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 November 3, 2021 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 nine months ended September 30, 2021. This MD&A should be read in conjunction with the accompanying condensed interim consolidated financial statements as at and for the three and nine months ended September 30, 2021 (the "Interim Financial Statements"), the Company's audited consolidated financial statements as at and for the year ended December 31, 2020 (the "2020 Annual Financial Statements") and the Company's management's discussion and analysis for the year ended December 31, 2020 (the "2020 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 term "rate base" and "return on equity" are key performance indicators but are not considered to be a non-GAAP measure. 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 3, 2021 (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 2020 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 impact of the COVID-19 pandemic (as defined herein) on TSU's business, including the amortization and recovery of COVID-19 deferral accounts; expectations regarding the PNG Reactivation Project (as defined herein) and the Salvus to Galloway Project (as defined herein); the impact of the termination of the Top Speed Energy (as defined herein) transportation and interconnection agreements and the Company's intention to find replacement purchasers for the spare capacity on the PNG Reactivation Project; the generic cost of capital proceedings announced by the BCUC (as defined herein); the 2023 cost of service proceedings announced by the AUC (as defined herein); the proceedings for the third PBR (as defined herein) term announced by the AUC; expectations regarding planned expenditures and related investments and capital program from 2021 to 2025 and the expected capital spend in 2021, 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; expected payments under the service and maintenance contract for the wind turbines at the Bear Mountain Wind Park; expected payments under the HGL (as defined herein) building lease agreement; 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; 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: 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. On March 31, 2020, pursuant to a plan of arrangement (the "Arrangement"), TSU became 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 Teachers' Retirement Fund Board ("ATRF") indirectly holds a minority economic interest. ATRF's indirect legal ownership interest in TSU was transferred to Alberta Investment Management Corporation ("AIMCo") on February 1, 2021, and ATRF's interest in TSU is now held by AIMCo in its capacity as investment manager for the benefit of ATRF.

The Company owns rate-regulated natural gas distribution and transmission utility businesses through its 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 one-third equity interest in the utility that delivers natural gas to end-users in Inuvik, Northwest Territories.

THIRD QUARTER FINANCIAL HIGHLIGHTS

(Normalized EBITDA, normalized funds from operations, normalized net income, 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 income after taxes was $2.4 million ($0.08 per Common Share) compared to $0.5 million ($0.02 per Common Share) in the third quarter of 2020.
- Normalized net income was $1.7 million ($0.06 per Common Share), compared to $1.0 million ($0.03 per Common Share) in the third quarter of 2020.
- Operating income was $10.4 million, compared to $9.2 million in the third quarter of 2020.
- Normalized EBITDA was $21.5 million, an increase of 4 percent compared to $20.6 million in the third quarter of 2020.
- Cash from operations was $11.1 million compared to cash used in operations of $2.1 million in the third quarter of 2020.
- Normalized funds from operations were $9.4 million ($0.31 per Common Share), an increase of 9 percent compared to $8.6 million ($0.29 per Common Share) in the third quarter of 2020.
- Net debt was $728.3 million as at September 30, 2021, compared to $717.0 million as at December 31, 2020.
- Net debt to total capitalization ratio was 54.2 percent as at September 30, 2021, compared to 54.0 percent as at December 31, 2020.
- Rate base as at September 30, 2021 was $1,033 million inclusive of construction work in progress, compared to $970 million as at September 30, 2020.
- On July 8, 2021, the British Columbia Utilities Commission ("BCUC") approved the certificate of public convenience and necessity ("CPCN") application for the Salvus to Galloway Project.
- On July 16, 2021, TSU amended its $200 million unsecured syndicated revolving credit facility, including extending the maturity date to July 16, 2025.

HIGHLIGHT SUBSEQUENT TO QUARTER END

- On November 3, 2021, the Board of Directors approved a quarterly dividend of $0.2925 per Common Share, payable on or about December 16, 2021.

