 2

23. 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 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 was calculated using quoted market rates.

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 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 and NGL, LPG, ocean freight, and 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	**December 31, 2021**				
	Carrying Amount	**Level 1**	**Level 2**	**Level 3**	**Total Fair Value**
Financial assets					
Fair value through net income [(a)]					
Risk management assets - current	**$ 112**	**$ —**	**$ 73**	**$ 39**	**$ 112**
Risk management assets - non-current	**50**	**—**	**22**	**28**	**50**
Fair value through regulatory assets [(a)]					
Risk management assets - current	**1**	**—**	**—**	**1**	**1**
Risk management assets - non-current	**1**	**—**	**—**	**1**	**1**
	$ 164	**$ —**	**$ 95**	**$ 69**	**$ 164**
Financial liabilities					
Fair value through net income [(a)]					
Risk management liabilities - current	**$ 113**	**$ —**	**$ 58**	**$ 55**	**$ 113**
Risk management liabilities - non-current	**90**	**—**	**11**	**79**	**90**
Fair value through regulatory liabilities [(a)]					
Risk management liabilities - current	**15**	**—**	**—**	**15**	**15**
Risk management liabilities - non-current	**75**	**—**	**—**	**75**	**75**
Amortized cost					
Current portion of long-term debt	**511**	**—**	**511**	**—**	**511**
Long-term debt	**7,684**	**—**	**7,898**		**7,898**
Other current liabilities [(b)]	**43**	**—**	**43**	**—**	**43**
	$ 8,531	**$ —**	**$ 8,521**	**$ 224**	**$ 8,745**

(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) Excludes non-financial liabilities.

As at	December 31, 2020				
	Carrying Amount	Level 1	Level 2	Level 3	Total Fair Value
Financial assets					
Fair value through net income [(a)]					
Risk management assets - current	$ 94	$ —	$ 73	$ 21	$ 94
Risk management assets - non-current	38	—	2	36	38
Fair value through regulatory assets [(a)]					
Risk management assets - current	4	—	1	3	4
Risk management assets - non-current	9	—	—	9	9
	$ 145	$ —	$ 76	$ 69	$ 145
Financial liabilities					
Fair value through net income [(a)]					
Risk management liabilities - current	$ 102	$ —	$ 78	$ 24	$ 102
Risk management liabilities - non-current	66	—	15	51	66
Fair value through regulatory liabilities [(a)]					
Risk management liabilities - current	9	—	—	9	9
Risk management liabilities - non-current	79	—	1	78	79
Amortized cost					
Current portion of long-term debt	360	—	360	—	360
Long-term debt	7,626	—	8,451	—	8,451
Other current liabilities [(b)]	37	—	37	—	37
	$ 8,279	$ —	$ 8,942	$ 162	$ 9,104

(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) Excludes non-financial liabilities.

Financial assets and liabilities not included in the fair value hierarchy table include money market funds, short term debt, and commercial paper. 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 as at December 31, 2021:

	Net Fair Value	Valuation Technique	Unobservable Inputs	Range	Weighted Average [(a)]
Natural gas	$ (106)	Discounted Cash Flow	Natural Gas Basis Price (per Dth)	$ (1.79) - $ 5.71	$ (0.51)
Natural gas	$ (1)	Option Model	Natural Gas Basis Price (per Dth)	$ (1.61) - $ 5.57	$ 0.39
			Annualized Volatility of Spot Market Natural Gas	14 % - 399 %	60 %
Electricity	$ (48)	Discounted Cash Flow	Electricity Congestion Price (per MWh)	$ (8.13) - $93.94	$ 18.37

(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:

For the year ended December 31	**2021**			2020		
	Natural Gas	**Electricity**	**Total**	Natural Gas	Electricity	Total
Balance, beginning of year	**$ (74)**	**$ (19)**	**$ (93)**	$ (85)	$ —	$ (85)
Realized and unrealized gains (losses):						
Recorded in income	**(15)**	**(25)**	**(40)**	8	(55)	(47)
Recorded in regulatory assets	**(28)**	**—**	**(28)**	(1)	—	(1)
Transfers into Level 3	**—**	**—**	**—**	(1)	—	(1)
Transfers out of Level 3	**(1)**	**—**	**(1)**	1	—	1
Purchases	**—**	**4**	**4**	—	3	3
Settlements	**14**	**(8)**	**6**	4	32	36
Foreign exchange translation	**(3)**	**—**	**(3)**	—	1	1
Balance, end of year	**$ (107)**	**$ (48)**	**$ (155)**	$ (74)	$ (19)	$ (93)

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 year ended December 31, 2021 were due to an increase in valuations using observable market inputs.

Realized and Unrealized Gains (Losses) Recorded to Income for Level 3 Measurements

Year Ended December 31	2021	2020
Recorded to revenue	$ (79)	$ (79)
Recorded to cost of sales	39	32
	$ (40)	$ (47)

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

Year Ended December 31	2021	2020
Natural gas	$ 6	$ 32
Energy exports	38	10
Crude oil and NGLs	1	4
NGL frac spread	(13)	(5)
Power	9	(15)
Foreign exchange	(23)	(5)
	$ 18	$ 21

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	December 31, 2021			
	Gross amounts of recognized assets/liabilities	Gross amounts offset in balance sheet	Netting of collateral	Net amounts presented in balance sheet
Risk management assets [(a)]				
Natural gas	$ 94	$ (22)	$ (25)	$ 47
Energy exports	61	(60)	37	38
NGL frac spread	4	—	—	4
Power	101	(25)	(1)	75
	$ 260	$ (107)	$ 11	$ 164
Risk management liabilities [(b)]				
Natural gas	$ 164	$ (22)	$ (4)	$ 138
Energy exports	81	(60)	2	23
Crude oil and condensates	6	—	2	8
NGL frac spread	23	—	—	23
Power	126	(25)	—	101
	$ 400	$ (107)	$ —	$ 293

(a) Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $113 million and risk management assets (non-current) balance of $51 million.

(b) Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $128 million and risk management liabilities (non-current) balance of $165 million.

As at	December 31, 2020			
	Gross amounts of recognized assets/liabilities	Gross amounts offset in balance sheet	Netting of collateral	Net amounts presented in balance sheet
Risk management assets [(a)]				
Natural gas	$ 104	$ (38)	$ (3)	$ 63
Energy exports	86	(86)	36	36
Crude oil and NGLs	1	—	—	1
Power	30	(8)	—	22
Foreign exchange	27	(3)	(1)	23
	$ 248	$ (135)	$ 32	$ 145
Risk management liabilities [(b)]				
Natural gas	$ 173	$ (38)	$ (3)	$ 132
Energy exports	153	(86)	—	67
NGL frac spread	6	—	—	6
Power	58	(8)	1	51
Foreign exchange	3	(3)	—	—
	$ 393	$ (135)	$ (2)	$ 256

(a) Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $98 million and risk management assets (non-current) balance of $47 million.

(b) Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $111 million and risk management liabilities (non-current) balance of $145 million.

Cash Collateral

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

As at	**December 31, 2021**	December 31, 2020
Collateral posted with counterparties	**$ 9**	$ 4
Cash collateral held representing an obligation	**$ 2**	$ —

Any collateral posted that is not offset against risk management assets and liabilities is included in 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 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 December 31, 2021 and December 31, 2020, 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	**December 31, 2021**	December 31, 2020
Risk management liabilities with credit-risk-contingent features	**$ 42**	$ 32
Maximum potential collateral requirements	**$ 21**	$ 26

Risks associated with financial instruments

AltaGas is exposed to various financial risks in the normal course of operations such as market risks resulting from fluctuations in commodity prices, currency exchange rates and interest rates as well as credit risk and liquidity risk.

Commodity Price Risk

AltaGas enters into financial derivative contracts to manage exposure to fluctuations in commodity prices. The use of derivative instruments is governed under formal risk management policies and is subject to parameters set out by AltaGas' Risk Management Committee and Board of Directors. AltaGas does not make use of derivative instruments for speculative purposes.

Natural Gas

In the normal course of business, AltaGas purchases and sells natural gas to support its infrastructure business. The fixed price and market price contracts for both the purchase and sale of natural gas extend to 2033. In addition, AltaGas may enter into financial derivative contracts as part of WGL's asset optimization program. WGL optimized the value of its long-term natural gas transportation and storage capacity resources during periods when these resources are not being used to physically serve utility customers.

AltaGas had the following forward contracts and commodity swaps outstanding related to the activities in the energy services business as at December 31, 2021 and 2020:

December 31, 2021	**Fixed price (per GJ)**	**Period (months)**	**Notional volume (GJ)**		**Fair Value**
Sales	**1.75 to 10.8**	**1-142**	**259,750,059**	**$**	**(8)**
Purchases	**1.75 to 10.8**	**1-143**	**606,923,548**	**$**	**(102)**
Swaps	**2.95 to 7.42**	**1-55**	**201,266,412**	**$**	**19**

December 31, 2020	Fixed price (per GJ)	Period (months)	Notional volume (GJ)		Fair Value
Sales	1.58 to 7.86	1-157	590,054,996	$	32
Purchases	1.58 to 6.47	1-240	1,522,958,497	$	(106)
Swaps	2.29 to 7.86	1-60	288,613,586	$	5

Crude Oil and NGLs

In the normal course of business, AltaGas utilizes financial swaps to manage the impact of timing between when product is purchased and solid in addition to differing indices on purchase and sales.

