MANAGEMENT'S DISCUSSION AND ANALYSIS

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

This Management's Discussion and Analysis ("MD&A") dated July 26, 2022, is provided to enable readers to assess the results of operations, liquidity and capital resources of TriSummit Utilities Inc. ("TSU" or the "Company") as at and for the three and six months ended June 30, 2022. This MD&A should be read in conjunction with the accompanying condensed interim consolidated financial statements as at and for the three and six months ended June 30, 2022 (the "Interim Financial Statements"), the Company's audited consolidated financial statements as at and for the year ended December 31, 2021 (the "2021 Annual Financial Statements") and the Company's management's discussion and analysis for the year ended December 31, 2021 (the "2021 Annual MD&A").

The Company's presentation currency is in Canadian dollars. In this MD&A, references to "$" are to Canadian dollars unless otherwise indicated. The Interim Financial Statements and comparative information have been prepared in accordance with United States ("U.S.") generally accepted accounting principles ("U.S. GAAP") as codified by the Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC"). Throughout this MD&A, reference to GAAP refers to U.S. GAAP. Any reference to per Common Share measures are presented on a basic basis, unless otherwise indicated.

This MD&A refers to certain terms commonly used in the rate-regulated utility industry, such as "rate-regulated", "rate base" and "return on equity". The terms "rate base" and "return on equity" are key performance indicators but are not considered to be non-GAAP measures. Rate base is an amount that a utility is required to calculate for regulatory purposes, and generally refers to net book value of the utility's assets for regulatory purposes. Return on equity or "ROE" is a percentage that is set or approved by a utility's regulator and represents the rate of return that a regulator allows the utility to earn on the equity component of the utility's rate base. The Company refers to the rate base of its utility businesses because it believes that such term assists in understanding the Company's business and is commonly used by investors to help evaluate the performance of rate-regulated utilities. For a discussion of these terms and other terms commonly used in the rate-regulated utility industry, please see the "*Business of the Company - Utilities Business*" section in the annual information form of TSU dated March 2, 2022 (the "Annual Information Form").

Abbreviations, acronyms, and capitalized terms used in this MD&A that are not otherwise defined herein are used consistently with the definitions in the 2021 Annual MD&A or the Annual Information Form.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This MD&A contains certain forward-looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "objective", "ongoing", "may", "will", "should", "believe", "plan", "would", "could", "focus", "forecast", "opportunity" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this MD&A contains forward-looking information and statements pertaining to the following: expected success of financing plans and strategies, including maintenance of TSU's credit rating; the expected safety and reliability of TSU's operations; expectations regarding the PNG Reactivation Project (as defined herein) and the Salvus to Galloway Project (as defined herein); the GCOC (as defined herein) and LCE (as defined herein) proceedings announced by the BCUC (as defined herein); the CGOC (as defined herein), cost of service, and PBR (as defined herein) proceedings announced by the AUC (as defined herein); expectations regarding planned expenditures and related investments and capital program from 2022 to 2026 and the expected capital spend in 2022, including the sources of financing for TSU's capital expenditures; expected fluctuations in the Company's working capital and the expected funding of the Company's capital program; the Company's objective for managing capital and its effects on rate base and return to investors; the payment of dividends to the Company's shareholder; the expected closing date of the Transaction (as defined herein); the expected benefits of the Transaction; financing plans for the Transaction; plans for the operation of the Alaska Utilities Business (as defined herein) and investments to be made in the local community following close of the Transaction; the impact of the Transaction in respect of TSU's business (including, without limitation, in respect of rate base and other characteristics) and on TSU's strategic plans; the Natural Gas Rebate Program announced by the Government of Alberta; and expected impact of adopting ASUs (as defined herein) in the future on the Company's consolidated financial statements.

The forward-looking information and statements contained in this MD&A reflect several material factors, expectations and assumptions of the Company including, without limitation: satisfaction of all conditions to the Transaction; timely receipt of all necessary approvals; the success of the transition in ownership of the Alaska Utilities Business; expected commodity supply, demand and pricing; that the Company will continue to conduct its operations in a manner consistent with past operations; the general continuance of current or, where applicable, assumed industry conditions; regulatory approvals and policies; funding operating and capital costs; project completion dates; capacity expectations; that there will be no material defaults by the counterparties to agreements with the Company and such agreements will not be terminated prior to their scheduled expiry; and the Company will continue to have access to wind and water resources in amounts consistent with the amounts expected by the Company. The Company believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable, but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information and statements included in this MD&A are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information and statements, including, without limitation: changes in the demand for or supply of the Company's services; unanticipated operating results; changes in regulatory matters; limited, unfavourable or a lack of access to capital markets; increased costs; the impact of competitors; attracting and retaining skilled personnel and certain other risks (including, without limitation, those risks identified elsewhere in this MD&A); and the other factors discussed under the heading *"Risk Factors"* in the Annual Information Form and set out in the Company's other continuous disclosure documents.

The Company believes the forward-looking statements in this MD&A are reasonable. However, such statements are not a guarantee that any of the actions, events or results of the forward-looking statements will occur, or if any of them do occur, their timing or what impact they will have on the Company's results of operations or financial condition. Because of these uncertainties, investors should not put undue reliance on any forward-looking statements.

The forward-looking statements included in this MD&A are expressly qualified by this cautionary statement and are made as of the date of this MD&A. The Company does not undertake any obligation to publicly update or revise any forward-looking statements except as required by Canadian securities laws.

Additional information relating to the Company, including the Annual Information Form, is available on SEDAR at *www.sedar.com.*

THE COMPANY

TSU is incorporated under the *Canada Business Corporations Act* and its registered office and principal place of business is in Calgary, Alberta. TSU is a wholly owned subsidiary of TriSummit Cycle Inc., a company in which the Public Sector Pension Investment Board indirectly holds a majority economic interest and Alberta Investment Management Corporation indirectly holds a minority economic interest.

The Company owns and operates rate-regulated distribution and transmission utility businesses through its wholly-owned operating subsidiaries Apex Utilities Inc. ("AUI") in Alberta, Pacific Northern Gas Ltd. ("PNG") and Pacific Northern Gas (N.E.) Ltd. ("PNG(N.E.)") in British Columbia and Heritage Gas Limited ("HGL") in Nova Scotia. The Company also owns the Bear Mountain Wind Park, an approximately 10 percent indirect interest in the Northwest Hydro Facilities, and a 33.33 percent equity interest in the utility that delivers natural gas to end-users in Inuvik, Northwest Territories.

SECOND QUARTER FINANCIAL HIGHLIGHTS

(Normalized EBITDA, normalized funds from operations (including per share amounts), normalized net income (loss) (including per share amounts), net debt, and net debt to total capitalization ratio are non-GAAP financial measures. Please see the *"Non-GAAP Financial Measures"* section of this MD&A.)

- Net loss after taxes was $1.4 million ($0.05 per Common Share) compared to net income after taxes of $4.0 million ($0.13 per Common Share) in the second quarter of 2021.
- Normalized net loss was $1.2 million ($0.04 per Common Share), compared to normalized net income of $3.5 million ($0.12 per Common Share) in the second quarter of 2021.
- Operating income was $6.2 million, compared to $11.3 million in the second quarter of 2021.
- Normalized EBITDA was $18.8 million, compared to $21.9 million in the second quarter of 2021.
- Cash from operations was $14.4 million, compared to $26.2 million in the second quarter of 2021.
- Normalized funds from operations were $9.9 million ($0.33 per Common Share), compared to normalized funds from operations $10.9 million ($0.36 per Common Share) in the second quarter of 2021.
- Net debt was $773.0 million as at June 30, 2022, compared to $768.5 million as at December 31, 2021.
- Net debt to total capitalization ratio was 54.8 percent as at June 30, 2022, compared to 55.0 percent as at December 31, 2021.
- Rate base as at June 30, 2022 was $1,097 million inclusive of construction work in progress, compared to $990 million as at June 30, 2021.
- On April 1, 2022, the British Columbia Utilities Commission ("BCUC") accepted PNG's biomethane purchase agreements ("BPAs") with ATCO Future Fuel RNG Limited Partnership ("ATCO") and Tidal Energy Marking Inc. ("Tidal") as meeting the requirements for a prescribed undertaking as defined by B.C.'s *Greenhouse Gas Reduction (Clean Energy) Regulation*.
- Effective May 25, 2022, the Company entered into a definitive agreement for a subsidiary of the Company to acquire 100 percent of ENSTAR Natural Gas Company ("ENSTAR") and the Alaska Pipeline Company, the Norstar Pipeline Company, Inc., and a 65 percent indirect interest in Cook Inlet Natural Gas Storage Alaska, LLC ("CINGSA") from a subsidiary of AltaGas Ltd. ("AltaGas") in an all cash transaction valued at approximately US$800 million, subject to customary closing adjustments.

OVERVIEW OF THE BUSINESS

TSU has three reporting segments:

- Utilities, which owns and operates rate-regulated distribution and transmission assets in Alberta, British Columbia and Nova Scotia. TSU also owns a 33.33 percent equity interest in the utility that delivers natural gas to end-users in Inuvik, Northwest Territories. In aggregate, the utilities had approximately $1,097 million of rate base as at June 30, 2022 inclusive of construction work in progress and serve approximately 133,000 customers across Canada.
- Renewable Energy, which includes the 102 MW Bear Mountain Wind Park and an approximately 10 percent indirect interest in the 303 MW Northwest Hydro Facilities.
- Corporate, which primarily includes the cost of providing shared services, financing and access to capital, general corporate support as well as the equity investment in the NGIF Cleantech Ventures Limited Partnership.

PENDING ACQUISITION OF THE ALASKA UTILITIES BUSINESS

Effective May 25, 2022, the Company entered into a definitive agreement for a subsidiary of the Company to acquire 100 percent of ENSTAR, the Alaska Pipeline Company, the Norstar Pipeline Company, Inc., and a 65 percent indirect interest in CINGSA (collectively, the "Alaska Utilities Business") from a subsidiary of AltaGas, in an all cash transaction (the "Transaction") valued at approximately US$800 million, subject to customary closing adjustments. The Transaction is not subject to any financing contingency and is expected to be funded by approximately US$470 million of common equity through TSU's indirect shareholders and approximately US$300 million of unsecured long-term debt through U.S. private placements, which is expected to be issued by TSU's newly formed wholly-owned U.S. subsidiaries. In addition, as at March 31, 2022, CINGSA had approximately US$47 million (approximately US$31 million proportionate share) of outstanding senior notes, which TSU expects to remain in place.

ENSTAR is the largest gas utility in the State of Alaska, servicing approximately 60 percent of the State's population, with approximately 150,000 customers and 3,626 miles of transmission and distribution pipeline. CINGSA, located in Kenai, Alaska, is the only commercial, fully contracted, state regulated gas storage facility in Alaska.

ENSTAR and the 65 percent interest in CINGSA had 2021 combined average rate base of approximately US$350 million. In 2021, ENSTAR's approved regulated ROE was 11.875 percent with an approved deemed capital structure of 51.8 percent equity, and CINGSA's approved regulated ROE was 10.25 percent with an approved deemed capital structure of 53 percent equity. Combined, ENSTAR and 100 percent of CINGSA's 2020-2021 two-year historical normalized EBITDA was approximately US$60 - $65 million per annum and normalized funds from operations was approximately US$45 - $50 million per annum. Normalized EBITDA and normalized funds from operations are non-GAAP financial measures, please see cautionary statement under the *"Non-GAAP Financial Measures"* section of this MD&A.

The Transaction is expected to significantly increase the Company's scale and capacity, growing TSU's consolidated rate base by approximately 40 percent to over $1.5 billion, and more than doubling its customer base. TSU believes ENSTAR has significant growth potential and intends to work closely with ENSTAR management to invest and support economic growth in the region. The Transaction will also provide greater geographical and business diversification. After the close of the Transaction, TSU will operate in multiple distinct regulatory jurisdictions in Canada and the United States.

Closing of the Transaction is subject to the satisfaction of certain customary closing conditions and certain regulatory and government approvals and clearances, including, among others, those of the Regulatory Commission of Alaska and compliance with applicable requirements under the *Hart-Scott Rodino Antitrust Improvements Act of 1976* ("HSR"). In June 2022, the applications for approval were filed with the relevant regulatory and governmental authorities. On July 11, 2022, the required waiting period under the HSR expired. The Transaction is expected to close no later than the first quarter of 2023.