OVERVIEW OF THE BUSINESS

TSU has three reporting segments:

- Utilities, which owns and operates utility assets that deliver natural gas to end-users in Alberta, British Columbia and Nova Scotia. TSU also owns a one-third equity interest in the utility that delivers natural gas to end-users in Inuvik, Northwest Territories. In aggregate, the Utilities have approximately $1,033 million of rate base as at September 30, 2021 inclusive of construction work in progress and serve approximately 132,000 customers across Canada.
- Renewable Energy, which includes the Bear Mountain Wind Park and an approximately 10 percent indirect interest in the Northwest Hydro Facilities.
- Corporate, which primarily includes the cost of providing shared services, financing and access to capital, and general corporate support.

BUSINESS AND REGULATORY UPDATES

PNG Reactivation Project

On March 5, 2021, PNG submitted an application to the BCUC seeking a CPCN and approval for costs related to system reactivation and recommissioning work necessary to return the existing Western System back to the contracted utilization (the "PNG Reactivation Project"). The submitted capital cost in the CPCN application is $88.5 million which is expected to be incurred over a four-year period between 2021 and 2024. In June 2021, the BCUC established a regulatory timetable for the continued review of the application through additional information requests. On August 10, 2021, the BCUC approved the underlying transportation and interconnection agreements with new customers. On August 20, 2021, PNG submitted its final argument in support of the CPCN application and on October 6, 2021, PNG filed a reply to the intervener's final submission. A BCUC decision on the CPCN application is anticipated before the end of the fourth quarter of 2021.

On September 10, 2021, Port Edward LNG received approval from the British Columbia Oil and Gas Commission for its project. This is a major milestone in the realization of the PNG Reactivation project, with payments under the terms of the transportation and service agreement with Port Edward LNG scheduled to begin in December 2022.

On September 6, 2021, Top Speed Energy Canada Holdings Ltd. ("Top Speed Energy"), a party to certain transportation and interconnection agreements approved by the BCUC on August 10, 2021, initiated the sale of its Skeena LNG and Totem LNG projects including transportation capacity secured with PNG. On September 28, 2021, PNG provided Top Speed Energy with a notice of critical shipper defaults and notices of termination, which terminated the transportation and interconnection agreements. PNG will work to secure replacement agreements with bona fide purchasers of the Top Speed Energy projects and will concurrently assess whether other parties may be interested in the capacity. PNG does not believe that the termination of the Top Speed Energy agreements should impact the regulatory process nor the timing of a BCUC decision on the issuance of a CPCN for the PNG Reactivation Project.

PNG Salvus to Galloway Project

On October 2, 2020, PNG submitted a CPCN application to the BCUC seeking approval 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"), which 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 $84.8 million, the majority of which is expected to be incurred over a three-year period, between 2021 and 2023. On July 8, 2021, the BCUC granted approval of the CPCN for the Salvus to Galloway Project with directives for reporting on a semi-annual basis over the duration of the project.

AUI Generic Cost of Capital ("GCOC") Proceeding

On March 4, 2021, the Alberta Utilities Commission ("AUC") issued a decision approving the extension of the current ROE of 8.5 percent and equity thickness of 39 percent equity on a final basis for 2022. Following the release of the decision, the Utilities Consumer Advocate filed an appeal with the Court of Appeal of Alberta regarding the AUC's decision, and an application to the AUC for a review and variance of the decision. On August 9, 2021, the AUC dismissed the application for a review and variance of the decision. On October 7, 2021, the Court of Appeal of Alberta dismissed the appeal of the AUC's decision filed by the Utilities Consumer Advocate.

PNG GCOC Proceeding

In January 2021, the BCUC issued a notice that it would be initiating a GCOC proceeding in the spring of 2021 to address the appropriate common equity component and return on equity for the utilities it regulates, and that the determinations from this proceeding would apply to rate setting effective January 1, 2022. On May 21, 2021, the BCUC issued an order to establish a two-stage proceeding to set public utilities' cost of capital. On September 24, 2021, the BCUC established that a benchmark utility methodology would be used in the determination of the cost of capital for utilities in British Columbia, and the BCUC also established a further regulatory timetable.