December 31, 2021	**Fixed price (per Bbl)**	**Period (months)**	**Notional volume (Bbl)**		**Fair Value**
Swaps	**41.18 to 97.12**	**1-12**	**864,000**	**$**	**(8)**

December 31, 2020	Fixed price (per Bbl)	Period (months)	Notional volume (Bbl)		Fair Value
Swaps	19.92 to 62.59	1-9	901,000	$	1

Energy Exports

AltaGas entered into a series of swaps to lock in a portion of the volumes exposed to the propane and butane price differentials between North American Indices and the Far East Index for contracts not under tolling arrangements at RIPET and Ferndale. AltaGas had the following contracts outstanding as at December 31, 2021:

December 31, 2021	**Fixed price (per Bbl)**	**Period (months)**	**Notional volume (Bbl)**		**Fair Value**
Propane and butane swaps	**5.2 to 115.54**	**1-15**	**38,860,780**	**$**	**15**

December 31, 2020	Fixed price (per Bbl)	Period (months)	Notional volume (Bbl)		Fair Value
Propane and butane swaps	3.57 to 61.46	1-36	37,425,488	$	(31)

NGL Frac Spread

AltaGas entered into a series of swaps to lock in a portion of the volumes exposed to NGL frac spread. AltaGas had the following contracts outstanding as at December 31, 2021 and 2020:

December 31, 2021	**Fixed price**	**Period (months)**	**Notional volume**		**Fair Value**
Propane swaps	**33.14 to 59.75/Bbl**	**1-12**	**2,099,243**	**Bbl $**	**(15)**
Butane swaps	**36.19 to 36.20/Bbl**	**1-3**	**18,967**	**Bbl $**	**(1)**
Crude oil swaps	**63.25 to 89.86/Bbl**	**1-12**	**369,495**	**Bbl $**	**(4)**
Natural gas swaps	**2.54 to 3.89/GJ**	**1-12**	**11,873,390**	**GJ $**	**1**

December 31, 2020	Fixed price	Period (months)	Notional volume		Fair Value
Propane swaps	28.83 to 35.36/Bbl	1-12	1,270,350	Bbl $	(5)
Butane swaps	32.45 to 34.02/Bbl	1-12	307,784	Bbl $	(1)
Crude oil swaps	60.08 to 61.95/Bbl	1-12	123,120	Bbl $	—
Natural gas swaps	1.58 to 1.86/GJ	1-12	7,281,570	GJ $	—

Power

AltaGas sells power to the Alberta Electric System Operator at market prices. AltaGas also sells power through its WGL Energy Services affiliate, to commercial, industrial and mass market users within the PJM Regional Transmission Organization at fixed and market prices. AltaGas' strategy is to mitigate the cash flow risk to power prices to provide predictable earnings. Therefore, AltaGas uses third-party swaps and purchase contracts to fix the prices over time on a portion of the volumes to mitigate financial exposure associated with the sale contracts. These power purchase and sale contracts extend to 2026. As at December 31, 2021, AltaGas had no intention to terminate any contracts prior to maturity. AltaGas had the following power commodity forward contracts and commodity swaps outstanding as at December 31, 2021 and 2020:

December 31, 2021	**Fixed price (per MWh)**	**Period (months)**	**Notional volume (MWh)**		**Fair Value**
Power sales	**27.19 to 93.94**	**1-42**	**4,938,045**	**$**	**(60)**
Power purchases	**27.19 to 93.94**	**1-53**	**6,393,003**	**$**	**69**
Swap purchases	**(8.13) to 86.84**	**1-41**	**22,845,569**	**$**	**(35)**

December 31, 2020	Fixed price (per MWh)	Period (months)	Notional volume (MWh)		Fair Value
Power sales	24.56 to 61.75	1-33	5,482,242	$	13
Power purchases	24.56 to 61.88	1-63	8,848,007	$	(18)
Swap purchases	(6.26) to 74.26	1-44	24,081,519	$	(24)

The table below provides the potential impact on pre-tax income due to changes in the fair value of risk management contracts in place as at December 31, 2021:

Factor	Increase or decrease to forward prices	Increase or decrease to income before tax ($ millions)
PJM power price	US$1/MWh	1
NYMEX natural gas price	US$0.50/GJ	39
Energy Exports:		
Propane Far East Index to domestic supply	$1/Bbl	(9)
Baltic LPG Freight	$1/Bbl	5
NGL frac spread:		
Natural gas	$0.50/GJ	6

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 and/or preferred shares outstanding. AltaGas may also enter into foreign exchange forward derivatives to manage the risk of fluctuating cash flows due to variations in foreign exchange rates.

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 transaction gain or loss as a net investment hedge of its U.S. subsidiaries. As at December 31, 2021, AltaGas has designated US$122 million of outstanding loans as a net investment hedge (December 31, 2020 - $nil). For the year ended December 31, 2021, no after-tax unrealized gains or losses were recorded related to the translation of debt in OCI (2020 - after-tax unrealized loss of $9 million).

The following foreign exchange forward contracts were outstanding as at December 31, 2021:

Foreign exchange forward contract	Notional Amount *(US$ millions)*	Duration	Weighted average foreign exchange rate	Fair Value
Foreign exchange swaps (purchases)	**US$10**	**Less than one year**	**1.2640**	**Less than $1 million**

The following foreign exchange forward contracts were outstanding as at December 31, 2020:

Foreign exchange forward contract	Notional Amount *(US$ millions)*	Duration	Weighted average foreign exchange rate	Fair Value
Forward USD sales	US$29	Less than one year	1.3591	$ 3
Forward USD purchases	US$356	Less than one year	1.2824	$ (3)
Foreign exchange swaps (sales)	US$410	Less than one year	1.3322	$ 23

For the year ended December 31, 2021, AltaGas recorded an after-tax realized gain of $19 million on all foreign exchange forward contracts (2020 - $1 million).

Interest Rate Risk

AltaGas is exposed to interest rate risk as changes in interest rates may impact future cash flows and the fair value of its financial instruments. The Corporation manages its interest rate risk by holding a mix of both fixed and floating interest rate debt. As at December 31, 2021, approximately 87 percent of AltaGas' total outstanding short-term and long-term debt was at fixed rates (December 31, 2020 - 83 percent). In addition, from time to time, AltaGas may enter into interest rate swap agreements to fix the interest rate on a portion of its banker's acceptances issued under its credit facilities. There were no outstanding interest rate swaps as at December 31, 2021.

Credit Risk

Credit risk results from the possibility that a counterparty to a financial instrument fails to fulfill its obligations in accordance with the terms of the contract.

AltaGas' credit policy details the parameters used to grant, measure, monitor and report on credit provided to counterparties. AltaGas minimizes counterparty risk by conducting credit reviews on counterparties in order to establish specific credit limits, both prior to providing products or services and on a recurring basis. In addition, most contracts include credit mitigation clauses that allow AltaGas to obtain financial or performance assurances from counterparties under certain circumstances. AltaGas maintains an allowance for doubtful accounts in the normal course of its business.

AltaGas' maximum credit exposure consists primarily of the carrying value of the non-derivative financial assets and the fair value of derivative financial assets. As at December 31, 2021, AltaGas had no concentration of credit risk with a single counterparty.

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 year ended December 31, 2021, a pre-tax loss of less than $1 million was recorded related to these instruments (2020 - pre-tax loss of $3 million).

Accounts Receivable Past Due or Impaired

With the exception of accounts receivable which are due in one year or less as summarized in the following table, AltaGas does not have any past due or impaired accounts receivable (AR) as at December 31, 2021:

As at December 31, 2021	Total	AR accruals	Receivables impaired	Less than 30 days	31 to 60 days	61 to 90 days	Over 90 days
Trade receivable	$ 1,431	$ 560	$ 39	$ 703	$ 52	$ 24	$ 53
Other	35	—	—	35	—	—	—
Allowance for credit losses	(39)	—	(39)	—	—	—	—
	$ 1,427	$ 560	$ —	$ 738	$ 52	$ 24	$ 53

As at December 31, 2020		Total	AR accruals	Receivables impaired	Less than 30 days	31 to 60 days	61 to 90 days	Over 90 days
Trade receivable	$	1,465	$ 396	$ 41	$ 906	$ 52	$ 17	$ 53
Other		20	—	—	20	—	—	—
Allowance for credit losses		(41)	—	(41)	—	—	—	—
	$	1,444	$ 396	$ —	$ 926	$ 52	$ 17	$ 53

The following table provides a summary of changes to the allowance for credit losses by segment and major type:

	Year Ended December 31, 2021			
	Accounts Receivable	**Contract Assets [a]**	**Other long-term investments and other assets**	**Total**
Utilities				
Balance, beginning of period	**$ 40**	**$ —**	**$ —**	**$ 40**
Adjustments to allowance [b]	**15**	**—**	**—**	**15**
Written off	**(22)**	**—**	**—**	**(22)**
Recoveries collected	**5**	**—**	**—**	**5**
Balance, end of period	**$ 38**	**$ —**	**$ —**	**$ 38**
Midstream				
Balance, beginning of period	**$ 1**	**$ 1**	**$ 2**	**$ 4**
New allowance	**—**	**—**	**(2)**	**(2)**
Balance, end of period	**$ 1**	**$ 1**	**$ —**	**$ 2**
Total	**$ 39**	**$ 1**	**$ —**	**$ 40**

(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 $5 million recorded to a regulatory asset relating to the impact of COVID-19 on uncollectible accounts.

	Year Ended December 31, 2020			
	Accounts Receivable	Contract Assets (a)	Other long-term investments and other assets (b)	Total
Utilities				
Balance, beginning of period	$ 31	$ —	$ —	$ 31
Adjustment upon adoption of ASC 326 (c)	2	—	—	2
Foreign exchange translation	(1)	—	—	(1)
New allowance (d)	32	—	—	32
Written off	(28)	—	—	(28)
Recoveries collected	4	—	—	4
Balance, end of period	$ 40	$ —	$ —	$ 40
Midstream				
Balance, beginning of period	$ 1	$ —	$ —	$ 1
Adjustment upon adoption of ASC 326	—	1	3	4
Recoveries collected	—	—	(1)	(1)
Balance, end of period	$ 1	$ 1	$ 2	$ 4
Corporate/Other				
Balance, beginning of period	$ 2	$ —	$ —	$ 2
Adjustment upon adoption of ASC 326	—	—	1	1
Written off	(2)	—	—	(2)
Recoveries collected	—	—	(1)	(1)
Balance, end of period	$ —	$ —	$ —	$ —
Total	$ 41	$ 1	$ 2	$ 44

(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 loan to affiliate, which is no longer outstanding at December 31, 2020, and other long-term receivables. 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 commensurate with the period in which the receivable is expected to be collected.

(c) Based on previous collection experience, AltaGas did not record an allowance for credit losses for its contract assets associated with its energy management services projects with the U.S. federal government.