BUSINESS AND REGULATORY UPDATES

PNG Reactivation Project

On November 30, 2021, the BCUC granted approval of the certificate of public convenience and necessity ("CPCN") application filed by PNG on March 5, 2021, for costs related to system reactivation and recommissioning work necessary to return the existing Western System back to the contracted utilization capacity (the "PNG Reactivation Project"). The submitted capital cost in the CPCN application is approximately $89 million and is expected to be incurred over a four-year period between 2021 and 2024. With the approval from the BCUC, construction began in the fourth quarter of 2021. As at June 30, 2022, $8.4 million of capital expenditures have been incurred to date on the PNG Reactivation Project.

On September 10, 2021, Port Edward LNG Ltd. ("Port Edward LNG"), a party to certain transportation and service agreements with PNG received approval from the British Columbia Oil and Gas Commission ("BCOGC") for its LNG project in Port Edward, British Columbia. Port Edward LNG subsequently received approval from the BCOGC on March 17, 2022, for an amendment to incorporate the second phase of their LNG Project. Under the terms of the transportation and service agreements with Port Edward LNG, demand charge payments are scheduled to begin in December 2022.

PNG Salvus to Galloway Project

On July 8, 2021, the BCUC granted approval of the CPCN application filed by PNG on October 2, 2020, for a project to repair and refurbish part of its Western System, specifically the 8" transmission line from Terrace, British Columbia, to Prince Rupert, British Columbia (the "Salvus to Galloway Project"). The project is required to address aging infrastructure and ensure long-term reliable supply. Project work will be conducted within the existing PNG corridor and nearby permitted temporary workspace. The submitted capital cost in the CPCN for the Salvus to Galloway Project is approximately $85 million, the majority of which is expected to be incurred over a three-year period, between 2021 and 2023. Following the approval from the BCUC, construction began in the summer of 2021 and will continue in phases with completion expected in the fall of 2023. As at June 30, 2022, $33.3 million of capital expenditures have been incurred to date on the Salvus to Galloway Project.

AUI GCOC Proceeding

On January 3, 2022, the AUC initiated a GCOC proceeding to establish the 2023 GCOC parameters for ROE and equity ratios

(Stage 1), and address 2024 and future years (Stage 2). On March 31, 2022, the AUC issued a decision for Stage 1 approving the extension of the current ROE of 8.5 percent and equity thickness of 39 percent for AUI for 2023. On June 29, 2022, the AUC initiated Stage 2 of the proceeding to establish the approach for setting ROE for 2024 and beyond and to consider whether any changes are required to the cost-of-capital parameters.

PNG GCOC Proceeding

In January 2021, the BCUC announced the initiation of a GCOC proceeding to address the appropriate common equity component and return on equity for the utilities it regulates. The BCUC is currently reviewing FortisBC's common equity component and return on equity. Other utilities including PNG are expected to be reviewed in 2023 after the BCUC has determined which FortisBC utility (gas or electric) should be used as the benchmark.

AUI 2023 Cost of Service Application

On June 18, 2021, the AUC issued a decision regarding the process to establish the 2023 rates for Alberta electric and gas distribution utilities. AUI's 2023 cost of service application was filed on December 15, 2021, with the record closing on June 3, 2022 upon the completion of oral argument and reply. It is expected a decision will be released in the third quarter of 2022.

AUI Third Performance Based Regulation ("PBR") Term

On May 26, 2022, the AUC issued Bulletin 2022-06 to initiate a proceeding for a third PBR term to be effective 2024. The scope of the proceeding will consider parameters from the second PBR term to be retained, modified, removed, or added.

AUI Hydrogen Inquiry

On November 5, 2021, the Government of Alberta released the Hydrogen Roadmap identifying the province as being well positioned to participate in the global hydrogen economy, with the province enabling hydrogen blending into natural gas distribution systems as one method to reduce greenhouse gas emissions. Upon the direction of the Minister of Energy, the AUC opened an inquiry on matters related to hydrogen blending in natural gas distribution systems. Written comments from inquiry participants, including AUI, were submitted in April 2022, and the AUC's report to the Minister of Energy was submitted on June 30, 2022.

AUI Natural Gas Rebate Program

On July 6, 2022, the Government of Alberta released preliminary details of a Natural Gas Rebate Program, which will be funded by the Province of Alberta, to help consumers manage higher winter heating costs. The rebate threshold is an absolute rate cap that will be triggered when the monthly gas cost recovery rate for any of Alberta's three regulated utility providers is above $6.50 per GJ and the rebate program is scheduled to run from October 1, 2022 to March 31, 2023.

PNG Application for Approval of a Low Carbon Energy Cost Recovery Mechanism and Biomethane Purchase Agreements

On April 1, 2022, the BCUC accepted PNG's BPAs with ATCO and Tidal as meeting the requirements for a prescribed undertaking as defined by B.C.'s *Greenhouse Gas Reduction (Clean Energy) Regulation*. This approval exempts the BPAs from regulatory review as to whether they are in the public interest. The BPAs provide biomethane supply for PNG's Low Carbon Energy ("LCE") program in support of the greenhouse gas reduction goals of PNG, its customers, and the Province of British Columbia. The regulatory process established by the BCUC to review the LCE cost recovery mechanism portion of PNG's application is complete and a decision by the BCUC is expected in the latter part of the third quarter of 2022.

CAPITAL PROGRAM GUIDANCE

Over the 2022 to 2026 time period, TSU expects capital spending of up to $700 million at its existing Utilities. The expected capital program includes the PNG Reactivation Project and the Salvus to Galloway Project, as well as investments in system betterment projects to maintain the safety and reliability of TSU's utility infrastructure, new business opportunities, technology improvements, and energy transition investments. In 2022, TSU expects capital spending to be in the range of $155 to $175 million.

SEASONALITY

Results for the Utilities segment have a high degree of seasonality associated with them as the second and third quarters usually produce lower net income as a result of warmer weather, lower customer demand, and certain expenses such as depreciation, operating and administrative expenses, and interest expense, which generally increase as a result of rate base growth and are more evenly distributed throughout the year. These increased costs are normally more than offset in the first and fourth quarters which produce higher net income as a result of colder weather and higher customer demand.

SELECTED FINANCIAL INFORMATION

The following tables summarize key financial results:

	Three Months Ended June 30		Six Months Ended June 30	
($ millions)	**2022**	2021	**2022**	2021
Normalized EBITDA(1)	**18.8**	21.9	**63.1**	62.8
Operating income	**6.2**	11.3	**38.6**	42.6
Net income (loss) after taxes	**(1.4)**	4.0	**27.3**	27.8
Normalized net income (loss)(1)	**(1.2)**	3.5	**28.2**	26.5
Total assets	**1,745.9**	1,624.8	**1,745.9**	1,624.8
Total long-term liabilities	**975.6**	942.5	**975.6**	942.5
Net additions to property, plant and equipment	**25.6**	15.9	**38.8**	25.1
Dividends declared	**8.8**	8.3	**17.6**	16.5
Cash from operations	**14.4**	26.2	**59.0**	63.7
Normalized funds from operations(1)	**9.9**	10.9	**50.1**	45.9

	Three Months Ended June 30		Six Months Ended June 30	
($ per Common Share, except Common Shares outstanding)	**2022**	2021	**2022**	2021
Net income (loss) after taxes - basic and diluted	**(0.05)**	0.13	**0.91**	0.93
Normalized net income (loss) - basic(1)	**(0.04)**	0.12	**0.94**	0.88
Dividends declared	**0.2925**	0.2750	**0.5850**	0.5500
Cash from operations	**0.48**	0.87	**1.97**	2.12
Normalized funds from operations(1)	**0.33**	0.36	**1.67**	1.53
Weighted average number of Common Shares outstanding - basic (millions)	**30.0**	30.0	**30.0**	30.0

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

The following table summarizes TSU's consolidated results:

	Three Months Ended June 30		Six Months Ended June 30	
($ millions)	**2022**	2021	**2022**	2021
Revenue	**84.8**	67.9	**248.1**	191.7
Cost of sales	**(36.7)**	(22.5)	**(126.5)**	(78.2)
Operating and administrative expense	**(33.3)**	(27.0)	**(63.0)**	(53.8)
Accretion expense	**(0.1)**	—	**(0.1)**	(0.1)
Depreciation and amortization expense	**(11.5)**	(10.1)	**(21.8)**	(19.3)
Income from equity investments	**1.5**	2.5	**0.4**	1.0
Unrealized gain on risk management contracts	**0.9**	0.5	**0.2**	1.3
Other income	**0.6**	0.1	**1.3**	0.2
Foreign exchange loss	**—**	(0.1)	**—**	(0.2)
Operating income	**6.2**	11.3	**38.6**	42.6
Interest expense	**(7.5)**	(7.0)	**(14.9)**	(13.9)
Income tax recovery (expense)	**(0.1)**	(0.3)	**3.6**	(0.9)
Net income (loss) after taxes	**(1.4)**	4.0	**27.3**	27.8

Three Months Ended June 30

Normalized EBITDA for the three months ended June 30, 2022 was $18.8 million, a decrease of $3.1 million relative to the same period in 2021 primarily due to lower revenues at Bear Mountain Wind Park, lower normalized EBITDA from the investment in the Northwest Hydro Facilities, and higher operating and administrative expense, partially offset by higher approved rates and rate base growth at the Utilities and colder weather in Alberta compared to the same period in 2021.

Operating income for the three months ended June 30, 2022 was $6.2 million, a decrease of $5.1 million relative to the same period in 2021 primarily due to the same factors as the decrease in normalized EBITDA as discussed above as well as higher depreciation and amortization expense and transaction costs of approximately $1.1 million incurred related to the Transaction.

Operating and administrative expense for the three months ended June 30, 2022 was $33.3 million, an increase of $6.3 million from the same period in 2021 mainly due to higher costs incurred to support business development activities, and transaction costs of approximately $1.1 million incurred related to the Transaction.

Depreciation and amortization expense for the three months ended June 30, 2022 was $11.5 million, an increase of $1.4 million from the same period in 2021 mainly due to a higher PP&E balance.

Interest expense for the three months ended June 30, 2022 was $7.5 million compared to $7.0 million in the same period in 2021. The increase of $0.5 million was mainly due to a higher average debt balance outstanding.

Income tax expense for the three months ended June 30, 2022 was $0.1 million, compared to income tax expense of $0.3 million in the same period in 2021. The decrease in income tax expense was primarily due to lower taxable income as a result of higher capital cost allowance deductions and higher costs incurred on business development activities.

Normalized net loss for the three months ended June 30, 2022 was $1.2 million, compared to normalized net income of $3.5 million in the same period in 2021. The decrease in normalized net income was mainly due to the same factors as the decrease in normalized EBITDA discussed above, higher depreciation and amortization expense and higher interest expense, partially offset by lower income tax expense.

Net loss after taxes for the three months ended June 30, 2022 was $1.4 million, compared to net income after taxes of $4.0 million in the same period in 2021. The decrease in net income after taxes was primarily due to the same factors as the decrease in operating income discussed above and higher interest expense, partially offset by lower income tax expense.

Normalized funds from operations for the three months ended June 30, 2022 was $9.9 million, a decrease of $1.0 million relative to the same period in 2021, primarily due to lower normalized EBITDA discussed above, higher interest expense, and lower distributions from the Northwest Hydro Facilities, partially offset by lower current income tax expense.

Please refer to the "*Liquidity and Capital Resources - Liquidity*" section of this MD&A for a discussion of changes in cash from operating activities.

Six Months Ended June 30

Normalized EBITDA for the six months ended June 30, 2022 was $63.1 million, an increase of $0.3 million from the same period in 2021, mainly due to higher approved rates and rate base growth at the Utilities and colder weather in Nova Scotia compared to the same period in 2021, partially offset by lower revenues at the Bear Mountain Wind Park, lower normalized EBITDA from the Northwest Hydro Facilities, and higher operating and administrative expense.

Operating income for the six months ended June 30, 2022 was $38.6 million, a decrease of $4.0 million from the same period in 2021, mainly due to higher depreciation and amortization expense, and transaction costs of approximately $1.1 million incurred related to the Transaction, partially offset by the increase in Normalized EBITDA discussed above.