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. The AUC has prescribed the minimum level of detail each application is expected to include to support the utilities' 2023 revenue requirement forecasts but did not prescribe a traditional cost of service methodology for developing the 2023 revenue requirement forecasts. Instead, the AUC will adopt a hybrid methodology for assessing the 2023 forecasts where the extent to which expenditures are examined is guided by the nature, size or complexity of the associated cost to facilitate a streamlined review of the upcoming 2023 cost of service applications. AUI's 2023 cost of service application is due on December 15, 2021.

AUI Evaluation of Performance Based Regulation in Alberta

On June 30, 2021, the AUC issued a decision regarding the performance of the first and second terms (to date) of performance-based regulation ("PBR") of the electric and gas distribution utilities operating in Alberta. The AUC found, on balance, that PBR has achieved many of the objectives that were set out in the founding PBR principles. Although areas for improvement remain, the AUC determined it to be in the public interest that the distribution utilities return to a third PBR term commencing in 2024, upon completion of the 2023 cost of service year. The parameters and changes to be adopted for the third PBR term will be set in a future generic proceeding tentatively set to commence in the third quarter of 2022.

Impact of the COVID-19 Pandemic

The Company is continuing to monitor and adhere to guidance provided by the provincial governments and public health officials related to the novel coronavirus of 2019 ("COVID-19"). The Company continues to prioritize providing safe and reliable services to customers while ensuring the health and safety of its employees and the community. In response to COVID-19, both the AUC and BCUC announced payment deferral programs in 2020.

In March 2020, the Government of Alberta announced a program for Albertans who were experiencing financial hardship directly related to the COVID-19 pandemic. The program allowed customers to defer payments of electricity and natural gas bills from March 18, 2020 until June 18, 2020 without any late fees or added interest payments. In addition, no Albertans could be disconnected from these services or see their services reduced during this period due to non-payment. Albertans who were enrolled in the bill deferral program were required to repay the deferred amount by June 18, 2021. On May 28, 2020, the AUC approved AUI's application to establish deferral accounts for the purposes of administering deferred payments under the *Utility Payment Deferral Program Act* (Alberta). As at June 18, 2021, AUI had approximately $0.4 million outstanding under these deferral accounts, and an application for AUI's Utility Payment Deferral Program rate rider was submitted to the AUC on July 16, 2021. On August 18, 2021, the AUC approved AUI's application for Utility Payment Deferral Program balances to be included within a natural gas rate rider to be collected from all Alberta natural gas customers commencing November 1, 2021.

On June 10, 2020, the BCUC approved PNG's application to offer a bill payment deferral program between April 17, 2020 and June 30, 2020 to residential and small commercial customers that have experienced a loss of income or revenue as a result of the COVID-19 pandemic. The BCUC also granted approval for PNG to establish deferral accounts to capture unplanned costs incurred and cost savings as a result of the COVID-19 pandemic and to capture bad debts that may be incurred specifically as a result of the impact of COVID-19. PNG expects to apply for the amortization of the COVID-19 deferral accounts in future revenue requirement applications. As at September 30, 2021, $1.7 million of net cost savings have been identified and deferred as regulatory liabilities.

The Company is continuing to monitor customer accounts and while the Company has resumed normal collection activities, it is also continuing to work with customers impacted by COVID-19 on payment arrangements. While the COVID-19 pandemic did not significantly impact the carrying value of accounts receivable and the liquidity position of the Company as at September 30, 2021, given the unprecedented and changing developments surrounding the COVID-19 pandemic, it is not possible to reliably estimate the impact of the COVID-19 pandemic on the financial results and condition of the Company in future periods. As at September 30, 2021, the Company has approximately $219.0 million of cash balances and available credit facilities. The Company is continuing to monitor the potential impact of the pandemic on ongoing operations and associated financial implications.