(d) Includes $8 million recorded to a regulatory asset relating to the impact of COVID-19 on uncollectible accounts.

Liquidity Risk

Liquidity risk is the risk that AltaGas will not be able to meet its financial obligations as they come due. AltaGas manages this risk through its extensive budgeting and monitoring process to ensure it has sufficient cash and credit facilities to meet its obligations. AltaGas' objective is to maintain its investment-grade ratings to ensure it has access to debt and equity funding as required.

AltaGas had the following contractual maturities with respect to financial liabilities:

		Contractual maturities by period			
As at December 31, 2021	**Total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**After 5 years**
Accounts payable and accrued liabilities	**$ 1,544**	**$ 1,544**	**$ —**	**$ —**	**$ —**
Short-term debt	**169**	**169**	**—**	**—**	**—**
Other current liabilities [(a)]	**43**	**43**	**—**	**—**	**—**
Risk management contract liabilities	**293**	**128**	**85**	**25**	**55**
Current portion of long-term debt [(b)]	**506**	**506**	**—**	**—**	**—**
Long-term debt [(b)]	**7,639**	**—**	**1,356**	**1,775**	**4,508**
	$ 10,194	**$ 2,390**	**$ 1,441**	**$ 1,800**	**$ 4,563**

(a) Excludes non-financial liabilities.

(b) Excludes deferred financing costs, discounts, finance lease liabilities, and the fair value adjustment on the WGL Acquisition.

		Contractual maturities by period			
As at December 31, 2020	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Accounts payable and accrued liabilities	$ 1,561	$ 1,561	$ —	$ —	$ —
Dividends payable	22	22	—	—	—
Short-term debt	256	256	—	—	—
Other current liabilities [(a)]	37	37	—	—	—
Risk management contract liabilities	256	111	51	22	72
Current portion of long-term debt [(b)]	356	356	—	—	—
Long-term debt [(b)]	7,581	—	1,771	1,324	4,486
	$ 10,069	$ 2,343	$ 1,822	$ 1,346	$ 4,558

(a) Excludes non-financial liabilities.

(b) Excludes deferred financing costs, discounts, finance lease liabilities, and the fair value adjustment on the WGL Acquisition.

24. Revenue

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

	Year Ended December 31, 2021			
	Utilities	Midstream	Corporate/ Other	Total
Revenue from contracts with customers				
Commodity sales contracts	$ 1,316	$ 4,667	$ 1	$ 5,984
Midstream service contracts	—	1,664	—	1,664
Gas sales and transportation services	2,582	—	—	2,582
Storage services	24	—	—	24
Other	8	—	4	12
Total revenue from contracts with customers	$ 3,930	$ 6,331	$ 5	$ 10,266
Other sources of revenue				
Revenue from alternative revenue programs [(a)]	$ 92	$ —	$ —	$ 92
Leasing revenue [(b)]	—	168	102	270
Risk management and trading activities [(c) (d)]	(74)	12	(4)	(66)
Other	(12)	22	1	11
Total revenue from other sources	$ 6	$ 202	$ 99	$ 307
Total revenue	$ 3,936	$ 6,533	$ 104	$ 10,573

(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' gas facilities is accounted for as operating leases. For the Corporate/Other segment, a significant amount of revenue earned is through power purchase agreements which are accounted for as operating leases.

(c) Risk management activities involve the use of derivative instruments such as physical and financial swaps, forward contracts, and options. 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.

(d) WGL Midstream trading margins are reported in risk management and trading activities from the Midstream segment. Prior to the sale of the majority of WGL Midstream's commodity business in the second quarter of 2021, WGL Midstream entered into derivative contracts for the purpose of optimizing its storage and transportation capacity as well as managing the transportation and storage assets on behalf of third parties. The trading margins of WGL Midstream, including unrealized gains and losses on derivative instruments, are netted within revenues. Gross revenues for the year ended December 31, 2021 of $172 million associated with the GAIL Global (USA) LNG LLC (GAIL) contract and an Asset Management Agreement (AMA), which are in scope of ASC 606, are reported within risk management and trading activities. While the GAIL contract and AMA are individually not accounted for as derivatives, they are inseparable from the overall trading portfolio. Revenue from the GAIL contract is recognized 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. The GAIL contract had a term of 20 years and began on March 31, 2018. Revenue from the AMA is recognized based on the amount WGL Midstream has the right to invoice the customer in accordance with ASC 606. WGL executed the AMA in April 2020. AltaGas completed the sale of the majority of WGL Midstream's commodity business, including the GAIL contract and the AMA, in April 2021.

		Year Ended December 31, 2020		
	Utilities	Midstream	Corporate/ Other	Total
Revenue from contracts with customers				
Commodity sales contracts	$ 1,338	$ 1,097	$ 1	$ 2,436
Midstream service contracts	—	277	—	277
Gas sales and transportation services	2,394	—	—	2,394
Storage services	25	—	—	25
Other	9	—	20	29
Total revenue from contracts with customers	$ 3,766	$ 1,374	$ 21	$ 5,161
Other sources of revenue				
Revenue from alternative revenue programs [(a)]	$ 96	$ —	$ —	$ 96
Leasing revenue [(b)]	1	139	100	240
Risk management and trading activities [(c) (d)]	(31)	112	—	81
Other	(15)	10	14	9
Total revenue from other sources	$ 51	$ 261	$ 114	$ 426
Total revenue	$ 3,817	$ 1,635	$ 135	$ 5,587

(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' gas facilities is accounted for as operating leases. For the Corporate/Other segment, a significant amount of revenue earned is through power purchase agreements which are accounted for as operating leases.

(c) Risk management activities involve the use of derivative instruments such as physical and financial swaps, forward contracts, and options. 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.

(d) WGL Midstream trading margins are reported in risk management and trading activities from the Midstream segment. Prior to the sale of the majority of WGL Midstream's commodity business in the second quarter of 2021, WGL Midstream entered into derivative contracts for the purpose of optimizing its storage and transportation capacity as well as managing the transportation and storage assets on behalf of third parties. The trading margins of WGL Midstream, including unrealized gains and losses on derivative instruments, are netted within revenues. Gross revenues for the year ended December 31, 2020 of $437 million associated with the GAIL contract and an AMA, which are in scope of ASC 606, are reported within risk management and trading activities. While the GAIL contract and AMA are individually not accounted for as derivatives, they are inseparable from the overall trading portfolio. Revenue from the GAIL contract is recognized 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. The GAIL contract had a term of 20 years and began on March 31, 2018. Revenue from the AMA is recognized based on the amount WGL Midstream has the right to invoice the customer in accordance with ASC 606. WGL executed the AMA in April 2020. AltaGas completed the sale of the majority of WGL Midstream's commodity business, including the GAIL contract and the AMA, in April 2021.

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.

Gas Storage Services

Gas storage customers are billed monthly for services provided. Customer billings are based on four components: (i) reservation charges; (ii) capacity charges; (iii) injection/withdrawal charges; and (iv) excess charges. Reservation charges are based on the customer's contract withdrawal quantity, capacity charges are based on the customer's total contract quantity, and injection/withdrawal charges are based on the volume of gas delivered to or from the customer. Excess charges are applied to each day that the storage quantity exceeds 100 percent of the customer's maximum storage quantity. Revenue is recognized as the service has been performed over time on a monthly basis, which corresponds to the invoice amount. The majority of these contracts have terms extending beyond one year.

Commodity Sales

Commodity sales also include gas 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 gas 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. Petrogas' 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.

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.

Petrogas' 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 power purchase agreements which are accounted for as operating leases. In instances where power generation is not sold under a power purchase agreement, the commodity is sold 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 lease, 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.

Contract Balances

As at December 31, 2021, a contract asset of $42 million ($41 million net of credit losses) has been recorded within long-term investments and other assets on the Consolidated Balance Sheets (December 31, 2020 – $50 million net of credit losses). This contract asset represents the difference in revenue recognized under a new rate in a blend-and-extend contract modification with a customer. Revenue from this contract modification was recognized at the pre-modification rate until December 31, 2020, with the excess revenue recorded as a contract asset. The contract asset will be drawn down over the remaining term of the modified contract.

In addition, at December 31, 2021, there is a contract asset of $13 million (December 31, 2020 - $21 million) recorded within prepaid expenses and other current assets on the Consolidated Balance Sheets for WGL Energy Systems' unbilled revenue relating to design-build construction contracts. The contract asset represents unbilled amounts typically resulting from sales under contracts when the cost-to-cost method of revenue recognition is utilized, and revenue recognized exceeds the amount billed to the customer. Right to payment is achieved when the projects are formally "accepted" by the federal government. At December 31, 2021, contract liabilities of $1 million (December 31, 2020 - $nil) have been recorded within other current liabilities on the Consolidated Balance Sheets. The contract liabilities consisted of advance payments and billings in excess of revenue recognized and deferred revenue. Contract assets and liabilities are reported in a net position on a contract-by-contract basis at the end of each reporting period.

Contract Assets

As at		December 31, 2021		December 31, 2020
Balance, beginning of year	**$**	**71**	$	89
Additions		**—**		30
Amortization [(a)]		**(4)**		—
Transfers to accounts receivable [(b)]		**(13)**		(49)
Foreign exchange translation		**—**		1
Balance, end of year	**$**	**54**	$	71

(a) Represents the drawdown of a contract asset under a blend-and-extend contract modification.
(b) Amounts included in contract assets are transferred to accounts receivable when AltaGas' right to consideration becomes unconditional.

Contract Liabilities

As at		December 31, 2021		December 31, 2020
Balance, beginning of year	**$**	**—**	$	2
Additions		**1**		2
Revenue recognized from contract liabilities [(a)]		**—**		(4)
Balance, end of year	**$**	**1**	$	—

(a) Recognition of revenue related to performance obligations satisfied in the current period for amounts that were previously included in contract liabilities.

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 December 31, 2021:

		2022		2023		2024		2025		2026		2027 & beyond		Total
Midstream service contracts	$	136	$	133	$	133	$	130	$	127	$	954	**$**	**1,613**
Storage services		23		23		23		23		23		121		**236**
Other		2		2		2		2		2		7		**17**
	$	161	$	158	$	158	$	155	$	152	$	1,082	**$**	**1,866**

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.