Operating and administrative expense for the six months ended June 30, 2022 was $63.0 million, an increase of $9.2 million from the same period in 2021, mainly due to higher costs incurred to support business development activities, and transaction costs of approximately $1.1 million incurred related to the Transaction.

Depreciation and amortization expense for the six months ended June 30, 2022 was $21.8 million, an increase of $2.5 million from the same period in 2021 mainly due to a higher PP&E balance.

Interest expense for the six months ended June 30, 2022 was $14.9 million compared to $13.9 million in the same period in 2021. The increase of $1.0 million was mainly due to a higher average debt balance outstanding.

Income tax recovery for the six months ended June 30, 2022 was $3.6 million, compared to income tax expense of $0.9 million in the same period in 2021. The decrease in income tax expense was primarily due to lower taxable income as a result of higher capital cost allowance deductions and higher costs incurred on business development activities.

Normalized net income for the six months ended June 30, 2022 was $28.2 million, an increase of $1.7 million relative to the same period in 2021 mainly due to lower income tax expense and the increase in normalized EBITDA discussed above, partially offset by higher depreciation and amortization expense and higher interest expense.

Net income after taxes for the six months ended June 30, 2022 was $27.3 million, a decrease of $0.5 million compared to the same period in 2021. The decrease was primarily due to the same factors as the decrease in operating income discussed above, lower unrealized gain on risk management contracts, and higher interest expense, partially offset by lower income tax expense.

Normalized funds from operations for the six months ended June 30, 2022 was $50.1 million, an increase of $4.2 million relative to the same period in 2021, primarily due to the increase in normalized EBITDA discussed above and lower current income tax expense, partially offset by lower distributions from the Northwest Hydro Facilities and higher interest expense.

Please refer to the "*Liquidity and Capital Resources - Liquidity*" section of this MD&A for a discussion of changes in cash from operating activities.

RESULTS BY REPORTING SEGMENT

Normalized EBITDA by Reporting Segment [(1)]

	Three Months Ended June 30		Six Months Ended June 30	
($ millions)	**2022**	2021	**2022**	2021
Utilities	**$ 19.7**	$ 16.9	**$ 62.2**	$ 55.0
Renewable Energy	**4.0**	5.9	**8.3**	9.4
Corporate	**(4.9)**	(0.9)	**(7.4)**	(1.6)
	$ 18.8	$ 21.9	**$ 63.1**	$ 62.8

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

Operating Income (Loss) by Reporting Segment

	Three Months Ended June 30		Six Months Ended June 30	
($ millions)	**2022**	2021	**2022**	2021
Utilities	**$ 10.5**	$ 9.1	**$ 43.8**	$ 40.5
Renewable Energy	**1.3**	3.2	**2.9**	3.8
Corporate	**(5.6)**	(1.0)	**(8.1)**	(1.7)
	$ 6.2	$ 11.3	**$ 38.6**	$ 42.6

UTILITIES SEGMENT REVIEW

Financial results

($ millions)	Three Months Ended June 30 **2022**	Three Months Ended June 30 2021	Six Months Ended June 30 **2022**	Six Months Ended June 30 2021
Revenue	**$ 82.0**	$ 64.1	**$ 239.1**	$ 182.2
Cost of sales	**(36.7)**	(22.4)	**(126.3)**	(78.0)
Operating and administrative expense	**(26.2)**	(24.9)	**(52.0)**	(49.5)
Normalized EBITDA from equity investment	**—**	—	**0.1**	0.1
Other income	**0.6**	0.1	**1.3**	0.2
Normalized EBITDA(1)	**$ 19.7**	$ 16.9	**$ 62.2**	$ 55.0
Unrealized gain (loss) on risk management contracts	**0.4**	0.5	**(0.3)**	1.3
Depreciation and amortization expense	**(9.6)**	(8.2)	**(18.1)**	(15.6)
Foreign exchange loss	**—**	(0.1)	**—**	(0.2)
Operating income	**$ 10.5**	$ 9.1	**$ 43.8**	$ 40.5

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

Operating statistics

	Three Months Ended June 30 **2022**	Three Months Ended June 30 2021	Six Months Ended June 30 **2022**	Six Months Ended June 30 2021
Natural gas deliveries - end-use (PJ)	**6.0**	5.5	**19.9**	18.8
Natural gas deliveries - transportation (PJ)	**1.3**	1.3	**3.0**	2.8
Degree day variance from normal - AUI (%)(1)	**5.6**	(1.1)	**(2.2)**	(2.1)
Degree day variance from normal - HGL (%)(1)	**(8.8)**	(10.4)	**(5.3)**	(9.6)

(1) A degree day for AUI and HGL is the cumulative extent to which the daily mean temperature falls below 15 degrees Celsius at AUI and 18 degrees Celsius at HGL. Normal degree days are based on a 20-year rolling average. Positive variances from normal lead to increased delivery volumes from normal expectations. Degree day variances do not materially affect the results of PNG, as the BCUC has approved a rate stabilization mechanism for its residential and small commercial customers.

Three Months Ended June 30

Revenue increased by $17.9 million for the three months ended June 30, 2022 as compared to the same period in 2021 primarily due to higher approved rates and rate base growth, colder weather in Alberta compared to the same period in 2021, and flow through of higher gas supply costs to customers.

Normalized EBITDA increased by $2.8 million for the three months ended June 30, 2022 as compared to the same period in 2021 primarily due to higher approved rates and rate base growth and colder weather in Alberta compared to the same period in 2021.

Operating income increased by $1.4 million for the three months ended June 30, 2022 as compared to the same period in 2021, primarily due to the same factors as the increase in normalized EBITDA discussed above, partially offset by higher depreciation and amortization expense.

Six Months Ended June 30

Revenue increased by $56.9 million for the six months ended June 30, 2022 as compared to the same period in 2021, primarily due to higher approved rates and rate base growth, colder weather compared to the same period in 2021 in Nova Scotia, and flow through of higher gas supply costs to customers.

Normalized EBITDA increased by $7.2 million for the six months ended June 30, 2022 as compared to the same period in 2021, primarily due to higher approved rates and rate base growth and colder weather compared to the same period in 2021 in Nova Scotia.

Operating income increased by $3.3 million for the six months ended June 30, 2022 as compared to the same period in 2021, primarily due to the same factors as the increased normalized EBITDA discussed above, partially offset by higher depreciation and amortization expense and an unrealized loss on risk management contracts compared to a gain in the same period in 2021.

RENEWABLE ENERGY SEGMENT REVIEW

Financial results

		Three Months Ended June 30			Six Months Ended June 30
($ millions)		**2022**	2021	**2022**	2021
Revenue		**$ 2.8**	$ 3.8	**$ 9.0**	$ 9.5
Cost of sales		**—**	(0.1)	**(0.2)**	(0.2)
Operating and administrative expense		**(1.2)**	(1.2)	**(2.6)**	(2.7)
Normalized EBITDA from equity investment		**2.4**	3.4	**2.1**	2.8
Normalized EBITDA(1)		**$ 4.0**	$ 5.9	**$ 8.3**	$ 9.4
Depreciation and amortization expense		**(1.8)**	(1.8)	**(3.6)**	(3.6)
Accretion expense		**(0.1)**	—	**(0.1)**	(0.1)
Accretion and depreciation and amortization expense from equity investment		**(0.8)**	(0.9)	**(1.7)**	(1.9)
Operating income		**$ 1.3**	$ 3.2	**$ 2.9**	$ 3.8

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

Operating statistics

	Three Months Ended June 30		Six Months Ended June 30	
	2022	2021	**2022**	2021
Bear Mountain Wind Park power sold (GWh)	**25.9**	33.9	**84.0**	89.2
Northwest Hydro Facilities power sold (GWh)(1)	**35.8**	37.0	**40.6**	41.1

(1) Representing 10 percent of the total power sold by the Northwest Hydro Facilities.

Three Months Ended June 30

Revenue decreased by $1.0 million for the three months ended June 30, 2022 as compared to the same period in 2021 primarily due to lower wind generation at the Bear Mountain Wind Park and lower sales of renewable energy certificates ("RECs"), partially offset by annual price escalation.

Normalized EBITDA decreased by $1.9 million for the three months ended June 30, 2022 as compared to the same period in 2021 primarily due to lower revenues at the Bear Mountain Wind Park and lower normalized EBITDA from the investment in the Northwest Hydro Facilities.

Operating income decreased by $1.9 million for the three months ended June 30, 2022 as compared to the same period in 2021 due to the same factors as the decrease in normalized EBITDA discussed above.

During the three months ended June 30, 2022, TSU recorded $1.6 million of equity income from its investment in the Northwest Hydro Facilities, compared to $2.5 million in the same period in 2021. The decrease in equity income was mainly due to the absence of the BC Hydro arbitration settlement during the second quarter of 2021 and lower generation at the Northwest Hydro Facilities compared to the same period in 2021, partially offset by annual price escalation.

Six Months Ended June 30

Revenue decreased by $0.5 million for the six months ended June 30, 2022 as compared to the same period in 2021, primarily due to lower sales of RECs and lower generation at the Bear Mountain Wind Park, partially offset by annual price escalation.

Normalized EBITDA decreased by $1.1 million for the six months ended June 30, 2022 as compared to the same period in 2021, primarily due to lower revenues at the Bear Mountain Wind Park and lower normalized EBITDA from the Northwest Hydro Facilities.

Operating income decreased by $0.9 million for the six months ended June 30, 2022 as compared to the same period in 2021 due to the same factors as the decrease in normalized EBITDA discussed above.

During the six months ended June 30, 2022, TSU recorded $0.4 million of equity income from its investment in the Northwest

Hydro Facilities, compared to $0.9 million in the same period in 2021. The decrease in equity income was mainly due to the absence of the BC Hydro arbitration settlement during the second quarter of 2021, partially offset by annual price escalation.

CORPORATE SEGMENT REVIEW

	Three Months Ended June 30		Six Months Ended June 30	
($ millions)	**2022**	2021	**2022**	2021
Operating and administrative expense	**$ (4.8)**	$ (0.9)	**$ (7.3)**	$ (1.6)
Normalized EBITDA from equity investment	**(0.1)**	—	**(0.1)**	—
Normalized EBITDA[1]	**$ (4.9)**	$ (0.9)	**$ (7.4)**	$ (1.6)
Depreciation and amortization	**(0.1)**	(0.1)	**(0.1)**	(0.1)
Unrealized gain on risk management contracts	**0.5**	—	**0.5**	—
Transaction costs	**(1.1)**	—	**(1.1)**	—
Operating loss	**$ (5.6)**	$ (1.0)	**$ (8.1)**	$ (1.7)

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

Expenses incurred by the Corporate segment are primarily associated with providing shared corporate services and business development. For the three and six months ended June 30, 2022, normalized EBITDA was a loss of $4.9 and $7.4 million, respectively (2021 - $0.9 and $1.6 million, respectively). The decrease in normalized EBITDA for the three and six months ended June 30, 2022, compared to the same periods in 2021 was primarily due to higher costs incurred to support business development activities and higher salaries and wages.

For the three and six months ended June 30, 2022, corporate costs of $1.7 million and $4.1 million, respectively, were allocated to TSU's operating segments compared to $1.6 million and $3.3 million, respectively, for the same periods in 2021.

For the three and six months ended June 30, 2022, operating loss was $5.6 million and $8.1 million, respectively (2021 - $1.0 million and $1.7 million, respectively). The increase in operating loss was due to the same factors as the variance in normalized EBITDA discussed above and transaction costs of approximately $1.1 million incurred related to the Transaction, partially offset by an unrealized gain on the deal contingent forward starting interest rate swap that the Company entered into in connection with the Transaction.

SUMMARY OF SELECTED QUARTERLY RESULTS[1]

The following table sets forth unaudited quarterly information for each of the eight quarters from the quarter ended September 30, 2020 to the quarter ended June 30, 2022.