CAPITAL PROGRAM GUIDANCE

Over the 2021 to 2025 time period, TSU expects capital spending of up to $680 million at its 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 2021, TSU now expects capital spending to be in the range of $110 to $120 million. The increase in expected capital spending is mainly due to accelerated spending on the Salvus to Galloway Project, as well as additional capital at PNG to maintain and improve system integrity.

SELECTED FINANCIAL INFORMATION

The following tables summarize key financial results:

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2021**	2020	**2021**	2020
Normalized EBITDA(1)	**21.5**	20.6	**84.1**	81.5
Operating income	**10.4**	9.2	**52.9**	28.1
Net income after taxes	**2.4**	0.5	**30.2**	7.3
Normalized net income(1)	**1.7**	1.0	**28.2**	25.9
Total assets	**1,662.9**	1,584.3	**1,662.9**	1,584.3
Total long-term liabilities	**974.9**	921.9	**974.9**	921.9
Net additions to property, plant and equipment	**30.5**	22.6	**55.6**	40.4
Dividends declared	**8.3**	7.8	**24.8**	23.4
Cash from (used in) operations	**11.1**	(2.1)	**74.7**	41.7
Normalized funds from operations(1)	**9.4**	8.6	**55.3**	52.8

	Three Months Ended September 30		Nine Months Ended September 30	
($ per Common Share, except Common Shares outstanding)	**2021**	2020	**2021**	2020
Net income after taxes - basic	**0.08**	0.02	**1.01**	0.24
Net income after taxes - diluted	**0.08**	0.02	**1.01**	0.24
Normalized net income - basic(1)	**0.06**	0.03	**0.94**	0.86
Dividends declared	**0.2750**	0.2600	**0.8250**	0.7800
Cash from (used in) operations	**0.37**	(0.07)	**2.49**	1.39
Normalized funds from operations(1)	**0.31**	0.29	**1.84**	1.76
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 September 30		Nine Months Ended September 30	
($ millions)	**2021**	2020	**2021**	2020
Revenue	**54.6**	48.6	**246.3**	223.0
Cost of sales	**(13.4)**	(9.6)	**(91.6)**	(74.3)
Operating and administrative expense	**(25.3)**	(24.3)	**(79.2)**	(97.2)
Accretion expense	**(0.1)**	—	**(0.2)**	(0.1)
Depreciation and amortization expense	**(10.7)**	(9.9)	**(30.0)**	(27.8)
Income from equity investments	**4.6**	4.7	**5.6**	4.0
Unrealized gain (loss) on foreign exchange contracts	**0.7**	(0.4)	**2.0**	—
Other income	**0.1**	0.2	**0.3**	0.6
Foreign exchange loss	**(0.1)**	(0.1)	**(0.3)**	(0.1)
Operating income	**10.4**	9.2	**52.9**	28.1
Interest expense	**(7.1)**	(7.3)	**(20.9)**	(21.3)
Income tax recovery (expense)	**(0.9)**	(1.4)	**(1.8)**	0.5
Net income after taxes	**2.4**	0.5	**30.2**	7.3

Three Months Ended September 30

Normalized EBITDA for the three months ended September 30, 2021 was $21.5 million, an increase of $0.9 million relative to the same period in 2020 primarily due to higher approved rates and rate base growth at the Utilities and higher revenues at the Bear Mountain Wind Park, partially offset by higher operating and administrative expense.

Operating income for the three months ended September 30, 2021 was $10.4 million, an increase of $1.2 million relative to the same period in 2020 primarily due to the increase in normalized EBITDA discussed above and an unrealized gain on foreign exchange contracts compared to a loss in the same period in 2020, partially offset by higher depreciation and amortization expense.