25. 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.

Dividend Reinvestment and Optional Cash Purchase Plan (DRIP or the Plan)

The Plan consisted of two components: a Dividend Reinvestment component and an Optional Cash Purchase component. The Premium Dividend™ component of the plan was suspended in December 2018. The Dividend Reinvestment and Optional Cash Purchase component was suspended in December 2019, with the December dividend (paid January 2020) being the last dividend payment eligible for reinvestment by participating shareholders under the DRIP. The Plan in its entirety will remain suspended until further notice.

Common Shares Issued and Outstanding	Number of shares		Amount
January 1, 2020	279,074,685	$	6,719
Shares issued for cash on exercise of options	88,082		1
Deferred taxes on share issuance cost	—		(3)
Shares issued under DRIP	331,532		6
December 31, 2020	279,494,299	$	6,723
Shares issued for cash on exercise of options	774,739		15
Deferred taxes on share issuance cost	—		(3)
Issued and outstanding at December 31, 2021	**280,269,038**	**$**	**6,735**

Preferred Shares

As at	**December 31, 2021**			December 31, 2020		
Issued and Outstanding	**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 C	**8,000,000**		**206**	8,000,000		206
Series E	**8,000,000**		**200**	8,000,000		200
Series G	**6,885,823**		**172**	6,885,823		172
Series H	**1,114,177**		**28**	1,114,177		28
Series K	**12,000,000**		**300**	12,000,000		300
Share issuance costs, net of taxes			**(30)**			(29)
	44,000,000	**$**	**1,076**	44,000,000	$	1,077

On December 31, 2020, all outstanding Series I shares were redeemed. No gain or loss was recognized upon redemption.

The following table outlines the characteristics of the cumulative redeemable preferred shares [(a)]:

	Current yield	Annual dividend per share[(b)]	Redemption price per share [(g)]	Redemption and conversion option date[(c)(g)]	Right to convert into[(d)]
Series A [(e)]	3.060 %	$0.76500	$25	September 30, 2025	Series B
Series B [(f) (g)]	Floating	Floating	$25	September 30, 2025	Series A
Series C [(h)]	5.290 %	US$1.32250	US$25	September 30, 2022	Series D
Series E [(e)]	5.393 %	$1.34825	$25	December 31, 2023	Series F
Series G [(e)]	4.240 %	$1.06050	$25	September 30, 2024	Series H
Series H [(f) (g)]	Floating	Floating	$25	September 30, 2024	Series G
Series K	5.000 %	$1.25000	$25	March 31, 2022	n/a [(c)]

(a) This table only includes those series of preferred shares that are currently issued and outstanding. The Corporation is authorized to issue up to 8,000,000 of each of Series D Shares, Series F Shares, subject to certain conditions, upon conversion by the holders of the applicable currently issued and outstanding series of preferred shares noted opposite such series in the table on the applicable conversion option date. If issued upon the conversion of the applicable series of preferred shares, Series F Shares are also redeemable for $25.50 and Series D Shares are redeemable for US$25.50 on any date after the applicable conversion option date, plus all accrued but unpaid dividends to, but excluding, the date fixed for redemption.

(b) The holders of Series A Shares, Series C Shares, Series E Shares, Series G Shares, and Series K Shares are entitled to receive a cumulative quarterly fixed dividend as and when declared by the Board of Directors. The holders of Series B Shares and Series H Shares are entitled to receive a quarterly floating dividend as and when declared by the Board of Directors. If issued upon the conversion of the applicable series of Preferred Shares, the holders of Series D Shares and Series F Shares will be entitled to receive a quarterly floating dividend as and when declared by the Board of Directors.

(c) AltaGas may, at its option, redeem all or a portion of the outstanding shares for the redemption price per share, plus all accrued and unpaid dividends on the applicable redemption option date and on every fifth anniversary thereafter. On February 16, 2022, Series K holders received formal notice that all outstanding Series K preferred shares will be redeemed on March 31, 2022.

(d) The holder will have the right, subject to certain conditions, to convert their preferred shares of a specified series into Preferred Shares of that other specified series as noted in this column of the table on the applicable conversion option date and every fifth anniversary thereafter.

(e) Holders of Series A Shares, Series E Shares, and Series G Shares will be entitled to receive cumulative quarterly fixed dividends, which will reset on the redemption and conversion option date and every fifth year thereafter, at a rate equal to the sum of the then five-year Government of Canada bond yield plus 2.66 percent (Series A Shares), 3.17 percent (Series E Shares), and 3.06 percent (Series G Shares).

(f) Holders of Series B Shares and Series H Shares will be entitled to receive cumulative quarterly floating dividends, which will reset each quarter thereafter at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill rate plus 2.66 percent (Series B Shares) and 3.06 percent (Series H Shares). Each quarterly dividend is calculated as the annualized amount multiplied by the number of days in the quarter, divided by the number of days in the year. Commencing December 31, 2021, the floating quarterly dividend rate is $0.17192 per share for Series B Shares and $0.196582 per share for Series H Shares for the period starting December 31, 2021 to, but excluding, March 31, 2022.

(g) Series B Shares can be redeemed for $25.50 per share on any date after September 30, 2015 that is not a Series B conversion date, plus all accrued and unpaid dividends to, but excluding, the date fixed for redemption. Series H Shares can be redeemed for $25.50 per share on any date after September 30, 2019 that is not a Series H conversion date, plus all accrued and unpaid dividends to, but excluding, the date fixed for redemption.

(h) Holders of Series C Shares will be entitled to receive cumulative quarterly fixed dividends, which will reset on the redeemable and conversion option date and every fifth year thereafter, at a rate equal to the sum of the five-year U.S. Government bond yield plus 3.58 percent.

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 December 31, 2021, 12,976,162 shares were reserved for issuance under the plan.

As at December 31, 2021, share options granted under the plan have a term between six and ten years until expiry and vest no longer than over a four-year period.

As at December 31, 2021, the unexpensed fair value of share option compensation cost associated with future periods was $3 million (December 31, 2020 - $4 million).

The following table summarizes information about the Corporation's share options:

As at	December 31, 2021 Options outstanding		December 31, 2020 Options outstanding	
	Number of options	**Exercise price [(a)]**	Number of options	Exercise price [(a)]
Share options outstanding, beginning of year	**8,362,211**	**$ 21.06**	7,043,956	$ 22.49
Granted	**1,878,670**	**18.77**	2,501,755	19.46
Exercised	**(774,739)**	**17.44**	(88,082)	14.89
Forfeited	**(214,259)**	**25.24**	(631,549)	26.00
Expired	**(572,375)**	**33.26**	(463,869)	27.69
Share options outstanding, end of year	**8,679,508**	**$ 19.98**	8,362,211	$ 21.06
Share options exercisable, end of year	**4,435,287**	**$ 20.72**	3,607,391	$ 23.59

(a) Weighted average.

As at December 31, 2021, the aggregate intrinsic value of the total share options exercisable was $33 million (December 31, 2020 - $5 million), the total intrinsic value of share options outstanding was $68 million (December 31, 2020 - $9 million) and the total intrinsic value of share options exercised was $5 million (December 31, 2020 - less than $1 million).

The following table summarizes the employee share option plan as at December 31, 2021:

	Options outstanding			Options exercisable		
	Number outstanding	Weighted average exercise price	Weighted average remaining contractual life (years)	Number exercisable	Weighted average exercise price	Weighted average remaining contractual life (years)
$14.52 to $18.00	2,055,551	$ 15.31	3.08	1,821,156	$ 15.07	3.03
$18.01 to $25.08	5,325,569	19.29	4.22	1,396,838	19.60	3.68
$25.09 to $37.86	1,298,388	30.21	1.36	1,217,293	30.48	1.28
	8,679,508	**$ 19.98**	**3.52**	**4,435,287**	**$ 20.72**	**2.75**

The fair value of each option granted is estimated on the date of grant using the Black-Scholes-Merton option pricing model. The weighted average grant date fair value and assumptions are as follows:

Year ended December 31	**2021**	2020
Fair value per options ($)	**3.37**	2.61
Risk-free interest rate (%)	**0.42**	1.54
Expected life (years)	**6**	6
Expected volatility (%)	**35.70**	25.40
Annual dividend per share ($) [(a)]	**1.00**	0.96
Forfeiture rate (%)	**—**	—

(a) Annual dividend per share is calculated based on a weighted average share price and forward dividend yields as the grant dates.

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 36 months from the grant date. In addition, AltaGas has a DSUP, pursuant to which directors receive deferred share units (DSUs). 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)*	**2021**	2020
Balance, beginning of year	**5,732,134**	6,484,831
Granted	**1,405,190**	1,158,547
Vested and paid out	**(3,495,702)**	(681,841)
Forfeited	**(313,621)**	(1,342,832)
Units in lieu of dividends	**126,250**	113,429
Additional units added by performance factor	**28,889**	—
Outstanding, end of year	**3,483,140**	5,732,134

For the year ended December 31, 2021, the compensation expense recorded for the Phantom Plan and DSUP was $66 million (2020 – $16 million). As at December 31, 2021, the unrecognized compensation expense relating to the remaining vesting period for the Phantom Plan was $16 million (December 31, 2020 - $23 million) and is expected to be recognized over the vesting period.

26. Net Income Per Common Share

The following table summarizes the computation of net income per common share:

		Year Ended December 31		
		2021		2020
Numerator:				
Net income applicable to controlling interests	**$**	**283**	$	552
Less: Preferred share dividends		**(53)**		(66)
Net income applicable to common shares	**$**	**230**	$	486
Denominator:				
(millions of shares)				
Weighted average number of common shares outstanding		**279.9**		279.4
Dilutive equity instruments [(a)]		**1.8**		0.3
Weighted average number of common shares outstanding - diluted		**281.7**		279.7
Basic net income per common share	**$**	**0.82**	$	1.74
Diluted net income per common share	**$**	**0.82**	$	1.74

(a) Determined using the treasury stock method.