($ millions, except per Common Share amounts)	**Q2-22**	Q1-22	Q4-21	Q3-21
Revenue	**84.8**	163.3	130.8	54.6
Normalized net income (loss)[2]	**(1.2)**	29.3	20.9	1.7
Net income (loss) after taxes	**(1.4)**	28.7	21.0	2.4
Net income (loss) after taxes per Common Share - basic and diluted ($)	**(0.05)**	0.96	0.70	0.08
Dividends declared per Common Share ($)[3]	**0.2925**	0.2925	0.2925	0.2750

($ millions, except per Common Share amounts)	Q2-21	Q1-21	Q4-20	Q3-20
Revenue	67.9	123.9	99.8	48.6
Normalized net income[2]	3.5	23.1	17.4	1.0
Net income after taxes	4.0	23.9	15.5	0.5
Net income after taxes per Common Share - basic and diluted ($)	0.13	0.80	0.52	0.02
Dividends declared per Common Share ($)[3]	0.2750	0.2750	0.2750	0.2600

(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.

(3) TSU declares and pays a quarterly dividend on its Common Shares. 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 TSU.

Quarter-over-quarter financial results are impacted by seasonality, weather, planned and unplanned outages, and timing and recognition of regulatory decisions.

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

Net income after taxes is affected by non-cash items such as deferred income tax, depreciation and amortization expense, accretion expense, impairment, gains and losses on foreign exchange contracts, and gains or losses on the sale of assets. For these reasons, net income may not necessarily reflect the same trends as revenue. In addition, the equity investment in the Northwest Hydro Facilities is impacted by seasonal precipitation, which creates periods of high river flow, typically during May through October of any given year.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

The Company's primary sources of liquidity are cash flow from operations and debt additions. The Company's cash requirements include funding for capital expenditures and working capital, servicing and repaying long-term debt, and dividend payments. The Company's sources and uses of cash are further discussed below:

	Three Months Ended June 30		Six Months Ended June 30	
($ millions)	**2022**	2021	**2022**	2021
Cash from operations	**$ 14.4**	$ 26.2	**$ 59.0**	$ 63.7
Cash used in investing activities	**(22.0)**	(17.4)	**(45.4)**	(33.4)
Cash from (used in) financing activities	**2.5**	(13.3)	**(11.3)**	(34.2)
Increase (decrease) in cash and cash equivalents	**$ (5.1)**	$ (4.5)	**$ 2.3**	$ (3.9)

Cash from operations

During the three months ended June 30, 2022, cash from operations decreased by $11.8 million as compared to the same period in 2021 primarily due to lower cash earnings, unfavourable variance from changes in operating assets and liabilities and lower distributions from the investment in the Northwest Hydro Facilities. The unfavourable variance in changes in operating assets and liabilities were primarily due to timing of supplier payments.

During the six months ended June 30, 2022, cash from operations decreased by $4.7 million as compared to the same period in 2021 primarily due to unfavourable variance from changes in operating assets and liabilities, and lower distributions from the investment in the Northwest Hydro Facilities, partially offset by higher cash earnings. The unfavourable variance in changes in operating assets and liabilities were mainly due to timing of supplier payments.

Investing activities

During the three and six months ended June 30, 2022, cash used in investing activities increased by $4.6 million and $12.0 million, respectively, as compared to the same periods in 2021 primarily due to higher capital expenditures and a contribution of $1.2 million to the NGIF Cleantech Ventures Limited Partnership.

See also the "*Capital Expenditures*" section of this MD&A.

Financing activities

During the three months ended June 30, 2022, cash from financing activities increased by $15.8 million as compared to the same period in 2021 primarily due to higher debt borrowings, partially offset by an increase in dividends paid.

During the six months ended June 30, 2022, cash used in financing activities decreased by $22.9 million as compared to the same period in 2021 primarily due to higher debt borrowings, partially offset by an increase in dividends paid.

Working Capital

($ millions except current ratio)		**June 30, 2022**		December 31, 2021
Current assets	**$**	**83.6**	$	110.3
Current liabilities		**132.3**		109.8
Working capital	**$**	**(48.7)**	$	0.5
Working capital ratio		**0.63**		1.00

The variation in the working capital was primarily due to an increase in cash held and a decrease in accounts payable. TSU's working capital will fluctuate in the normal course of business, and the working capital deficiency will be funded using cash flow from operations and available credit facilities as required.

Capital Resources

The Company's objective for managing capital is to maintain its investment grade credit rating, ensure adequate liquidity, maximize the profitability of its existing assets and grow its business through prudent capital investments which ultimately add to the utilities' rate base, and enhance returns to its shareholder. The Company's capital resources are comprised of short-term and long-term debt (including the current portion).

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

($ millions, except where noted)		**June 30, 2022**		December 31, 2021
Short-term debt	**$**	**24.4**	$	—
Current portion of long-term debt		**26.0**		1.0
Long-term debt(1)		**730.8**		773.4
Total debt		**781.2**		774.4
Less: cash and cash equivalents		**(8.2)**		(5.9)
Net debt(2)	**$**	**773.0**	$	768.5
Shareholders' equity		**638.0**		628.3
Total capitalization	**$**	**1,411.0**	$	1,396.8
Net debt-to-total capitalization(2) (%)		**54.8**		55.0

(1) Net of debt issuance costs of $2.6 million as of June 30, 2022 (December 31, 2021 - $3.0 million).

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

As at June 30, 2022, TSU's total debt primarily consisted of outstanding MTNs of $650 million (December 31, 2021 - $650 million), PNG debentures of $23.0 million (December 31, 2021 - $23.0 million) and $110.4 million drawn under other bank credit facilities (December 31, 2021 - $104.0 million). In addition, TSU had $11.0 million of letters of credit issued (December 31, 2021 - $8.3 million).

TSU's earnings interest coverage for the rolling 12 months ended June 30, 2022 was 2.7 times (12 months ended June 30, 2021 2.7 times).

Credit Facilities

The Company funds its long and short term borrowing requirements with credit facilities as follows:

($ millions)		**Borrowing capacity**		**Drawn at June 30, 2022**		Drawn at December 31, 2021
Syndicated revolving credit facility(1)	$	**200.0**	**$**	**61.0**	$	79.0
Operating credit facility(2)		**35.0**		**26.0**		3.2
PNG committed credit facility(3)		**25.0**		**25.0**		25.0
PNG operating credit facility(4)		**25.0**		**9.4**		5.1
	$	**285.0**	**$**	**121.4**	$	112.3

(1) On October 25, 2018, the Company entered into definitive credit agreements establishing the $200 million unsecured syndicated revolving credit facility. On July 16, 2021, the Company amended the facility and extended the maturity date to July 16, 2025. Borrowing options under this facility include Canadian prime rate-based loans, U.S. base rate loans, bankers' acceptances and LIBOR loans. Borrowings against this credit facility bear fees and interest at rates relevant to the nature of the draw made and the Company's credit rating. There are no mandatory repayments prior to maturity under this facility. The facility has covenants customary for these types of facilities, which must be met at each quarter end. The Company has complied with all financial covenants each quarter since the establishment of this facility.

(2) On October 25, 2018, the Company entered into a definitive credit agreement with a Canadian chartered bank establishing the $35 million revolving operating credit facility. Borrowings under this facility are due on demand. Borrowing options under this facility include overdraft, letters of credit, Canadian prime rate-based loans, U.S. base rate loans, bankers' acceptances and LIBOR loans. Borrowings on this credit facility bear fees and interest at rates relevant to the nature of the draw made and the Company's credit rating. This facility is used to fund overdraft amounts and to issue letters of credit. As at June 30, 2022 a total of $6.0 million (December 31, 2021 - $3.2 million) in letters of credit were issued and are outstanding. This facility has covenants customary for these types of facilities, which must be met at each quarter end. The Company has complied with all financial covenants each quarter since the establishment of this facility.

(3) PNG has $55 million of revolving credit facilities maturing on May 4, 2023, $30 million of which is with the Company and $25 million of which is with a Canadian chartered bank. The $25 million external facility will be used to support PNG's capital spending program. Borrowings under the external facility are available by way of bankers' acceptances bearing interest at the three-month bankers' acceptance rate plus a spread and subject to stand-by fees. Interest and stand-by costs are due monthly. Optional repayments are allowed without penalty and there is no mandatory repayment prior to maturity. The facilities have covenants customary for these types of facilities, which must be met at each quarter end. PNG has been in compliance with all financial covenants each quarter since the establishment of these facilities.

(4) PNG has a $25 million operating credit facility with a Canadian chartered bank maturing on November 4, 2022. The operating line is available for working capital purposes through cash draws in the form of prime-rate advances or bankers' acceptances and the issuance of letters of credit and is collateralized by a charge on PNG's accounts receivable and inventories. As at June 30, 2022, $5.0 million (December 31, 2021 - $5.1 million) of letters of credit were issued and outstanding under this facility.

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

Ratios	**Debt covenant Requirements** (3)	**As at June 30, 2022**
Bank debt-to-capitalization(1)(2)	not greater than 65 percent	**54.5%**

(1) Calculated in accordance with the Company's credit facility agreements, which are available on SEDAR at *www.sedar.com*.

(2) Estimated, subject to final adjustments.

(3) On July 16, 2021, the unsecured syndicated revolving credit facility was amended to only require the Consolidated EBITDA to Interest Expense covenant of not less than 2.5x to be reported if TSU's credit rating is below BBB (low) or equivalent.

Base Shelf Prospectus

On November 16, 2020, the Company filed a $1.0 billion base shelf prospectus. The purpose of the base shelf prospectus is to facilitate timely offerings of certain types of future public debt and/or equity issuances during the 25-month period that the base shelf prospectus remains effective. As at June 30, 2022, $1.0 billion was available under the base shelf prospectus.

CAPITAL EXPENDITURES

	Three Months Ended June 30, 2022				Three Months Ended June 30, 2021			
($ millions)	**Renewable Energy**	**Utilities**	**Corporate**	**Total**	Renewable Energy	Utilities	Corporate	Total
Capital expenditures:								
PP&E	**$ —**	**$ 25.5**	**$ 0.1**	**$ 25.6**	$ —	$ 16.0	$ —	$ 16.0
Intangible assets	**—**	**0.4**	**—**	**0.4**	—	3.5	0.1	3.6
Capital expenditures	**—**	**25.9**	**0.1**	**26.0**	—	19.5	0.1	19.6
Disposals:								
PP&E	**—**	**—**	**—**	**—**	—	(0.1)	—	(0.1)
Net capital expenditures	**$ —**	**$ 25.9**	**$ 0.1**	**$ 26.0**	$ —	$ 19.4	$ 0.1	$ 19.5

($ millions)	Six Months Ended June 30, 2022 Renewable Energy	Utilities	Corporate	Total	Six Months Ended June 30, 2021 Renewable Energy	Utilities	Corporate	Total
Capital expenditures:								
PP&E	$ —	$ 38.8	$ 0.1	$ 38.9	$ —	$ 25.2	$ —	$ 25.2
Intangible assets	—	0.8	—	0.8	—	4.8	0.1	4.9
Capital expenditures	—	39.6	0.1	39.7	—	30.0	0.1	30.1
Disposals:								
PP&E	—	(0.1)	—	(0.1)	—	(0.1)	—	(0.1)
Net capital expenditures	$ —	$ 39.5	$ 0.1	$ 39.6	$ —	$ 29.9	$ 0.1	$ 30.0

Capital expenditures for the three and six months ended June 30, 2022 were $26.0 million and $39.7 million, respectively, compared to $19.6 million and $30.1 million, respectively for the three and six months ended June 30, 2021. The increase in capital expenditures was mainly due to higher capital spending at PNG, partially offset by lower software development costs.

RISK MANAGEMENT

TSU is exposed to various market risks in the normal course of operations that could impact earnings and cash flows. The Board of Directors provides oversight of the Company's risk management activities. There have been no significant changes during the six months ended June 30, 2022, to the Company's business risks that were disclosed in the 2021 Annual MD&A. Please see note 10 to the Interim Financial Statements for details on the Company's financial instruments.

SHARE INFORMATION

	As at July 26, 2022
Issued and outstanding	
Common Shares	30,000,000

ADOPTION OF NEW ACCOUNTING STANDARDS

The Company did not adopt any new Accounting Standards Updates ("ASU") issued by FASB during the six months ended June 30, 2022.