Operating and administrative expense for the three months ended September 30, 2021 was $25.3 million, an increase of $1.0 million from the same period in 2020 mainly due to inflationary salary and wage increases and higher maintenance costs at the Bear Mountain Wind Park.

Depreciation and amortization expense for the three months ended September 30, 2021 was $10.7 million, an increase of $0.8 million from the same period in 2020 mainly due to a higher PP&E balance.

Interest expense for the three months ended September 30, 2021 was $7.1 million compared to $7.3 million in the same period in 2020. The decrease of $0.2 million was mainly due to a lower average interest rate, partially offset by a higher average debt balance outstanding.

Income tax expense for the three months ended September 30, 2021 was $0.9 million, compared to $1.4 million in the same period in 2020. The decrease in income tax expense was primarily due to lower taxable income as a result of higher capital cost allowance deductions.

Normalized net income for the three months ended September 30, 2021 was $1.7 million, an increase of $0.7 million relative to the same period in 2020 mainly due to the same factors as the increase in normalized EBITDA discussed above, lower income tax expense and lower interest expense, partially offset by higher depreciation and amortization expense.

Net income after taxes for the three months ended September 30, 2021 was $2.4 million, an increase of $1.9 million compared to the same period in 2020. The increase was due to the same factors as the increase in operating income discussed above, lower income tax expense and lower interest expense.

Normalized funds from operations for the three months ended September 30, 2021 was $9.4 million, an increase of $0.8 million relative to the same period in 2020 primarily due to higher approved rates and rate base growth at the Utilities, higher revenues at the Bear Mountain Wind Park, higher distributions from the investment in the Northwest Hydro Facilities, and lower interest expense, partially offset by higher operating and administrative expense and higher 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 operations.

Nine Months Ended September 30

Normalized EBITDA for the nine months ended September 30, 2021 was $84.1 million, an increase of $2.6 million relative to the same period in 2020 primarily due to higher approved rates and rate base growth at the Utilities, higher normalized EBITDA from the Northwest Hydro Facilities, and higher revenues at the Bear Mountain Wind Park, partially offset by higher operating and administrative expense and warmer weather compared to the same period in 2020 in Nova Scotia and Alberta.

Operating income for the nine months ended September 30, 2021 was $52.9 million, an increase of $24.8 million relative to the same period in 2020 primarily due to the absence of pre-tax transaction costs of approximately $22.6 million incurred in respect of the Arrangement in 2020, higher unrealized gains on foreign exchange contracts and the same factors as the increase in normalized EBITDA discussed above, partially offset by higher depreciation and amortization expense.

Operating and administrative expense for the nine months ended September 30, 2021 was $79.2 million, a decrease of $18.0 million from the same period in 2020 primarily due to the absence of transaction costs of $22.6 million incurred in respect of the Arrangement, partially offset by inflationary salary and wage increases, higher pension and consulting expenses, and higher maintenance costs at the Bear Mountain Wind Park.

Depreciation and amortization expense for the nine months ended September 30, 2021 was $30.0 million, an increase of $2.2 million from the same period in 2020 primarily due to a higher PP&E balance.

Interest expense for the nine months ended September 30, 2021 was $20.9 million, compared to $21.3 million in the same period in 2020. The decrease of $0.4 million was primarily due to a lower average interest rate, partially offset by a higher average debt balance outstanding.

Income tax expense for the nine months ended September 30, 2021 was $1.8 million, compared to income tax recovery of $0.5 million in the same period in 2020. The increase in income tax expense was primarily due to higher taxable income as a result of the absence of transaction costs incurred in respect of the Arrangement in 2020, partially offset by lower taxes due to higher capital cost allowances. Removing the tax impact of the transaction costs incurred in respect of the Arrangement, income tax expense for the nine months ended September 30, 2020 was $3.5 million.

Normalized net income for the nine months ended September 30, 2021 was $28.2 million, an increase of $2.3 million relative to the same period in 2020 primarily due to the increase in normalized EBITDA discussed above, lower normalized income tax expense, and lower interest expense, partially offset by higher depreciation and amortization expense.