For the year ended December 31, 2021, 1.7 million share options (2020 – 7.0 million) were excluded from the diluted net income per share calculation as their effects were anti-dilutive.

27. Other Income

Year Ended December 31		**2021**		2020
Gains on asset sales *(note 4)*	**$**	**6**	$	223
Gain on remeasurement of previously held interest in AIJVLP *(note 3)*		**—**		22
Other components of net benefit cost *(note 28)*		**64**		52
Interest income and other revenue		**11**		9
Total	**$**	**81**	$	306

28. 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.

Defined Contribution Plan

AltaGas has a defined contribution (DC) pension plan for substantially all employees. The pension cost recorded for the DC plan was $22 million for the year ended December 31, 2021 (2020 - $21 million).

Defined Benefit Plans

AltaGas has several defined benefit pension plans for unionized and non-unionized employees, including one in Canada (which is comprised of five divisions) and five in the United States. The plans in the United States include a qualified, trusteed, non-contributory defined benefit pension plan, and a non-funded defined benefit restoration plan maintained by Washington Gas.

The defined benefit plans are partially funded except for three of the divisions in Canada and two plans in the United States which are fully funded.

AltaGas' most recent actuarial valuation of the Canadian defined benefit plan for funding purposes was completed for the year ended December 31, 2019. AltaGas is required to file an actuarial valuation of its Canadian defined benefit plan with the pension regulators at least every three years. The next actuarial valuation for funding purposes is required to be completed as of a date no later than December 31, 2022, and will be filed with the pension regulators in 2023. Actuarial valuations for funding purposes are required annually for AltaGas' U.S. defined benefit plans.

AltaGas plans to wind-up the Canadian defined benefit plan in 2022. As the decision to wind-up the plan was made in 2021, a curtailment of less than $1 million was recorded to AOCI for the year ended December 31, 2021.

Supplemental Executive Retirement Plans (SERP)

AltaGas has non-registered defined benefit plans that provide defined benefit pension benefits to eligible executives based on average earnings, years of service and age at retirement. The SERP benefits will be paid from the general revenue of the Corporation as payments come due or from the Rabbi Trusts funded as part of the WGL acquisition. Security will be provided for the SERP benefits through a letter of credit within a retirement compensation arrangement trust account.

Several executive officers of Washington Gas participate in a separate non-funded defined benefit SERP (a non-qualified pension plan). This defined benefit SERP was closed to new entrants beginning January 1, 2010.

Post-Retirement Benefit Plans

AltaGas has several post-retirement benefit plans for unionized and non-unionized employees, including one in Canada and five in the United States. The post-retirement benefit plan in Canada is limited to the payment of life insurance and an annual allocation to a Healthcare Spending Account (HSA). This benefit plan is not funded.

Post-retirement benefit plans in the United States provide certain medical, prescription drug, dental, and life insurance benefits to eligible retired employees, their spouses and covered dependents. Benefits are based on a combination of the retiree's age and years of service at retirement. For eligible Washington Gas retirees and dependents not yet receiving Medicare benefits, Washington Gas provides medical, prescription drug, and dental benefits through Preferred Provider Organization (PPO) or Health Maintenance Organization (HMO) plans, through the Washington Gas Light Company Retiree Medical Plan. For Medicare-eligible retirees age 65 and older and their dependents, eligible retirees and dependents participate in a tax-free Health Reimbursement Account (HRA) Plan. The HRA plan provides an annual subsidy to help purchase supplemental medical, prescription drug and dental coverage in the marketplace. One of these benefit plans is partially funded, three are fully funded, and one is not funded.

Rabbi Trusts

Rabbi trusts of $18 million as at December 31, 2021 have been funded to satisfy the employee benefit obligations associated with WGL's various pension plans (December 31, 2020 - $28 million). These balances are included in prepaid expenses and other current assets and long-term investments and other assets in the Consolidated Balance Sheets.

The following table summarizes the details of the defined benefit plans, including the SERP and post-retirement plans in Canada and the United States:

Year Ended December 31, 2021	Canada		United States		Total	
	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits
Projected benefit obligation [(a)]						
Balance, beginning of year	$ 37	$ 2	$ 1,800	$ 452	$ 1,837	$ 454
Actuarial gain	(4)	—	(39)	(19)	(43)	(19)
Current service cost	4	—	23	10	27	10
Member contributions	—	—	—	2	—	2
Interest cost	1	—	49	12	50	12
Benefits paid	(4)	—	(74)	(25)	(78)	(25)
Expenses paid	—	—	(1)	—	(1)	—
Settlements	—	—	(7)	—	(7)	—
Plan amendments	—	—	—	(1)	—	(1)
Foreign exchange translation	—	—	(8)	(1)	(8)	(1)
Balance, end of year	$ 34	$ 2	$ 1,743	$ 430	$ 1,777	$ 432
Plan assets						
Fair value, beginning of year	$ 16	$ —	$ 1,667	$ 1,016	$ 1,683	$ 1,016
Actual return on plan assets	—	—	125	67	125	67
Employer contributions	4	—	11	—	15	—
Member contributions	—	—	—	2	—	2
Benefits paid	(4)	—	(74)	(23)	(78)	(23)
Expenses paid	—	—	(1)	—	(1)	—
Settlements	—	—	(7)	—	(7)	—
Other	—	—	—	—	—	—
Foreign exchange translation	—	—	(6)	(4)	(6)	(4)
Fair value, end of year	$ 16	$ —	$ 1,715	$ 1,058	$ 1,731	$ 1,058
Funded status	$ (18)	$ (2)	$ (28)	$ 628	$ (46)	$ 626

(a) For post-retirement benefit plans, the projected benefit obligation represents the accumulated benefit obligation.

Year Ended December 31, 2020	Canada		United States		Total	
	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits
Projected benefit obligation [a]						
Balance, beginning of year	$ 36	$ 2	$ 1,725	$ 428	$ 1,761	$ 430
Actuarial loss (gain)	1	—	137	32	138	32
Current service cost	3	—	27	9	30	9
Member contributions	—	—	—	2	—	2
Interest cost	1	—	60	15	61	15
Benefits paid	(4)	—	(82)	(24)	(86)	(24)
Expenses paid	—	—	(1)	—	(1)	—
Settlements	—	—	(25)	—	(25)	—
Foreign exchange translation	—	—	(41)	(10)	(41)	(10)
Balance, end of year	$ 37	$ 2	$ 1,800	$ 452	$ 1,837	$ 454
Plan assets						
Fair value, beginning of year	$ 15	$ —	$ 1,504	$ 906	$ 1,519	$ 906
Actual return on plan assets	1	—	275	157	276	157
Employer contributions	4	—	37	—	41	—
Member contributions	—	—	—	2	—	2
Benefits paid	(4)	—	(82)	(24)	(86)	(24)
Expenses paid	—	—	(1)	—	(1)	—
Settlements	—	—	(25)	—	(25)	—
Foreign exchange translation	—	—	(41)	(25)	(41)	(25)
Fair value, end of year	$ 16	$ —	$ 1,667	$ 1,016	$ 1,683	$ 1,016
Funded status	$ (21)	$ (2)	$ (133)	$ 564	$ (154)	$ 562

(a) For post-retirement benefit plans, the projected benefit obligation represents the accumulated benefit obligation.

For the year ended December 31, 2021, AltaGas' defined benefit and post-retirement benefit pension plans incurred actuarial gains primarily due to the increase in discount rates, which were the result of an increase in high-quality corporate bond yield curves in the Canadian and U.S. markets. For the year ended December 31, 2020, AltaGas' defined benefit plans incurred actuarial losses due to the decrease in discount rates, which were the result of a decline in high-quality corporate bond yield curves in the Canadian and U.S. markets. In 2020, AltaGas' post-retirement benefits plans also incurred actuarial losses primarily due to the previously mentioned decrease in discount rates, as well as updated census data and assumptions related to the HRA.

The following amounts were included in the Consolidated Balance Sheets:

	December 31, 2021			December 31, 2020		
	Defined Benefit	**Post-Retirement Benefits**	**Total**	Defined Benefit	Post-Retirement Benefits	Total
Prepaid post-retirement benefits	**$ 37**	**$ 637**	**$ 674**	$ —	$ 572	$ 572
Accounts payable and accrued liabilities [a]	**(8)**	**—**	**(8)**	(9)	—	(9)
Future employee obligations	**(75)**	**(11)**	**(86)**	(145)	(10)	(155)
	$ (46)	**$ 626**	**$ 580**	$ (154)	$ 562	$ 408

(a) Account balances on the Consolidated Balance Sheets also include certain non-pension related amounts.

The accumulated benefit obligation for all defined benefit plans were:

As at		December 31, 2021		December 31, 2020	
		Canada	United States	Canada	United States
Accumulated benefit obligation [(a)]	$	33	$ 1,659	$ 36	$ 1,704

(a) Accumulated benefit obligation differs from projected benefit obligation in that it does not include an assumption with respect to future compensation levels.