FUTURE CHANGES IN ACCOUNTING PRINCIPLES

In June 2016, FASB issued ASU No. 2016-13 "Financial Instruments – Credit Losses: Measurement of Credit Losses on Financial Instruments". The amendments in this ASU replace the current "incurred loss" impairment methodology with an "expected loss" model for financial assets measured at amortized cost. In November 2019, FASB issued ASU No. 2019-10 "Financial Instruments – Credit Losses (Topic 326), Derivatives and Hedging (Topic 815) and Leases (Topic 842): Effective Dates" which deferred the effective date of ASU No. 2016-13 to January 1, 2023. Early adoption is permitted. The Company is currently completing its assessment of the impact of these ASUs on its consolidated financial statements.

OFF-BALANCE SHEET ARRANGEMENTS

The Company has long-term natural gas purchase and transportation arrangements, service agreements, and operating and finance leases, all of which are transacted at market prices and in the normal course of business. TSU did not enter into any material off-balance sheet arrangements during the six months ended June 30, 2022 other than as disclosed under note 12 to the Interim Financial Statements. Reference should be made to the 2021 Annual Financial Statements.

DISCLOSURE CONTROLS AND PROCEDURES (“DC&P”) AND INTERNAL CONTROL OVER FINANCIAL REPORTING (“ICFR”)

The Company is a “Venture Issuer” under applicable Canadian securities regulations for certain purposes. As such, the Chief Executive Officer (“CEO”) and Chief Financial Officer (“CFO”) are not required to certify the design and evaluation of the Company’s DC&P and ICFR under National Instrument 52-109 – *Certification of Disclosure in Issuers’ Annual and Interim Filings*. However, the CEO and CFO have reviewed the Interim Financial Statements and this MD&A. Based on their knowledge and exercise of reasonable diligence, they have concluded that these documents fairly present in all material respects the financial condition, financial performance and cash flows of the Company as at the date of and for the periods presented.

NON-GAAP FINANCIAL MEASURES

This MD&A contains references to certain financial measures used by the Company that do not have a standardized meaning prescribed by U.S. 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 U.S. GAAP. The non-GAAP measures and their reconciliation to U.S. GAAP financial measures are shown below. These non-GAAP measures provide additional information that management believes is meaningful in describing the Company’s 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 (loss), normalized net income (loss) per share, normalized funds from operations, normalized funds from operations per share, net debt and net debt to total capitalization throughout this MD&A have the meanings as set out in this section.

Normalized EBITDA

	Three Months Ended June 30		Six Months Ended June 30	
($ millions)	**2022**	2021	**2022**	2021
Normalized EBITDA	**$ 18.8**	$ 21.9	**$ 63.1**	$ 62.8
Add (deduct):				
Foreign exchange loss	**—**	(0.1)	**—**	(0.2)
Unrealized gain on risk management contracts	**0.9**	0.5	**0.2**	1.3
Accretion expense	**(0.1)**	—	**(0.1)**	(0.1)
Depreciation and amortization expense	**(11.5)**	(10.1)	**(21.8)**	(19.3)
Accretion and depreciation and amortization expense from equity investment	**(0.8)**	(0.9)	**(1.7)**	(1.9)
Transaction costs	**(1.1)**	—	**(1.1)**	—
Operating income	**$ 6.2**	$ 11.3	**$ 38.6**	$ 42.6

Normalized EBITDA is a measure of the Company’s operating profitability prior to how business activities are financed, assets are amortized, or earnings are taxed. Normalized EBITDA is calculated using operating income adjusted for depreciation and amortization expense, accretion expense, foreign exchange gain (loss), unrealized gain (loss) on risk management contracts, and other typically non-recurring items such as the transaction costs associated with the pending acquisition of the Alaska Utilities Business. Normalized EBITDA is frequently used by 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 EBITDA as presented should not be viewed as an alternative to operating income or other measures of income calculated in accordance with U.S. GAAP as an indicator of performance.

Normalized Net Income (Loss) and Normalized Net Income (Loss) per Share

($ millions)	Three Months Ended June 30 2022	Three Months Ended June 30 2021	Six Months Ended June 30 2022	Six Months Ended June 30 2021
Normalized net income (loss)	**$ (1.2)**	$ 3.5	**$ 28.2**	$ 26.5
Add (deduct) after-tax:				
Unrealized gain on risk management contracts	**0.9**	0.5	**0.2**	1.3
Transaction costs	**(1.1)**	—	**(1.1)**	—
Net income (loss) after taxes	**$ (1.4)**	$ 4.0	**$ 27.3**	$ 27.8

Normalized net income (loss) represents net income (loss) after taxes adjusted for the after tax impact of unrealized gain (loss) on risk management contracts and other typically non-recurring items such as the transaction costs associated with the pending acquisition of the Alaska Utilities Business. Normalized net income (loss) per share is calculated by dividing normalized net income (loss) by the weighted average number of common shares. This measure is presented in order to enhance the comparability of results, as it reflects the underlying performance of the Company.

Normalized net income (loss) and normalized net income (loss) per share as presented should not be viewed as an alternative to net income (loss) after taxes or other measures of income calculated in accordance with U.S. GAAP as an indicator of performance.

Normalized Funds from Operations and Normalized Funds from Operations per Share

($ millions)	Three Months Ended June 30 2022	Three Months Ended June 30 2021	Six Months Ended June 30 2022	Six Months Ended June 30 2021
Normalized funds from operations	**$ 9.9**	$ 10.9	**$ 50.1**	$ 45.9
Add (deduct):				
Changes in operating assets and liabilities	**5.6**	15.3	**10.0**	17.8
Transaction costs	**(1.1)**	—	**(1.1)**	—
Cash from operations	**$ 14.4**	$ 26.2	**$ 59.0**	$ 63.7

Normalized funds from operations is used to assist management and investors in analyzing the liquidity of the Company without regard to changes in operating assets and liabilities in the period as well as other non-operating related income and expenses such as the transaction costs associated with the pending acquisition of the Alaska Utilities Business. Management uses this measure to understand the ability to generate funds for use in investing and financing activities.

Normalized funds from operations per share is calculated by dividing normalized funds from operations by the weighted average number of common shares.

Normalized funds from operations and normalized funds from operations per share as presented should not be viewed as an alternative to cash from operations or other cash flow measures calculated in accordance with U.S. GAAP as an indicator of liquidity.

Net Debt and Net Debt to Total Capitalization

Net debt and net debt to total capitalization are used by the Company to monitor its capital structure and financing requirements. It is also used as a measure of the Company's overall financial strength. Net debt is defined as short-term debt, 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. Additional information regarding these non-GAAP measures can be found under the *"Liquidity and Capital Resources – Capital Resources"* section of this MD&A.

DEFINITIONS

AUC	Alberta Utilities Commission
BCUC	British Columbia Utilities Commission
GCOC	Generic Cost of Capital
GJ	Gigajoule
GW	Gigawatt
GWh	Gigawatt hour
MTN	Medium-term note
PJ	Petajoule; one million gigajoules
PP&E	Property, plant and equipment

ABOUT TSU

TSU is a Canadian company with natural gas distribution utilities and renewable power generation assets. TSU serves approximately 133,000 customers, delivering low carbon energy, safely and reliably. For more information visit: www.trisummit.ca

Condensed Consolidated Balance Sheets *(unaudited)*

As at *($ millions)*		**June 30, 2022**		December 31, 2021
ASSETS				
Current assets				
Cash and cash equivalents	**$**	**8.2**	$	5.9
Accounts receivable, net of allowances		**54.0**		90.4
Inventory		**3.9**		3.0
Regulatory assets		**11.1**		5.2
Risk management contract assets *(note 10)*		**2.1**		1.2
Prepaid expenses and other current assets		**4.3**		4.6
		83.6		110.3
Property, plant and equipment		**1,119.6**		1,099.6
Intangible assets		**39.0**		41.1
Goodwill		**119.1**		119.1
Regulatory assets		**254.5**		252.4
Risk management contract assets *(note 10)*		**2.8**		—
Other long-term assets		**12.2**		12.7
Investments accounted for by the equity method *(note 5)*		**115.1**		113.5
	$	**1,745.9**	$	1,748.7
LIABILITIES AND SHAREHOLDER'S EQUITY				
Current liabilities				
Accounts payable and accrued liabilities	**$**	**62.7**	$	88.2
Short-term debt *(note 6)*		**24.4**		—
Current portion of long-term debt *(note 7)*		**26.0**		1.0
Customer deposits		**8.2**		10.5
Regulatory liabilities		**8.1**		7.3
Risk management contract liabilities *(note 10)*		**1.2**		0.5
Other current liabilities		**1.7**		2.3
		132.3		109.8
Long-term debt *(note 7)*		**730.8**		773.4
Asset retirement obligations		**4.9**		4.8
Deferred income taxes *(note 9)*		**161.3**		156.1
Regulatory liabilities		**50.9**		47.4
Lease liabilities		**5.8**		6.2
Future employee obligations *(note 11)*		**21.9**		22.7
	$	**1,107.9**	$	1,120.4
Shareholder's equity				
Common shares, no par value, unlimited shares authorized; June 30, 2022 and December 31, 2021 - 30 million shares issued and outstanding		**321.0**		321.0
Contributed surplus		**100.0**		100.0
Retained earnings		**218.7**		209.0
Accumulated other comprehensive loss		**(1.7)**		(1.7)
		638.0		628.3
	$	**1,745.9**	$	1,748.7

Commitments, contingencies and guarantees *(note 12)*

Subsequent events *(note 16)*

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Consolidated Statements of Income (Loss) *(unaudited)*

($ millions)	Three months ended June 30 2022	2021	Six months ended June 30 2022	2021
REVENUE *(note 8)*	**$ 84.8**	$ 67.9	**$ 248.1**	$ 191.7
EXPENSES				
Cost of sales, exclusive of items shown separately	**36.7**	22.5	**126.5**	78.2
Operating and administrative	**33.3**	27.0	**63.0**	53.8
Accretion	**0.1**	—	**0.1**	0.1
Depreciation and amortization	**11.5**	10.1	**21.8**	19.3
	81.6	59.6	**211.4**	151.4
Income from equity investments	**1.5**	2.5	**0.4**	1.0
Unrealized gain on risk management contracts *(note 10)*	**0.9**	0.5	**0.2**	1.3
Other income	**0.6**	0.1	**1.3**	0.2
Foreign exchange loss	**—**	(0.1)	**—**	(0.2)
Operating income	**6.2**	11.3	**38.6**	42.6
Interest expense				
Short-term debt	**(0.1)**	(0.1)	**(0.2)**	(0.2)
Long-term debt	**(7.4)**	(6.9)	**(14.7)**	(13.7)
Income (loss) before income taxes	**(1.3)**	4.3	**23.7**	28.7
Income tax expense (recovery) *(note 9)*				
Current	**(1.1)**	0.4	**(3.9)**	0.4
Deferred	**1.2**	(0.1)	**0.3**	0.5
Net income (loss) after taxes	**$ (1.4)**	$ 4.0	**$ 27.3**	$ 27.8

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Consolidated Statements of Comprehensive Income (Loss) *(unaudited)*

($ millions)	Three months ended June 30 2022	2021	Six months ended June 30 2022	2021
Net income (loss) after taxes	**$ (1.4)**	$ 4.0	**$ 27.3**	$ 27.8
Other comprehensive loss, net of taxes	**—**	—	**—**	—
Comprehensive income (loss), net of taxes	**$ (1.4)**	$ 4.0	**$ 27.3**	$ 27.8

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Consolidated Statements of Changes in Equity *(unaudited)*

($ millions)	Three months ended June 30 **2022**	Three months ended June 30 2021	Six months ended June 30 **2022**	Six months ended June 30 2021
Common shares				
Balance, beginning of period	**$ 321.0**	$ 321.0	**$ 321.0**	$ 321.0
Balance, end of period	**$ 321.0**	$ 321.0	**$ 321.0**	$ 321.0
Contributed surplus				
Balance, beginning of period	**$ 100.0**	$ 100.0	**$ 100.0**	$ 100.0
Balance, end of period	**$ 100.0**	$ 100.0	**$ 100.0**	$ 100.0
Retained earnings				
Balance, beginning of period	**$ 228.9**	$ 206.9	**$ 209.0**	$ 191.3
Net income (loss) after taxes	**(1.4)**	4.0	**27.3**	27.8
Common share dividends	**(8.8)**	(8.3)	**(17.6)**	(16.5)
Balance, end of period	**$ 218.7**	$ 202.6	**$ 218.7**	$ 202.6
Accumulated other comprehensive loss				
Balance, beginning of period	**$ (1.7)**	$ (2.7)	**$ (1.7)**	$ (2.7)
Balance, end of period	**$ (1.7)**	$ (2.7)	**$ (1.7)**	$ (2.7)
Total shareholder's equity	**$ 638.0**	$ 620.9	**$ 638.0**	$ 620.9