Net income after taxes for the nine months ended September 30, 2021 was $30.2 million, an increase of $22.9 million compared to the same period in 2020. The increase was due to the same factors as the increase in operating income discussed above and lower interest expense, partially offset by higher income tax expense.

Normalized funds from operations for the nine months ended September 30, 2021 was $55.3 million, an increase of $2.5 million relative to the same period in 2020 primarily due to rate base growth and higher approved rates at the Utilities, higher distributions from the investment in the Northwest Hydro Facilities, higher revenues at the Bear Mountain Wind Park, lower current income tax expense, and lower interest expense, partially offset by warmer weather compared to last year in Nova Scotia and Alberta and higher operating and administrative expense.

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

RESULTS BY REPORTING SEGMENT

Normalized EBITDA by Reporting Segment(1)

($ millions)	Three Months Ended September 30 **2021**	Three Months Ended September 30 2020	Nine Months Ended September 30 **2021**	Nine Months Ended September 30 2020
Utilities	**$ 13.4**	$ 12.4	**$ 68.2**	$ 66.7
Renewable Energy	**8.8**	8.6	**18.2**	16.0
Corporate	**(0.7)**	(0.4)	**(2.3)**	(1.2)
	$ 21.5	$ 20.6	**$ 84.1**	$ 81.5

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

Operating Income (Loss) by Reporting Segment

($ millions)	Three Months Ended September 30 **2021**	Three Months Ended September 30 2020	Nine Months Ended September 30 **2021**	Nine Months Ended September 30 2020
Utilities	**$ 5.1**	$ 3.8	**$ 45.4**	$ 44.3
Renewable Energy	**6.0**	5.9	**9.9**	7.7
Corporate	**(0.7)**	(0.5)	**(2.4)**	(23.9)
	$ 10.4	$ 9.2	**$ 52.9**	$ 28.1

UTILITIES SEGMENT REVIEW

Financial results

($ millions)	Three Months Ended September 30 2021	Three Months Ended September 30 2020	Nine Months Ended September 30 2021	Nine Months Ended September 30 2020
Revenue	**$ 50.0**	$ 44.5	**$ 232.2**	$ 210.1
Cost of sales	**(13.3)**	(9.5)	**(91.4)**	(74.1)
Operating and administrative expense	**(23.3)**	(22.8)	**(72.9)**	(69.9)
Normalized EBITDA from equity investment	**(0.1)**	—	**—**	—
Other income	**0.1**	0.2	**0.3**	0.6
Normalized EBITDA[1]	**$ 13.4**	$ 12.4	**$ 68.2**	$ 66.7
Unrealized gain (loss) on foreign exchange contracts	**0.7**	(0.4)	**2.0**	—
Depreciation and amortization expense	**(8.9)**	(8.1)	**(24.4)**	(22.3)
Foreign exchange loss	**(0.1)**	(0.1)	**(0.3)**	(0.1)
Accretion expense	**—**	—	**(0.1)**	—
Operating income	**$ 5.1**	$ 3.8	**$ 45.4**	$ 44.3

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

Operating statistics

	Three Months Ended September 30 2021	Three Months Ended September 30 2020	Nine Months Ended September 30 2021	Nine Months Ended September 30 2020
Natural gas deliveries - end-use (PJ)	**2.9**	3.0	**21.7**	22.7
Natural gas deliveries - transportation (PJ)	**1.1**	1.1	**3.9**	3.9
Degree day variance from normal - AUI (%)[1]	**(31.4)**	(19.0)	**(4.1)**	6.9
Degree day variance from normal - HGL (%)[1]	**(31.7)**	8.9	**(10.2)**	(3.2)

(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 September 30

Revenue increased by $5.5 million for the three months ended September 30, 2021 compared to the same period in 2020 primarily due to higher approved rates and rate base growth, partially offset by warmer weather compared to the same period in 2020 in Nova Scotia and Alberta.