For those pension plans where the projected benefit obligation exceeded the fair value of plan assets as at December 31, 2021, the cumulative obligation and asset balances were:

As at		December 31, 2021		December 31, 2020	
		Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits
Projected benefit obligation	$	375	$ 14	$ 1,824	$ 14
Plan assets	$	289	$ 3	$ 1,670	$ 3

For those pension plans where the accumulated benefit obligation exceeded the fair value of plan assets as at December 31, 2021, the cumulative obligation and asset balances were:

As at		December 31, 2021		December 31, 2020	
		Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits
Accumulated benefit obligation	$	221	$ 14	$ 427	$ 14
Plan assets	$	158	$ 3	$ 329	$ 3

The following amounts were recorded in other comprehensive income (loss) and have not yet been recognized in net periodic benefit cost:

Year Ended December 31, 2021		**Canada**		**United States**		**Total**	
		Defined Benefit	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**
Past service cost	$	—	$ —	$ —	$ (2)	$ —	$ (2)
Net actuarial gain (loss)		(5)	(1)	4	(6)	(1)	(7)
Recognized in AOCI pre-tax	$	(5)	$ (1)	$ 4	$ (8)	$ (1)	$ (9)
Increase (decrease) by the amount included in deferred tax liabilities		1	—	(1)	2	—	2
Net amount in AOCI after-tax	$	(4)	$ (1)	$ 3	$ (6)	$ (1)	$ (7)

Year Ended December 31, 2020		Canada		United States		Total	
		Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits
Past service cost	$	—	$ —	$ —	$ (3)	$ —	$ (3)
Net actuarial gain (loss)		(9)	(1)	6	(8)	(3)	(9)
Recognized in AOCI pre-tax	$	(9)	$ (1)	$ 6	$ (11)	$ (3)	$ (12)
Increase (decrease) by the amount included in deferred tax liabilities		2	—	(2)	3	—	3
Net amount in AOCI after-tax	$	(7)	$ (1)	$ 4	$ (8)	$ (3)	$ (9)

The following amounts were recorded in a regulatory asset (liability) and have not yet been recognized in net periodic benefit cost:

Year Ended December 31, 2021	**Canada**		**United States**		**Total**	
	Defined Benefit	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**
Past service credit	$ —	$ —	$ —	$ (77)	$ —	$ (77)
Net actuarial gain	—	—	(26)	(289)	(26)	(289)
Recognized in regulatory liability	$ —	$ —	$ (26)	$ (366)	$ (26)	$ (366)

Year Ended December 31, 2020	Canada		United States		Total	
	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits
Past service credit	$ —	$ —	$ —	$ (94)	$ —	$ (94)
Net actuarial loss (gain)	—	—	68	(241)	68	(241)
Recognized in regulatory asset (liability)	$ —	$ —	$ 68	$ (335)	$ 68	$ (335)

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.

The net pension expense by plan was as follows:

	Year Ended December 31, 2021					
	Canada		**United States**		**Total**	
	Defined Benefit	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**
Current service cost [(a)]	$ 4	$ —	$ 23	$ 10	$ 27	$ 10
Interest cost [(b)]	1	—	49	12	50	12
Expected return on plan assets [(b)]	(1)	—	(76)	(34)	(77)	(34)
Amortization of past service credit [(b)]	—	—	—	(18)	—	(18)
Amortization of net actuarial loss (gain) [(b)]	1	—	6	(6)	7	(6)
Plan settlements [(b)]	—	—	2	—	2	—
Net benefit cost (income) recognized	$ 5	$ —	$ 4	$ (36)	$ 9	$ (36)

(a) Recorded under the line item "operating and administrative" expenses on the Consolidated Statements of Income.

(b) Recorded under the line item "other income" on the Consolidated Statements of Income.

	Year Ended December 31, 2020					
	Canada		United States		Total	
	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits
Current service cost [a]	$ 3	$ —	$ 27	$ 9	$ 30	$ 9
Interest cost [b]	1	—	60	15	61	15
Expected return on plan assets [b] [c]	(1)	—	(81)	(40)	(82)	(40)
Amortization of past service credit [b]	—	—	—	(19)	—	(19)
Amortization of net actuarial loss (gain) [b] [c]	1	—	10	(5)	11	(5)
Plan settlements [b]	—	—	7	—	7	—
Net benefit cost (income) recognized	$ 4	$ —	$ 23	$ (40)	$ 27	$ (40)

(a) Recorded under the line item "operating and administrative" expenses on the Consolidated Statements of Income.

(b) Recorded under the line item "other income" on the Consolidated Statements of Income.

(c) Includes the impact of the voluntary change in accounting principle implemented in 2020. Refer to Note 2 for additional information.

The objective for fund returns for the Canadian defined benefit pension plan is a liability-matching fixed income portfolio that is constructed to have similar characteristics as the liabilities of the pension plan. The liability-matching fixed income portfolio is determined as the combination of fixed income indices that exhibit the same sensitivity to real and nominal interest rate changes as the liabilities of the pension plan.

The objective for fund returns for the pension plans in the United States, over three to five-year periods, is the sum of two components - a passive component, which is the benchmark index market returns for the asset mix in effect, plus the added value expected from active management, if applicable to the fund. It is the Corporation's belief that the potential additional returns justify the additional risk associated with active management. The risk inherent in the investment strategy over a market cycle (a three-to five-year period) is two-fold. There is a risk that the market returns, as measured by the benchmark returns, will not be in line with expectations. The other risk is that the expected added value of active management over passive management will not be realized over the time period prescribed in each fund manager's mandate. There is also the risk of annual volatility in returns, which means that in any one year the actual return may be very different from the expected return.

Cash and money market investments may be held from time to time as short-term investment decisions at the discretion of the fund manager(s) within the constraints prescribed by their mandate(s).

The Corporation's target asset mix for the Canadian defined benefit plan is 100 percent fixed income assets. The target asset mix for SEMCO plans is 33 percent fixed income assets, for WGL plans is 50 percent to 70 percent fixed income assets. These objectives have taken into account the nature of the liabilities and the risk-reward tolerance of the Corporation.

The collective investment mixes for the plans are as follows as at December 31, 2021:

Canada	**Fair value**	Level 1	Level 2	Percentage of Plan Assets (%)
Cash and short-term equivalents	**$ 2**	$ 2	$ —	13
Fixed income	**14**	14	—	87
	$ 16	$ 16	$ —	100

United States		Fair value		Level 1		Level 2	Percentage of Plan Assets (%)
Cash and short-term equivalents	**$**	**8**	$	8	$	—	—
Canadian equities		**2**		2		—	—
Foreign equities [(a)]		**350**		350		—	13
Fixed income		**1,074**		148		926	39
Derivatives		**6**		—		6	—
Other [(b)]		**17**		—		17	1
Total investments in the fair value hierarchy	**$**	**1,457**	$	508	$	949	53
Investments measured at net asset value using the NAV practical expedient [(c)]							
Commingled funds [(d)]	**$**	**760**					27
Private equity/limited partnership [(e)]		**46**					2
Pooled separate accounts [(f)]		**38**					1
Collective trust fund [(g)]		**467**					17
Total fair value of plan investments	**$**	**2,768**					100
Net receivable [(h)]		**5**					—
	$	**2,773**					100

(a) Investments in foreign equities include U.S. and international securities.

(b) As at December 31, 2021, these investments consisted primarily of non-U.S. government bonds.

(c) In accordance with ASC Topic 820, these investments are measured at fair value using net asset value (NAV) per share as a practical expedient and, therefore, have not been classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliations of the fair value hierarchy to the statements of net assets available for plan benefits.

(d) As at December 31, 2021, investments in commingled funds consisted of approximately 51 percent common stock of large-cap U.S. companies, 21 percent U.S. Government fixed income securities, and 28 percent corporate bonds for WGL's post-retirement benefit plans.

(e) As at December 31, 2021, investments in a private equity/limited partnership consisted of common stock of international companies.

(f) As at December 31, 2021, investments in pooled separate accounts consisted of 100 percent income producing properties located in the United States.

(g) As at December 31, 2021, investments in collective trust funds consisted primarily of 91 percent common stock of U.S, companies, and 9 percent income producing properties located in the United States.

(h) As at December 31, 2021, this net receivable primarily represents pending trades for investments sold and interest receivable net of pending trades for investments purchased.

Total		Fair value		Level 1		Level 2	Percentage of Plan Assets (%)
Cash and short-term equivalents	**$**	**10**	$	10	$	—	—
Canadian equities		**2**		2		—	—
Foreign equities [(a)]		**350**		350		—	13
Fixed income		**1,088**		162		926	39
Derivatives		**6**		—		6	—
Other [(b)]		**17**		—		17	1
Total investments in the fair value hierarchy	**$**	**1,473**	$	524	$	949	53
Investments measured at net asset value using the NAV practical expedient [(c)]							
Commingled funds[(d)]	**$**	**760**					27
Private equity/limited partnership [(e)]		**46**					2
Pooled separate accounts [(f)]		**38**					1
Collective trust fund [(g)]		**467**					17
Total fair value of plan investments	**$**	**2,784**					100
Net receivable [(h)]		**5**					—
	$	**2,789**					100

(a) Investments in foreign equities include U.S. and international securities.

(b) As at December 31, 2021, these investments consisted primarily of non-U.S. government bonds.

(c) In accordance with ASC Topic 820, these investments are measured at fair value using net asset value (NAV) per share as a practical expedient and, therefore, have not been classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliations of the fair value hierarchy to the statements of net assets available for plan benefits.

(d) As at December 31, 2021, investments in commingled funds consisted of approximately 51 percent common stock of large-cap U.S. companies, 21 percent U.S. Government fixed income securities, and 28 percent corporate bonds for WGL's post-retirement benefit plans.

(e) As at December 31, 2021, investments in a private equity/limited partnership consisted of common stock of international companies.

(f) As at December 31, 2021, investments in pooled separate accounts consisted of 100 percent income producing properties located in the United States.

(g) As at December 31, 2021, investments in collective trust funds consisted primarily of 91 percent common stock of U.S, companies, and 9 percent income producing properties located in the United States.

(h) As at December 31, 2021, this net receivable primarily represents pending trades for investments sold and interest receivable net of pending trades for investments purchased.

Year Ended December 31	2021		2020	
Significant actuarial assumptions used in measuring net benefit plan costs	**Defined Benefit**	**Post-Retirement Benefits**	Defined Benefit	Post-Retirement Benefits
Discount rate (%)	**1.90 - 2.85**	**2.50 - 3.10**	2.30 - 3.50	3.10 - 3.60
Expected long-term rate of return on plan assets (%) [(a)]	**4.75 - 7.00**	**3.37 - 7.00**	5.25 - 7.05	4.03 - 7.05
Rate of compensation increase (%)	**1.00 - 4.00**	**2.50 - 3.00**	2.75 - 4.00	3.50

(a) Only applicable for funded plans

As at December 31	2021		2020	
Significant actuarial assumptions used in measuring benefit obligations	**Defined Benefit**	**Post-Retirement Benefits**	Defined Benefit	Post-Retirement Benefits
Discount rate (%)	**2.50 - 3.10**	**3.10**	1.90 - 2.80	2.50 - 2.90
Rate of compensation increase (%)	**2.50 - 4.00**	**3.00**	1.73 - 3.93	2.50 - 3.00

The expected rate of return on assets is based on the current level of expected returns on risk free investments, the historical level of risk premium associated with other asset classes in which the portfolio is invested, and the expectations for future returns of each asset class. The expected return for each asset class was then weighted based on the target asset allocation to develop the expected rate of return on assets assumption for the portfolio.