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Consolidated Statements of Cash Flows *(unaudited)*

($ millions)	Three months ended 2022	June 30 2021	Six months ended 2022	June 30 2021
Cash from operations				
Net income (loss) after taxes	**$ (1.4)**	$ 4.0	**$ 27.3**	$ 27.8
Items not involving cash:				
Depreciation and amortization expense	**11.5**	10.1	**21.8**	19.3
Accretion expense	**0.1**	—	**0.1**	0.1
Deferred income tax expense (recovery) *(note 9)*	**1.2**	(0.1)	**0.3**	0.5
Income from equity investments	**(1.5)**	(2.5)	**(0.4)**	(1.0)
Unrealized gain on risk management contracts *(note 10)*	**(0.9)**	(0.5)	**(0.2)**	(1.3)
Other	**(0.2)**	(0.7)	**0.1**	(0.7)
Distributions from equity investments	**—**	0.6	**—**	1.2
Changes in operating assets and liabilities *(note 13)*	**5.6**	15.3	**10.0**	17.8
	$ 14.4	$ 26.2	**$ 59.0**	$ 63.7
Investing activities				
Additions to property, plant and equipment	**(20.3)**	(13.8)	**(42.1)**	(28.0)
Additions to intangible assets	**(0.5)**	(3.6)	**(2.2)**	(5.4)
Proceeds from disposition of assets, net of transaction costs	**—**	0.1	**0.1**	0.1
Contributions to equity investments	**(1.2)**	(0.1)	**(1.2)**	(0.1)
	$ (22.0)	$ (17.4)	**$ (45.4)**	$ (33.4)
Financing activities				
Net proceeds from (repayment of) short-term debt	**24.4**	3.5	**24.4**	(0.7)
Net repayment of bankers' acceptances	**(13.1)**	(8.5)	**(18.1)**	(17.0)
Common share dividends	**(8.8)**	(8.3)	**(17.6)**	(16.5)
	$ 2.5	$ (13.3)	**$ (11.3)**	$ (34.2)
Change in cash and cash equivalents	**(5.1)**	(4.5)	**2.3**	(3.9)
Cash and cash equivalents, beginning of period	**13.3**	7.7	**5.9**	7.1
Cash and cash equivalents, end of period	**$ 8.2**	$ 3.2	**$ 8.2**	$ 3.2

See accompanying notes to the condensed interim consolidated financial statements.

1. OVERVIEW OF THE COMPANY

TriSummit Utilities Inc. ("TSU" or the "Company") is incorporated under the Canada Business Corporations Act and its registered office and principal place of business is in Calgary, Alberta. TSU is a wholly owned subsidiary of TriSummit Cycle Inc., a company in which the Public Sector Pension Investment Board indirectly holds a majority economic interest and Alberta Investment Management Corporation holds a minority economic interest.

The Company owns and operates rate-regulated distribution and transmission utility businesses through its wholly-owned subsidiaries Apex Utilities Inc. ("AUI") in Alberta, Pacific Northern Gas Ltd. ("PNG") and Pacific Northern Gas (N.E.) Ltd. ("PNG(N.E.)") in British Columbia and Heritage Gas Limited ("HGL") in Nova Scotia. The Company also owns the Bear Mountain Wind Park, an approximately 10 percent indirect interest in the Northwest Hydro Facilities, and a 33.33 percent equity interest in the utility that delivers natural gas to end-users in Inuvik, Northwest Territories.

2. BASIS OF PRESENTATION

Basis of Preparation

These condensed interim consolidated financial statements ("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"), U.S. GAAP reporting is permitted by Canadian securities laws for companies subject to reporting obligations under U.S. securities laws. However, given that the Company is not subject to such reporting obligations and could not therefore rely on the provisions of NI 52-107 to that effect, the Company sought and obtained exemptive relief from the securities regulators in Alberta and Ontario to permit it to prepare its financial statements in accordance with U.S. GAAP. The exemption will terminate on or after the earlier of January 1, 2024, the date upon which the Company ceases to have activities subject to rate regulation, or the effective date prescribed for the mandatory application of a standard within International Financial Reporting Standards specific to entities with activities subject to rate regulation.

In January 2021, the International Accounting Standards Board published the exposure draft *Regulatory Assets and Liabilities*, which would be applicable to entities with rate regulated activities. The effective date for mandatory application of the eventual final standard, if any, is not yet determinable and the Company continues to monitor the developments of the exposure draft and determine the potential impacts to the Company's financial statements.

Principles of Consolidation

The Financial Statements include the accounts of the Company and its direct and indirect subsidiaries, including, without limitation: TriSummit Utility Group Inc., Bear Mountain Wind Limited Partnership, TriSummit Canadian Energy Holdings Ltd., PNG, AUI, and HGL. The Financial Statements also include investments in Northwest Hydro Limited Partnership ("Coast LP"), Inuvik Gas Ltd., and NGIF Cleantech Ventures Limited Partnership, which are accounted for by the equity method. Intercompany transactions and balances are eliminated. Investments in unconsolidated companies that the Company has significant influence over, but not control, are accounted for using the equity method. In addition, the Company uses the equity method of accounting for investments in limited partnership interests in which it has more than a minor interest or influence over the partnership's operating and financial policies.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

USE OF ESTIMATES AND MEASUREMENT UNCERTAINTY

The preparation of these Financial Statements in accordance with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities, as well as the disclosure of contingent assets and liabilities. Key areas where management has made complex or subjective judgments, when matters are inherently uncertain, include but are not limited to: revenue recognition, credit loss estimates, depreciation and amortization rates, 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, provisions for income taxes, assumptions used to measure employee future benefits, provisions for contingencies, and carrying value of regulatory assets and liabilities. Certain estimates are necessary for the regulatory environment in which the Company operates, 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 Financial Statements of future periods.

SIGNIFICANT ACCOUNTING POLICIES

Except as noted below, these Financial Statements have been prepared following the same accounting policies and methods as those used in preparing the Company's 2021 annual audited consolidated financial statements.

FUTURE CHANGES IN ACCOUNTING PRINCIPLES

In June 2016, FASB issued ASU No. 2016-13 "Financial Instruments – Credit Losses: Measurement of Credit Losses on Financial Instruments". The amendments in this ASU replace the current "incurred loss" impairment methodology with an "expected loss" model for financial assets measured at amortized cost. In November 2019, FASB issued ASU No. 2019-10 "Financial Instruments – Credit Losses (Topic 326), Derivatives and Hedging (Topic 815) and Leases (Topic 842): Effective Dates" which deferred the effective date of ASU No. 2016-13 to January 1, 2023. Early adoption is permitted. The Company is currently completing its assessment of the impact of these ASUs on its Financial Statements.

4. PENDING ACQUISITION OF THE ALASKA UTILITIES BUSINESS

Effective May 25, 2022, the Company entered into a definitive agreement for a subsidiary of the Company to acquire 100 percent of ENSTAR Natural Gas Company ("ENSTAR") and the Alaska Pipeline Company, the Norstar Pipeline Company, Inc., and a 65 percent indirect interest in Cook Inlet Natural Gas Storage Alaska, LLC ("CINGSA") (collectively, the "Alaska Utilities Business") from a subsidiary of AltaGas Ltd. ("AltaGas"), in an all cash transaction (the "Transaction") valued at approximately US$800 million, subject to customary closing adjustments. As at March 31, 2022, CINGSA had approximately US$47 million (approximately US$31 million proportionate share) of outstanding senior notes, which TSU expects to remain in place. ENSTAR is the largest gas utility in the State of Alaska, servicing approximately 60 percent of the State's population, with approximately 150,000 customers and 3,626 miles of transmission and distribution pipeline. CINGSA, located in Kenai, Alaska, is the only commercial, fully contracted, state regulated gas storage facility in Alaska. Closing of the Transaction is subject to the satisfaction of certain customary closing conditions and certain regulatory and government approvals and clearances. The Transaction is expected to close no later than the first quarter of 2023.

5. INVESTMENTS ACCOUNTED FOR BY THE EQUITY METHOD

In March 2022, the Company subscribed for units of NGIF Cleantech Ventures Limited Partnership (the "Fund"). The Fund is operated by NGIF Capital Corp., a venture of the Canadian Gas Association, to support the funding of cleantech innovation in the natural gas value chain. As part of the subscription, the Company has committed to investing $5 million in the Fund over the next five years. The Company's investment in the Fund is accounted for using the equity method and as at June 30, 2022, the carrying value of the investment was $1.1 million.

6. SHORT-TERM DEBT

As at June 30, 2022, the Company held a $35.0 million (December 31, 2021 - $35.0 million) revolving operating credit facility with a Canadian chartered bank. Borrowings under this facility are due on demand. Draws on this facility are by way of overdraft, Canadian prime rate loans, U.S. base-rate loans, letters of credit, bankers' acceptances and LIBOR loans. As at June 30, 2022, the outstanding overdraft under this facility was $20.0 million (December 31, 2021 - $nil). Letters of credit outstanding under this facility as at June 30, 2022 were $6.0 million (December 31, 2021 - $3.2 million).

As at June 30, 2022, the Company held a $25.0 million (December 31, 2021 - $25.0 million) bank operating facility which is available for PNG's working capital purposes. The maturity date of this facility was extended to November 4, 2022. Draws on this facility are by way of prime-rate advances, bankers' acceptances or letters of credit at the bank's prime rate or for a fee. As at June 30, 2022, prime-rate advances under the operating facility were $4.4 million (December 31, 2021 - $nil million). Letters of credit outstanding under this facility as at June 30, 2022 were $5.0 million (December 31, 2021 - $5.1 million).

7. LONG-TERM DEBT

As at	Maturity date		**June 30, 2022**		December 31, 2021
Credit facilities					
$200 million unsecured revolving credit facility[a]	16-Jul-2025	**$**	**61.0**	$	79.0
$25 million PNG committed credit facility[b]	4-May-2023		**25.0**		25.0
Debenture notes					
PNG 2025 series debenture - 9.30 percent[c]	18-Jul-2025		**11.0**		11.0
PNG 2027 series debenture - 6.90 percent[c]	2-Dec-2027		**12.0**		12.0
Medium term notes					
$300 million senior unsecured - 4.26 percent	5-Dec-2028		**300.0**		300.0
$250 million senior unsecured - 3.15 percent	6-Apr-2026		**250.0**		250.0
$100 million senior unsecured - 3.13 percent	7-Apr-2027		**100.0**		100.0
Finance lease liabilities			**0.4**		0.4
		$	**759.4**	$	777.4
Less debt issuance costs and discount			**(2.6)**		(3.0)
		$	**756.8**	$	774.4
Less current portion			**(26.0)**		(1.0)
		$	**730.8**	$	773.4

(a) Borrowings on the credit facility can be by way of Canadian prime rate-based loans, U.S. base rate loans, bankers' acceptances and LIBOR loans.

(b) Borrowings on the credit facility can be by way of Canadian prime rate-based loans and bankers' acceptances.

(c) Collateral for the Secured Debentures consists of a specific first mortgage on substantially all of PNG's property, plant & equipment and gas purchase and gas sales contracts, and a first floating charge on other property, assets and undertakings.

8. REVENUE

The following table disaggregates revenue by major sources:

Three months ended June 30, 2022	**Renewable Energy**	**Utilities**	**Corporate**	**Total**
Revenue from contracts with customers				
Gas sales and transportation services	**$ —**	**$ 79.7**	**$ —**	**$ 79.7**
Other	**0.4**	**0.8**	**—**	**1.2**
Total revenue from contracts with customers	**$ 0.4**	**$ 80.5**	**$ —**	**$ 80.9**
Other sources of revenue				
Revenue from alternative revenue programs(a)	**$ —**	**$ 1.4**	**$ —**	**$ 1.4**
Leasing revenue(b)	**2.4**	**—**	**—**	**2.4**
Other	**—**	**0.1**	**—**	**0.1**
Total revenue from other sources	**$ 2.4**	**$ 1.5**	**$ —**	**$ 3.9**
Total revenue	**$ 2.8**	**$ 82.0**	**$ —**	**$ 84.8**

(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) Relates to power sold to BC Hydro under the power purchase agreement for the Bear Mountain Wind Park, which is accounted for as an operating lease. The lease revenue earned are from variable lease payments which are recorded when actual electricity is generated and delivered.