Normalized EBITDA increased by $1.0 million for the three months ended September 30, 2021 compared to the same period in 2020 primarily due to higher approved rates and rate base growth, partially offset by warmer weather compared to the same period in 2020 in Nova Scotia and Alberta.

Operating income increased by $1.3 million for the three months ended September 30, 2021 compared to the same period in 2020 primarily due to the same factors as the increase in normalized EBITDA discussed above and an unrealized gain on foreign exchange contracts compared to a loss in the same period in 2020, partially offset by higher depreciation and amortization expense.

Nine Months Ended September 30

Revenue increased by $22.1 million for the nine months ended September 30, 2021 compared to the same period in 2020 primarily due to higher approved rates and rate base growth, partially offset by warmer weather compared to the same period in 2020 in Nova Scotia and Alberta.

Normalized EBITDA increased by $1.5 million for the nine months ended September 30, 2021 compared to the same period in 2020 primarily due to higher approved rates and rate base growth, partially offset by warmer weather compared to the same period in 2020 in Nova Scotia and Alberta and higher salary, pension and consulting expense.

Operating income increased by $1.1 million for the nine months ended September 30, 2021 compared to the same period in 2020 primarily due to the same factors as the increase in normalized EBITDA discussed above and higher unrealized gain on foreign exchange contracts, partially offset by higher depreciation and amortization expense.

RENEWABLE ENERGY SEGMENT REVIEW

Financial results

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2021**	2020	**2021**	2020
Revenue	**$ 4.6**	$ 4.1	**$ 14.1**	$ 12.9
Cost of sales	**(0.1)**	(0.1)	**(0.2)**	(0.2)
Operating and administrative expense	**(1.3)**	(1.0)	**(4.0)**	(3.5)
Normalized EBITDA from equity investment	**5.6**	5.6	**8.3**	6.8
Normalized EBITDA[(1)]	**$ 8.8**	$ 8.6	**$ 18.2**	$ 16.0
Depreciation and amortization expense	**(1.8)**	(1.8)	**(5.5)**	(5.4)
Accretion expense	**(0.1)**	—	**(0.1)**	(0.1)
Accretion and depreciation and amortization expense from equity investment	**(0.9)**	(0.9)	**(2.7)**	(2.8)
Operating income	**$ 6.0**	$ 5.9	**$ 9.9**	$ 7.7

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

Operating statistics

	Three Months Ended September 30		Nine Months Ended September 30	
	2021	2020	**2021**	2020
Bear Mountain Wind Park power sold (GWh)	**45.2**	43.6	**134.4**	137.0
Northwest Hydro Facilities power sold (GWh)[(1)]	**56.0**	48.5	**97.1**	73.8

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

Three Months Ended September 30

Revenue increased by $0.5 million for the three months ended September 30, 2021 compared to the same period in 2020 primarily due to higher revenue from the sales of renewable energy certificates ("RECs") and higher generation from the Bear Mountain Wind Park.

Normalized EBITDA increased by $0.2 million for the three months ended September 30, 2021 compared to the same period in 2020 primarily due to higher sales of RECs and higher generation at the Bear Mountain Wind Park, partially offset by higher maintenance costs.

Operating income increased by $0.1 million for the three months ended September 30, 2021 compared to the same period in 2020 mainly due to the same factors as the increase in normalized EBITDA discussed above.

During the three months ended September 30, 2021, TSU recorded $4.7 million of equity income from its investment in the Northwest Hydro Facilities, consistent with the same period in 2020.

Nine Months Ended September 30

Revenue increased by $1.2 million for the nine months ended September 30, 2021 compared to the same period in 2020 primarily due to higher revenue from the sales of RECs, partially offset by lower generation at the Bear Mountain Wind Park.