The discount rate is based on yields available on high-quality long-term corporate bonds, with maturities matching the estimated timing and amount of expected benefit payments.

The estimates for health care benefits take into consideration increased health care benefits due to aging and cost increases in the future. The assumed health care cost trend rate used to measure the expected cost of benefits for the next year was between 2.5 and 6.0 percent. The health care cost trend rates were assumed to decline to between 2.5 and 4.5 percent by 2028.

The following table shows the expected cash flows for defined benefit pension and other post-retirement plans:

	Defined Benefit	Post-Retirement Benefits
Expected employer contributions:		
2022	$ 12	$ —
Expected benefit payments:		
2022	$ 91	$ 22
2023	$ 88	$ 21
2024	$ 89	$ 21
2025	$ 90	$ 21
2026	$ 91	$ 21
2027 - 2031	$ 468	$ 110

29. Commitments, Guarantees, and Contingencies

Commitments

AltaGas has long-term natural gas purchase and transportation arrangements, LPG purchase agreements, crude oil and condensate purchase agreements, electricity purchase arrangements, service agreements, pipeline and storage service contracts, capital commitments, environmental commitments, merger commitments, and operating leases for office space, office equipment, vehicles, rail cars, land, storage, aquatic surface use, and other equipment, all of which are transacted at market prices and in the normal course of business.

Future payments of these commitments as at December 31, 2021 are estimated as follows:

	2022	2023	2024	2025	2026	2027 & beyond	Total
Gas purchase [(a)]	$ 1,128	$ 900	$ 799	$ 760	$ 719	$ 3,400	**$ 7,706**
Pipeline and storage services [(b)]	450	400	339	310	271	893	**2,663**
LPG purchase [(c)]	436	342	252	199	139	267	**1,635**
Electricity purchase [(d)]	425	243	121	39	4	—	**832**
Operating leases [(e)]	92	73	83	69	62	196	**575**
Service agreements [(f) (g) (h)]	49	42	31	27	26	259	**434**
Environmental [(i)]	13	2	1	1	1	—	**18**
Post-acquisition contingent payments [(j)]	16	—	—	—	—	—	**16**
Crude oil and condensate purchase [(k)]	13	1	—	—	—	—	**14**
Merger commitments [(l)]	2	2	2	1	1	1	**9**
Capital projects [(m)]	3	—	—	—	—	—	**3**
	$ 2,627	$ 2,005	$ 1,628	$ 1,406	$ 1,223	$ 5,016	**$ 13,905**

(a) AltaGas enters into contracts to purchase natural gas from various suppliers for its utilities. These contracts are used 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. Gas purchase commitments are valued based on fixed prices and forward prices, which may fluctuate significantly from period to period.

(b) Pipeline and storage commitments include minimum payments for natural gas transportation, storage and peaking contracts that have expiration dates through 2044.

(c) AltaGas enters into contracts to purchase LPGs for its operations at RIPET and Ferndale. These contracts are used to ensure that there is an adequate supply of LPGs to meet shipment commitments and to minimize exposure to market price fluctuations. LPG purchase commitments are valued based on forward prices, which may fluctuate significantly from period to period.

(d) AltaGas enters into contracts to purchase electricity from various suppliers for its non-utility business. Electricity purchase commitments are based on existing fixed price and fixed volume contracts, and include US$48 million of commitments related to renewable energy credits.

(e) Operating leases include lease arrangements for office space, office equipment, field equipment, rail cars, aquatic use, vehicles, power and gas facilities, transmission and distribution assets, and land. Operating leases also include US$150 million in future undiscounted cash flows associated with leasing arrangements for the use of Very Large Gas Carriers (VLGCs) that are anticipated to commence between 2023 and 2024.

(f) In 2014, AltaGas' Blythe facility entered into a Long-Term Service Agreement (LTSA) with a service pro to complete various upgrade and maintenance services on the Combustion Turbines (CT) at the Blythe facility over 124,000 equivalent operating hours per CT, or 25 years, whichever comes first. The LTSA has variable fees on a per equivalent operating hour basis. As at December 31, 2021, the total commitment was $147 million payable over the next 14 years, of which $48 million is expected to be paid over the next 5 years.

(g) In 2017, AltaGas entered into a 12-year service agreement commencing in 2019 for tug services to support the marine operations of RIPET.

(h) In 2015, AltaGas entered into a Project Agreement that contemplated the sublease of lands from Ridley Terminals Inc. (RTI), provision of certain terminal services, and access to RTI's terminal facilities to support RIPET's operations for an initial term of 20 years ending in 2039. In 2019, RILE LP and RTI executed a Terminal Services Agreement that formalized the concepts outlined in the Project Agreement.

(i) Environmental commitments include committed payments related to certain environmental response costs.

(j) Contingent payments of up to $16 million are expected to be paid related to the Petrogas Acquisition (Note 3).

(k) AltaGas enters into contracts to purchase crude oil and condensates for marketing, sale, and distribution. These contracts are used to ensure that there is an adequate supply of crude oil and condensates to meet the needs of customers and to minimize exposure to market price fluctuations. Crude oil and condensate commitments are valued based on forward prices, which may fluctuate significantly from period to period.

(l) Represents the estimated future payments of WGL merger commitments that have been accrued but not paid. As at December 31, 2021, the cumulative amount of merger commitments that have been expensed but not yet paid is approximately US$7 million. Additionally, there are a number of operational commitments, including the funding of leak mitigation and reducing leak backlogs, the funding of damage prevention efforts, developing projects to extend natural gas service, maintaining pre-merger quality of service standards including odor call response times, increasing supplier diversity, achieving synergy savings benefits, as well as reporting and tracking related to all the commitments, and developing 15 megawatts of either electric grid energy storage or Tier 1 renewable resources within five years after the merger closed.

(m) Commitments for capital projects. Estimated amounts are subject to variability depending on the actual construction costs.

Guarantees

AltaGas has guaranteed payments primarily for certain commitments on behalf of some of its subsidiaries. AltaGas has also guaranteed payments for certain of its external partners. With the sale of WGL Midstream in the second quarter of 2021, as at December 31, 2021, a US$25 million WGL performance guarantee to a former WGL Midstream wholesale counterparty remained in effect until the purchaser can transfer the credit support. In return, the purchaser provided a US$25 million third-party bank letter of credit in which WGL is the beneficiary. As at December 31, 2021, AltaGas has no other 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.

30. Related Party Transactions

In the normal course of business, AltaGas transacts with its subsidiaries, affiliates and joint ventures. Amounts due to or from related parties on the Consolidated Balance Sheets were measured at the exchange amount and were as follows:

As at		**December 31, 2021**		December 31, 2020
Due from related parties				
Accounts receivable [(a)]	**$**	**7**	$	5
Due to related parties				
Accounts payable [(b)]	**$**	**7**	$	3

(a) Receivables from joint ventures, affiliates and from a former affiliate of Petrogas.
(b) Payables to a joint venture, affiliates and a former affiliate of Petrogas.

The following transactions with related parties have been recorded on the Consolidated Statements of Income for the years ended December 31, 2021 and 2020:

Year Ended December 31		**2021**		2020
Revenue [(a)]	**$**	**—**	$	92
Cost of sales [(b)]	**$**	**6**	$	12
Operating and administrative expenses [(c)]	**$**	**—**	$	1
Other income [(d)]	**$**	**—**	$	3

(a) Prior to the disposition of AltaGas' equity interest in ACI (now named TriSummit Utilities Inc.) and the acquisition of Petrogas, in the ordinary course of business, AltaGas sold commodities to TriSummit Utilities Inc. and Petrogas.
(b) In the ordinary course of business, AltaGas obtained natural gas storage services from a joint venture as well as incurred costs related to the sale of natural gas liquids to affiliates.
(c) Subsequent to the close of the Petrogas Acquisition, certain operating and administrative expenses were paid on behalf of Petrogas by a former affiliate.
(d) Interest income from loans to Petrogas (secured loan facility) prior to the acquisition of Petrogas.

31. Supplemental Cash Flow Information

The following table details the changes in operating assets and liabilities from operating activities:

	Year Ended December 31	
	2021	2020
Source (use) of cash:		
Accounts receivable	**$ (206)**	$ 21
Inventory	**(232)**	32
Risk management assets - current	**4**	(30)
Other current assets	**4**	31
Regulatory assets - current	**(3)**	(33)
Accounts payable and accrued liabilities	**92**	(41)
Customer deposits	**27**	(2)
Regulatory liabilities - current	**(12)**	(55)
Risk management liabilities - current	**(1)**	(1)
Other current liabilities	**21**	4
Other operating assets and liabilities	**(104)**	(129)
Changes in operating assets and liabilities	**$ (410)**	$ (203)

The following table details the changes in non-cash investing and financing activities:

	Year Ended December 31	
	2021	2020
Decrease (increase) of balance:		
Common shares issued under DRIP	**$ —**	$ (6)
Exercise of stock options	**$ 2**	$ —
Common share dividends payable	**$ 22**	$ —
Net right-of-use assets obtained in exchange for new operating lease liabilities	**$ (38)**	$ (227)
Net right-of-use assets obtained in exchange for new finance lease liabilities	**$ (10)**	$ (6)
Capital expenditures included in accounts payable and accrued liabilities	**$ 33**	$ (33)

The following cash payments have been included in the determination of earnings:

	Year Ended December 31	
	2021	2020
Interest paid (net of capitalized interest)	**$ 279**	$ 276
Income taxes paid	**$ 69**	$ 23

The following table is a reconciliation of cash and restricted cash balances:

As at December 31		2021		2020
Cash and cash equivalents	$	**63**	$	32
Restricted cash holdings from customers - current		**3**		3
Restricted cash holdings from customers - non-current		**—**		2
Restricted cash included in prepaid expenses and other current assets [(a)]		**8**		9
Restricted cash included in long-term investments and other assets *(note 12)* [(a)]		**10**		19
Restricted cash included in accounts receivable *(note 29)*		**—**		9
Cash, cash equivalents, and restricted cash per Consolidated Statements of Cash Flows	$	**84**	$	74

(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 (see Note 28).