Six months ended June 30, 2022	**Renewable Energy**	**Utilities**	**Corporate**	**Total**
Revenue from contracts with customers				
Gas sales and transportation services	**$ —**	**$ 240.9**	**$ —**	**$ 240.9**
Other	**0.7**	**1.6**	**—**	**2.3**
Total revenue from contracts with customers	**$ 0.7**	**$ 242.5**	**$ —**	**$ 243.2**
Other sources of revenue				
Revenue from alternative revenue programs(a)	**$ —**	**$ (3.4)**	**$ —**	**$ (3.4)**
Leasing revenue(b)	**8.3**	**—**	**—**	**8.3**
Total revenue from other sources	**$ 8.3**	**$ (3.4)**	**$ —**	**$ 4.9**
Total revenue	**$ 9.0**	**$ 239.1**	**$ —**	**$ 248.1**

(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) Relates to power sold to BC Hydro under the power purchase agreement for the Bear Mountain Wind Park, which is accounted for as an operating lease. The lease revenue earned are from variable lease payments which are recorded when actual electricity is generated and delivered.

Three months ended June 30, 2021	Renewable Energy	Utilities	Corporate	Total
Revenue from contracts with customers				
Gas sales and transportation services	$ —	$ 61.5	$ —	$ 61.5
Other	0.3	0.5	—	0.5
Total revenue from contracts with customers	$ 0.3	$ 62.0	$ —	$ 62.0
Other sources of revenue				
Revenue from alternative revenue programs (a)	$ —	$ 1.4	$ —	$ 1.4
Leasing revenue(b)	3.5	—	—	3.8
Other	—	0.7	—	0.7
Total revenue from other sources	$ 3.5	$ 2.1	$ —	$ 5.9
Total revenue	$ 3.8	$ 64.1	$ —	$ 67.9

(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) Relates to power sold to BC Hydro under the power purchase agreement for the Bear Mountain Wind Park, which is accounted for as an operating lease. The lease revenue earned are from variable lease payments which are recorded when actual electricity is generated and delivered.

	Six months ended June 30, 2021			
	Renewable Energy	Utilities	Corporate	Total
Revenue from contracts with customers				
Gas sales and transportation services	$ —	$ 184.3	$ —	$ 184.3
Other	0.7	0.9	—	1.6
Total revenue from contracts with customers	$ 0.7	$ 185.2	$ —	$ 185.9
Other sources of revenue				
Revenue from alternative revenue programs[(a)]	$ —	$ (4.2)	$ —	$ (4.2)
Leasing revenue[(b)]	8.8	—	—	8.8
Other	—	1.2	—	1.2
Total revenue from other sources	$ 8.8	$ (3.0)	$ —	$ 5.8
Total revenue	$ 9.5	$ 182.2	$ —	$ 191.7

(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) Relates to power sold to BC Hydro under the power purchase agreement for the Bear Mountain Wind Park, which is accounted for as an operating lease. The lease revenue earned are from variable lease payments which are recorded when actual electricity is generated and delivered.

Accounts receivable as at June 30, 2022 include unbilled receivables of $13.9 million (December 31, 2021 - $48.8 million) related to gas sales and transportation services rendered to customers but not billed at period end.

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 at June 30, 2022:

	Remainder of 2022	**2023**	**2024**	**2025**	**2026**	**> 2026**	**Total**
Gas sales and transportation services	$ 7.4	$ 20.0	$ 18.3	$ 19.5	$ 19.3	$ 318.8	**$ 403.3**

The Company 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 the Company 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 gas sales and transportation service contracts contain variable consideration whereby uncertainty related to the associated variable consideration will be resolved (usually on a daily basis) as gas is delivered or as service is provided.

9. INCOME TAXES

For the three and six months ended June 30, 2022, the Company recognized an income tax expense of $0.1 million and income tax recovery of $3.6 million, respectively (three and six months ended June 30, 2021 – income tax expense of $0.3 million and $0.9 million, respectively). The decrease in the income tax expense for the three and six months ended June 30, 2022 was mainly due to lower taxable income as a result of higher capital cost allowance deductions and higher costs incurred to support business development activities.

10. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

The Company's financial instruments consist of accounts receivable, risk management contracts, accounts payable and accrued liabilities, short-term debt, current portion of long-term debt, and long-term debt. In addition, the Company entered into physical commodity contracts to manage exposure to fluctuations in commodity prices for its customers. Physical commodity contracts that meet the normal purchase and normal sale exemption are not recorded on the balance sheet at fair value and are recognized in the consolidated income statement when the contracts are settled.

Fair Value Hierarchy

The Company 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.

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. The Company uses derivative instruments to manage fluctuations in foreign exchange rates, natural gas prices and interest rates. The Company estimates forward prices based on observable market prices and rates from published sources.

Level 3 - fair values are based on inputs for the asset or liability that are not based on observable market data. The Company uses valuation techniques when observable market data is not available. The Company's level 3 derivatives include renewable energy physical purchase contracts with no observable market data. The Company uses comparable benchmark information and risk adjusted discount rates as inputs to estimate fair value for these derivatives.

Accounts receivable, accounts payable and accrued liabilities, and short-term debt - the carrying amounts approximate fair value because of the short maturity of these instruments.

					June 30, 2022
	Carrying Amount	Level 1	Level 2	Level 3	Total Fair Value
Financial assets					
Fair value through net income					
Risk management contract assets - current					
Foreign exchange contracts	$ 0.1	$ —	$ 0.1	$ —	$ 0.1
Interest rate swap	0.5	—	0.5	—	0.5
Commodity contracts	1.5	—	1.5	—	1.5
Fair value through regulatory assets and liabilities					
Risk management contract assets - non-current					
Commodity contracts	2.8	—	—	2.8	2.8
	$ 4.9	$ —	$ 2.1	$ 2.8	$ 4.9
Financial liabilities					
Fair value through net income					
Risk management contract liabilities - current					
Commodity contracts	$ 1.2	$ —	$ 1.2	$ —	$ 1.2
Amortized cost					
Current portion of long-term debt[(a)]	26.0	—	26.0	—	26.0
Long-term debt[(a)]	733.4	—	700.6	—	700.6
	$ 760.6	$ —	$ 727.8	$ —	$ 727.8

(a) Excludes deferred financing costs and debt discount.

					December 31, 2021
	Carrying Amount	Level 1	Level 2	Level 3	Total Fair Value
Financial assets					
Fair value through net income					
Risk management contract assets - current					
Foreign exchange contracts	$ 1.2	$ —	$ 1.2	$ —	$ 1.2
	$ 1.2	$ —	$ 1.2	$ —	$ 1.2
Financial liabilities					
Fair value through net income					
Risk management contract liabilities - current					
Commodity contracts	$ 0.5	$ —	$ 0.5	$ —	$ 0.5
Amortized cost					
Current portion of long-term debt[(a)]	1.0	$ —	1.0	$ —	1.0
Long-term debt[(a)]	776.4	—	830.6	—	830.6
	$ 777.9	$ —	$ 832.1	$ —	$ 832.1

(a) Excludes deferred financing costs and debt discount.

The following table presents the significant unobservable inputs used in the fair value measurement of Level 3 financial instruments:

June 30, 2022	**Fair Value**	**Valuation Technique**	**Unobservable Input**	**Weighted average price**	**Unit of Measurement**
Commodity contract - physical					
Renewable natural gas	$ 2.8	Discounted cash flow	Renewable natural gas price	31.95	$/GJ

There is uncertainty caused by using unobservable inputs and changes in the unobservable inputs could result in significantly different fair values.

The following table presents the changes in fair value of risk management contract assets and liabilities classified as Level 3 of the fair value hierarchy:

As at	**June 30, 2022**	December 31, 2021
Balance, beginning of period	**$ —**	$ —
Unrealized gain included in regulatory liabilities	**2.8**	—
Balance, end of period	**$ 2.8**	$ —

There were no transfers into or out of Level 3 as at June 30, 2022 or December 31, 2021.

Risks Associated with Financial Instruments

The following is an update to the Company's risks associated with financial instruments from those disclosed in the Company's 2021 annual audited consolidated financial statements.

Interest Risk

On May 26, 2022, in connection with the Transaction, the Company entered into a deal contingent forward starting interest rate swap in order to hedge a part of the interest rate exposure relating to future long-term debt financing. This derivative has a notional value of US$100 million at a swap rate of 2.77 percent with an effective date of December 30, 2022 to December 30, 2032. The forward starting interest rate swap is contingent on closing of the Transaction by May 25, 2023.

Commodity Price Risk

The Company from time to time may enter into natural gas financial swaps to reduce the customers' exposure to natural gas price volatility. As at June 30, 2022, the Company had outstanding natural gas swaps with notional volumes of approximately 1.5 million MMBtu that are expected to settle within one year. As at December 31, 2021, the Company had outstanding natural gas swaps with notional volumes of 495,000 MMBtu.

In addition, the Company has a biomethane purchase agreement which allows PNG to purchase renewable natural gas from a biogas production and purification facility up to a maximum of 230,000 GJ per annum for 15 years from the in-service date of the facility. Any unrealized gains and losses arising from changes in fair value of this agreement are deferred as a regulatory asset or liability.

Foreign Exchange Risk

A vast majority of HGL's natural gas supply costs are denominated in U.S. dollars. Although all natural gas procurement costs, including any realized foreign exchange gains or losses are passed through to its customers, the Company has entered into foreign exchange forward contracts to manage the risk of fluctuations in gas costs for customers as a result of changes in foreign exchange rates. As at June 30, 2022, the Company had outstanding foreign exchange forward contracts for US$4.5 million at an average rate of $1.25 Canadian per U.S. dollar. These foreign exchange forward contracts have a duration of less than one year. As at December 31, 2021, the Company had outstanding foreign exchange forward contracts for US$36.7 million at an average rate of $1.23 Canadian per U.S. dollar.

11. 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.

The net pension expense by plan for the period was as follows:

Three months ended June 30, 2022	**Defined Benefit**	**Post-Retirement Benefits**	**Total**
Current service cost[a]	**$ 2.0**	**$ 0.2**	**$ 2.2**
Interest cost[b]	**1.1**	**0.1**	**1.2**
Expected return on plan assets[b]	**(1.8)**	**(0.1)**	**(1.9)**
Amortization of regulatory asset[b]	**0.2**	**—**	**0.2**
Net benefit cost recognized	**$ 1.5**	**$ 0.2**	**$ 1.7**

(a) Recorded under the line item "Operating and administrative" expenses on the Condensed Consolidated Statements of Income.
(b) *Recorded under the line item "Other income (loss)" on the Condensed Consolidated Statements of Income.*

Six months ended June 30, 2022	**Defined Benefit**	**Post-Retirement Benefits**	**Total**
Current service cost [a]	**$ 4.0**	**$ 0.4**	**$ 4.4**
Interest cost [b]	**2.2**	**0.2**	**2.4**
Expected return on plan assets [b]	**(3.6)**	**(0.2)**	**(3.8)**
Amortization of regulatory asset [b]	**0.4**	**—**	**0.4**
Net benefit cost recognized	**$ 3.0**	**$ 0.4**	**$ 3.4**

(a) Recorded under the line item "Operating and administrative" expenses on the Condensed Consolidated Statements of Income.
(b) *Recorded under the line item "Other income (loss)" on the Condensed Consolidated Statements of Income.*

Three months ended June 30, 2021	Defined Benefit	Post-Retirement Benefits	Total
Current service cost[a]	$ 2.2	$ 0.2	$ 2.4
Interest cost[b]	0.9	0.1	1.0
Expected return on plan assets[b]	(1.5)	(0.1)	(1.6)
Amortization of regulatory asset[b]	0.6	—	0.6
Net benefit cost recognized	$ 2.2	$ 0.2	$ 2.4

(a) Recorded under the line item "Operating and administrative" expenses on the Condensed Consolidated Statements of Income.
(b) Recorded under the line item "Other income (loss)" on the Condensed Consolidated Statements of Income.

Six months ended June 30, 2021		Defined Benefit		Post-Retirement Benefits		Total
Current service cost [(a)]	$	4.4	$	0.4	$	4.8
Interest cost [(b)]		1.8		0.2		2.0
Expected return on plan assets [(b)]		(3.0)		(0.2)		(3.2)
Amortization of regulatory asset [(b)]		1.2		—		1.2
Net benefit cost recognized	$	4.4	$	0.4	$	4.8

(a) Recorded under the line item "Operating and administrative" expenses on the Condensed Consolidated Statements of Income.
(b) Recorded under the line item "Other income (loss)" on the Condensed Consolidated Statements of Income.

12. COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

The Company has long-term natural gas purchase and transportation arrangements, service agreements, and operating and finance leases, all of which are transacted at market prices and in the normal course of business. Other than as disclosed under note 5, there were no material changes in commitments from those disclosed in the Company's 2021 annual audited consolidated financial statements.

Guarantees

The Company has guaranteed payment for certain commitments on behalf of its subsidiaries as further described below. The primary obligations guaranteed by the Company have been included in the Company's balance sheet and commitments note.

In October 2014, HGL entered into a throughput service contract with Enbridge Inc. for the use of the expansion of its Algonquin Gas Transmission and Maritimes & Northeast Pipeline systems (the "Atlantic Bridge Project"). The contract commenced on October 1, 2020 and will expire 15 years thereafter. The Company issued two guarantees with an aggregate maximum liability of US$91.7 million, guaranteeing HGL's payment obligations under the throughput service contract with Enbridge Inc.

The Company, through HGL, has other agreements in place with natural gas distributors, wholesale gas marketers and financial institutions for the purchase and transportation of natural gas and by-products thereof including forward or other financial settled contracts. As at June 30, 2022, the Company had guarantees with an aggregate maximum of US$60.0 million and $3.3 million guaranteeing HGL's payment under those agreements.

On October 22, 2018, the Company issued a guarantee with a maximum liability of $0.3 million related to the land tenure and the right of way for permanent access and power line access at Bear Mountain Wind Park.

Contingencies

The Company is 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 Company does not believe that the resolution of such claims and actions will have a material impact on the Company's consolidated financial position or results of operations.

13. SUPPLEMENTAL CASH FLOW INFORMATION

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

	Three months ended June 30 2022	Three months ended June 30 2021	Six months ended June 30 2022	Six months ended June 30 2021
Source (use) of cash:				
Accounts receivable	**$ 38.3**	$ 34.8	**$ 35.6**	$ 32.4
Inventory	**(2.9)**	(1.3)	**(0.9)**	(0.6)
Other current assets	**0.1**	0.4	**0.3**	(0.9)
Regulatory assets (current)	**(5.9)**	0.3	**(5.9)**	(0.3)
Accounts payable and accrued liabilities	**(24.1)**	(19.4)	**(20.6)**	(17.6)
Customer deposits	**(0.8)**	(0.3)	**(2.3)**	(3.0)
Regulatory liabilities (current)	**(0.2)**	—	**0.8**	0.8
Other current liabilities	**0.3**	0.3	**(0.6)**	(0.6)
Net change in regulatory assets and liabilities (long-term)[a]	**0.7**	0.4	**3.5**	7.4
Other long-term assets	**0.1**	0.1	**0.1**	0.2
Changes in operating assets and liabilities	**$ 5.6**	$ 15.3	**$ 10.0**	$ 17.8

(a) Inclusive of an increase in the revenue deficiency account (use of cash) of $1.9 million during the three months ended June 30, 2022 and a decrease in the revenue deficiency account (source of cash) of $3.8 million during the six months ended June 30, 2022 (three and six months ended June 30, 2021 – an increase in the revenue deficiency account (use of cash) of $2.2 million and a decrease in the revenue deficiency account (source of cash) of $3.2 million).

The following cash payments have been included in the determination of net income after taxes:

	Three months ended June 30 2022	Three months ended June 30 2021	Six months ended June 30 2022	Six months ended June 30 2021
Interest paid	**$ 13.0**	$ 13.3	**$ 14.1**	$ 14.2
Income taxes paid (net of refunds)	**$ 1.3**	$ —	**$ 1.4**	$ —

14. SEGMENTED INFORMATION

The following describes the Company's three reporting segments:

Renewable Energy	– Includes the 102 MW Bear Mountain Wind Park, and an approximately 10 percent indirect equity investment in Coast LP, which indirectly owns and operates three run-of-river hydroelectric power generation assets in northwest British Columbia.
Utilities	– Includes the rate-regulated natural gas distribution assets in Alberta, British Columbia and Nova Scotia as well as an approximately 33.33 percent equity investment in Inuvik Gas Ltd.
Corporate	– Includes the cost of providing shared services, financial and general corporate support, corporate assets as well as the equity investment in the NGIF Cleantech Ventures Limited Partnership.

The following tables show the composition by segment:

	Three months ended June 30, 2022				
	Utilities	**Renewable Energy**	**Corporate**	**Intersegment Elimination**	**Total**
Revenue	**$ 82.0**	**$ 2.8**	**$ —**	**$ —**	**$ 84.8**
Cost of sales	**(36.7)**	**—**	**—**	**—**	**(36.7)**
Operating and administrative	**(26.2)**	**(1.2)**	**(5.9)**	**—**	**(33.3)**
Accretion expense	**—**	**(0.1)**	**—**	**—**	**(0.1)**
Depreciation and amortization	**(9.6)**	**(1.8)**	**(0.1)**	**—**	**(11.5)**
Income (loss) from equity investments	**—**	**1.6**	**(0.1)**	**—**	**1.5**
Unrealized gain on risk management contracts	**0.4**	**—**	**0.5**	**—**	**0.9**
Other income	**0.6**	**—**	**—**	**—**	**0.6**
Operating income (loss)	**$ 10.5**	**$ 1.3**	**$ (5.6)**	**$ —**	**$ 6.2**
Interest expense	**(2.0)**	**—**	**(5.5)**	**—**	**(7.5)**
Income (loss) before income taxes	**$ 8.5**	**$ 1.3**	**$ (11.1)**	**$ —**	**$ (1.3)**
Net additions (reductions) to:					
Property, plant and equipment[(a)]	**$ 25.5**	**$ —**	**$ 0.1**	**$ —**	**$ 25.6**
Intangible assets	**$ 0.4**	**$ —**	**$ —**	**$ —**	**$ 0.4**

(a) Net additions to property, plant, and equipment, and intangible assets may not agree to changes reflected in the Condensed Consolidated Statement of Cash Flows due to classification differences.

	Six months ended June 30, 2022				
	Utilities	**Renewable Energy**	**Corporate**	**Intersegment Elimination**	**Total**
Revenue	**$ 239.1**	**$ 9.0**	**$ —**	**$ —**	**$ 248.1**
Cost of sales	**(126.3)**	**(0.2)**	**—**	**—**	**(126.5)**
Operating and administrative	**(52.0)**	**(2.6)**	**(8.4)**	**—**	**(63.0)**
Accretion expense	**—**	**(0.1)**	**—**	**—**	**(0.1)**
Depreciation and amortization	**(18.1)**	**(3.6)**	**(0.1)**	**—**	**(21.8)**
Income (loss) from equity investments	**0.1**	**0.4**	**(0.1)**	**—**	**0.4**
Unrealized gain (loss) on risk management contracts	**(0.3)**	**—**	**0.5**	**—**	**0.2**
Other income	**1.3**	**—**	**—**	**—**	**1.3**
Operating income (loss)	**$ 43.8**	**$ 2.9**	**$ (8.1)**	**$ —**	**$ 38.6**
Interest expense	**(3.9)**	**—**	**(11.0)**	**—**	**(14.9)**
Income (loss) before income taxes	**$ 39.9**	**$ 2.9**	**$ (19.1)**	**$ —**	**$ 23.7**
Net additions (reductions) to:					
Property, plant and equipment[(a)]	**$ 38.7**	**$ —**	**$ 0.1**	**$ —**	**$ 38.8**
Intangible assets	**$ 0.8**	**$ —**	**$ —**	**$ —**	**$ 0.8**

(a) Net additions to property, plant, and equipment, and intangible assets may not agree to changes reflected in the Condensed Consolidated Statement of Cash Flows due to classification differences.

Three months ended June 30, 2021	Utilities	Renewable Energy	Corporate	Intersegment Elimination	Total
Revenue	$ 64.1	$ 3.8	$ —	$ —	$ 67.9
Cost of sales	(22.4)	(0.1)	—	—	(22.5)
Operating and administrative	(24.9)	(1.2)	(0.9)	—	(27.0)
Depreciation and amortization	(8.2)	(1.8)	(0.1)	—	(10.1)
Income from equity investments	—	2.5	—	—	2.5
Unrealized gain on risk management contracts	0.5	—	—	—	0.5
Other Income	0.1	—	—	—	0.1
Foreign exchange loss	(0.1)	—	—	—	(0.1)
Operating income	$ 9.1	$ 3.2	$ (1.0)	$ —	$ 11.3
Interest expense	(1.4)	—	(5.6)	—	(7.0)
Income (loss) before income taxes	$ 7.7	$ 3.2	$ (6.6)	$ —	$ 4.3
Net additions (reductions) to:					
Property, plant and equipment[(a)]	$ 15.9	$ —	$ —	$ —	$ 15.9
Intangible assets	$ 3.5	$ —	$ 0.1	$ —	$ 3.6

(a) Net additions to property, plant, and equipment, and intangible assets may not agree to changes reflected in the Condensed Consolidated Statements of Cash Flows due to classification differences

Six months ended June 30, 2021	Utilities	Renewable Energy	Corporate	Intersegment Elimination	Total
Revenue	$ 182.2	$ 9.5	$ —	$ —	$ 191.7
Cost of sales	(78.0)	(0.2)	—	—	(78.2)
Operating and administrative	(49.5)	(2.7)	(1.6)	—	(53.8)
Accretion expense	—	(0.1)	—	—	(0.1)
Depreciation and amortization	(15.6)	(3.6)	(0.1)	—	(19.3)
Income from equity investments	0.1	0.9	—	—	1.0
Unrealized gain on risk management contracts	1.3	—	—	—	1.3
Other Income	0.2	—	—	—	0.2
Foreign exchange loss	(0.2)	—	—	—	(0.2)
Operating income (loss)	$ 40.5	$ 3.8	$ (1.7)	$ —	$ 42.6
Interest expense	(2.8)	—	(11.1)	—	(13.9)
Income (loss) before income taxes	$ 37.7	$ 3.8	$ (12.8)	$ —	$ 28.7
Net additions (reductions) to:					
Property, plant and equipment[(a)]	$ 25.1	$ —	$ —	$ —	$ 25.1
Intangible assets	$ 4.8	$ —	$ 0.1	$ —	$ 4.9

(a) Net additions to property, plant, and equipment, and intangible assets may not agree to changes reflected in the Condensed Consolidated Statements of Cash Flows due to classification differences

The following table shows goodwill and total assets by segment:

	Utilities	Renewable Energy	Corporate	Total
As at June 30, 2022				
Goodwill	**$ 119.1**	**$ —**	**$ —**	**$ 119.1**
Segmented assets	**$ 1,506.2**	**$ 314.1**	**$ (74.4)**	**$ 1,745.9**
As at December 31, 2021				
Goodwill	$ 119.1	$ —	$ —	$ 119.1
Segmented assets	$ 1,487.8	$ 310.5	$ (49.6)	$ 1,748.7

15. SEASONALITY

The utility business is highly seasonal with the majority of natural gas deliveries occurring during the winter heating season. Gas sales increase during the winter resulting in stronger first and fourth quarter results and weaker second and third quarter results. In addition, the Company's equity investment in the Northwest Hydro Facilities is impacted by seasonal weather, which create periods of high river flow typically during May through October of any given year, resulting in stronger results during this time period.

16. SUBSEQUENT EVENTS

Subsequent events have been reviewed through July 26, 2022, the date on which these Financial Statements were approved for issue by the Board of Directors. There were no subsequent events requiring disclosure or adjustment to the Financial Statements.