32. 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 reporting segments:

Utilities	▪ rate-regulated natural gas distribution assets in Michigan, Alaska, the District of Columbia, Maryland, and Virginia; ▪ rate-regulated natural gas storage in the United States; and ▪ sale of energy to residential, commercial and industrial customers in Washington D.C., Maryland, Virginia, Delaware, Pennsylvania and Ohio.
Midstream	▪ NGL processing and extraction plants; ▪ natural gas storage facilities; ▪ liquefied petroleum gas (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 fuels, crude oil and condensate diluents; and ▪ interest in a regulated 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 remaining power assets.

The following table provides a reconciliation of segment revenue to the disaggregated revenue table disclosed in Note 24:

	Year Ended December 31, 2021							
		Utilities		**Midstream**		**Corporate/ Other**		**Total**
External revenue *(note 24)*	$	**3,936**	$	**6,533**	$	**104**	$	**10,573**
Intersegment revenue		**—**		**2**		**—**		**2**
Segment revenue	$	**3,936**	$	**6,535**	$	**104**	$	**10,575**

	Year Ended December 31, 2020			
	Utilities	Midstream	Corporate/ Other	Total
External revenue *(note 24)*	$ 3,817	$ 1,635	$ 135	$ 5,587
Intersegment revenue	—	1	—	1
Segment revenue	$ 3,817	$ 1,636	$ 135	$ 5,588

Geographic Information

Year Ended December 31	**2021**	2020
Revenue [a]		
Canada	**$ 6,420**	$ 1,512
United States	**4,304**	4,053
Total	**$ 10,724**	$ 5,565

(a) Operating revenue from external customers, excluding unrealized gains or losses on risk management contracts.

As at December 31	**2021**	2020
Property, plant and equipment		
Canada	**$ 3,109**	$ 3,149
United States	**8,214**	7,739
Total	**$ 11,323**	$ 10,888
Operating right-of-use assets		
Canada	**$ 239**	$ 293
United States	**72**	79
Total	**$ 311**	$ 372

The following tables show the composition by segment:

	Year Ended December 31, 2021				
	Utilities	Midstream	Corporate/ Other	Intersegment Elimination [a]	Total
Segment revenue *(note 24)*	**$ 3,936**	**$ 6,535**	**$ 104**	**$ (2)**	**$ 10,573**
Cost of sales	**(2,273)**	**(5,412)**	**(25)**	**2**	**(7,708)**
Operating and administrative	**(906)**	**(475)**	**(95)**	**—**	**(1,476)**
Accretion expenses	**(1)**	**(6)**	**1**	**—**	**(6)**
Depreciation and amortization	**(285)**	**(104)**	**(33)**	**—**	**(422)**
Provisions on assets *(note 6)*	**—**	**(59)**	**(5)**	**—**	**(64)**
Income (loss) from equity investments	**2**	**(263)**	**—**	**—**	**(261)**
Other income	**65**	**16**	**—**	**—**	**81**
Foreign exchange gains (losses)	**—**	**10**	**(6)**	**—**	**4**
Interest expense	**—**	**—**	**(275)**	**—**	**(275)**
Income (loss) before income taxes	**$ 538**	**$ 242**	**$ (334)**	**$ —**	**$ 446**
Net additions (reductions) to:					
Property, plant and equipment [b]	**$ 705**	**$ (284)**	**$ 8**	**$ —**	**$ 429**
Intangible assets	**$ 2**	**$ 2**	**$ 2**	**$ —**	**$ 6**

(a) Intersegment transactions are recorded at market value.

(b) 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.

	Year Ended December 31, 2020				
	Utilities	Midstream	Corporate/ Other	Intersegment Elimination [a]	Total
Segment revenue *(note 24)*	$ 3,817	$ 1,636	$ 135	$ (1)	$ 5,587
Cost of sales	(2,156)	(994)	(29)	1	(3,178)
Operating and administrative	(942)	(254)	(71)	—	(1,267)
Accretion expenses	—	(4)	(1)	—	(5)
Depreciation and amortization	(295)	(86)	(33)	—	(414)
Provision on assets *(note 6)*	(1)	(105)	(3)	—	(109)
Income from equity investments	5	44	—	—	49
Other income	259	24	23	—	306
Foreign exchange gains (losses)	—	(26)	30	—	4
Interest expense	—	—	(274)	—	(274)
Income (loss) before income taxes	$ 687	$ 235	$ (223)	$ —	$ 699
Net additions (reductions) to:					
Property, plant and equipment [b] [c]	$ 703	$ 136	$ (51)	$ —	$ 788
Intangible assets	$ 3	$ 3	$ 4	$ —	$ 10

(a) Intersegment transactions are recorded at market value.

(b) 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.

(c) In 2021, Management determined that it would include adjustments for the cost of removal of utility assets in net additions to property, plant and equipment. Comparative periods have been restated to reflect this change.

The following table shows goodwill and total assets by segment:

	Utilities	Midstream	Corporate/ Other	Total
As at December 31, 2021				
Goodwill	**$ 3,691**	**$ 1,462**	**$ —**	**$ 5,153**
Segmented assets	**$ 14,603**	**$ 6,415**	**$ 575**	**$ 21,593**
As at December 31, 2020				
Goodwill	$ 3,706	$ 1,333	$ —	$ 5,039
Segmented assets	$ 13,675	$ 7,320	$ 537	$ 21,532

33. Subsequent Events

On January 11, 2022, AltaGas closed its offering of $300 million of 5.25 percent Fixed-to-Fixed Rate Subordinated Notes, Series 1, due January 11, 2082. As a result of the offering, based on current rates, AltaGas expects cash savings of approximately $66 million over the initial ten-year term of the offering due to lower taxes and financing charges. The subordinated notes were offered under AltaGas' short form base shelf prospectus dated February 22, 2021, as supplemented by a prospectus supplement dated January 5, 2022. On February 16, 2022, AltaGas provided notice to shareholders of its intention to use the proceeds of this offering to redeem all of its issued and outstanding Series K Preferred Shares on March 31, 2022 for a redemption price equal to $25.00 per Series K Share.

In January 2022, AltaGas agreed to sell one of its customers an interest in certain Midstream processing facilities for total consideration of approximately $234 million. The transaction is expected to close in the second quarter of 2022.

On February 9, 2022, pursuant to the terms of a Membership Interest Purchase Agreement entered into on January 14, 2022 with an undisclosed buyer, AltaGas closed the sale of a 60 MW stand-alone energy storage development project in Goleta, California for total proceeds of approximately US$15 million, subject to certain contingencies.

On February 11, 2022, AltaGas entered into a stock purchase agreement to sell a 70MW combined cycle power plant in Brush, Colorado. The transaction is expected to close in the second quarter of 2022.

Subsequent events have been reviewed through March 3, 2022, the date on which these audited Consolidated Financial Statements were issued.

SUPPLEMENTAL QUARTERLY OPERATING INFORMATION

	Q4-21	Q3-21	Q2-21	Q1-21	Q4-20
OPERATING HIGHLIGHTS					
UTILITIES					
Natural gas deliveries - end use (Bcf) (1)	**44.0**	12.2	22.4	72.6	50.0
Natural gas deliveries - transportation (Bcf) (1)	**31.2**	21.4	25.3	43.1	35.6
Service sites (thousands) (2)	**1,689**	1,676	1,673	1,675	1,672
Degree day variance from normal - SEMCO Gas (%) (3)	**(15.0)**	(41.8)	(5.6)	(6.2)	(4.4)
Degree day variance from normal - ENSTAR (%) (3)	**11.9**	16.9	9.0	9.7	0.2
Degree day variance from normal - Washington Gas (%) (3) (4)	**(12.7)**	—	20.8	(7.1)	(10.6)
WGL retail energy marketing - gas sales volumes (Mmcf)	**16,299**	7,682	9,887	24,696	18,053
WGL retail energy marketing - electricity sales volumes (GWh)	**3,167**	3,738	3,201	3,249	3,257
MIDSTREAM					
RIPET export volumes (Bbls/d) (5)	**48,974**	58,056	44,973	50,714	37,782
Ferndale export volumes (Bbls/d) (5) (6)	**27,635**	47,014	45,133	34,750	33,979
Total inlet gas processed (Mmcf/d) (5)	**1,534**	1,471	1,460	1,526	1,409
Extraction ethane volumes (Bbls/d) (5)	**27,000**	22,938	28,867	33,138	30,766
Extraction NGL volumes (Bbls/d) (5) (7)	**35,734**	34,671	37,070	38,026	34,199
Fractionated volumes (Bbls/d) (5)	**37,000**	29,130	27,900	28,591	27,026
Frac spread - realized ($/Bbl) (5) (8)	**9.18**	12.63	11.59	14.69	13.95
Frac spread - average spot price ($/Bbl) (5) (9)	**35.82**	36.32	20.54	24.35	9.33
Propane Far East Index (FEI) to Mont Belvieu spread (US$/Bbl) (5) (10)	**12.65**	9.00	8.98	10.14	15.01
Butane FEI to Mont Belvieu spread (US$/Bbl) (5) (11)	**10.29**	8.79	10.03	12.74	12.84
Natural gas optimization inventory (Bcf)	**2.0**	2.6	1.3	23.9	39.3

(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, during the prior 10 years for ENSTAR, 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 that 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) Average for the period.

(6) Represents propane and butane volumes exported at Ferndale for the period after close of the Petrogas Acquisition on December 15, 2020.

(7) NGL volumes refer to propane, butane, and condensate.

(8) 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.

(9) 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.

(10) Average propane price spread between FEI and Mont Belvieu TET commercial index.

(11) Average butane price spread between FEI and Mont Belvieu TET commercial index for the period beginning December 15, 2020.

OTHER INFORMATION

DEFINITIONS

Bbls/d	barrels per day
Bcf	billion cubic feet
Dth	dekatherm
GJ	gigajoule
GWh	gigawatt-hour
Mcf	thousand 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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