Normalized EBITDA increased by $2.2 million for the nine months ended September 30, 2021 compared to the same period in 2020 primarily due to higher normalized EBITDA from the Northwest Hydro Facilities and higher sales of RECs at the Bear Mountain Wind Park, partially offset by lower generation at the Bear Mountain Wind Park and higher maintenance costs.

Operating income increased by $2.2 million for the nine months ended September 30, 2021 compared to the same period in 2020 due to the same factors as the increase in normalized EBITDA discussed above.

During the nine months ended September 30, 2021, TSU recorded $5.6 million of equity income from its investment in the Northwest Hydro Facilities, compared to $4.0 million of equity income from its investment in the same period in 2020. The increase in equity income was primarily due to the curtailment of purchases by BC Hydro in 2020.

CORPORATE SEGMENT REVIEW

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2021**	2020	**2021**	2020
Operating and administrative expense	**$ (0.7)**	$ (0.4)	**$ (2.3)**	$ (1.2)
Normalized EBITDA[1]	**$ (0.7)**	$ (0.4)	**$ (2.3)**	$ (1.2)
Depreciation and amortization	**—**	—	**(0.1)**	(0.1)
Transaction costs	**—**	(0.1)	**—**	(22.6)
Operating loss	**$ (0.7)**	$ (0.5)	**$ (2.4)**	$ (23.9)

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

For the three and nine months ended September 30, 2021, normalized EBITDA was a loss of $0.7 and $2.3 million, respectively (2020 - $0.4 million and $1.2 million, respectively). The decrease in normalized EBITDA for the three and nine months ended September 30, 2021 compared to the same periods in 2020 was primarily due to higher salaries and wages. For the three and nine months ended September 30, 2021, expenses incurred by the Corporate segment were associated with providing corporate shared services and business development.

For the three and nine months ended September 30, 2021, corporate costs of $1.7 million and $5.0 million, respectively, were allocated to TSU's operating segments, compared to $1.6 million and $5.3 million, respectively, for the same periods in 2020.

For the three and nine months ended September 30, 2021, operating loss was $0.7 million and $2.4 million, respectively (2020 - $0.5 million and $23.9 million, respectively). The increase in operating loss for the three months ended September 30, 2021 compared to the same period in 2020 was primarily due to higher salaries and wages. The decrease in operating loss for nine months ended September 30, 2021 compared to the same period in 2020 was primarily due to the absence of transaction costs of approximately $22.6 million incurred during the nine months ended September 30, 2020 in respect of the Arrangement, partially offset by higher salaries and wages.

SUMMARY OF SELECTED QUARTERLY RESULTS[1]

The following table sets forth unaudited quarterly information for each of the eight quarters from the quarter ended December 31, 2019 to the quarter ended September 30, 2021.

($ millions, except per Common Share amounts)	**Q3-21**	Q2-21	Q1-21	Q4-20
Revenue	**54.6**	67.9	123.9	99.8
Normalized net income[2]	**1.7**	3.5	23.1	17.4
Net income after taxes	**2.4**	4.0	23.9	15.5
Net income after taxes per Common Share - basic ($)	**0.08**	0.13	0.80	0.52
Net income after taxes per Common Share - diluted ($)	**0.08**	0.13	0.80	0.52
Dividends declared per Common Share ($)	**0.2750**	0.2750	0.2750	0.2750

($ millions, except per Common Share amounts)	Q3-20	Q2-20	Q1-20	Q4-19
Revenue	48.6	61.3	113.0	101.2
Normalized net income[2]	1.0	1.8	22.9	18.6
Net income after taxes	0.5	0.3	6.5	16.1
Net income after taxes per Common Share - basic ($)	0.02	0.01	0.22	0.54
Net income after taxes per Common Share - diluted ($)	0.02	0.01	0.22	0.53
Dividends declared per Common Share ($)	0.2600	0.2600	0.2600	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.

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

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. Net income after taxes during the periods noted was impacted by after-tax transaction costs of approximately $1.8 million incurred in the fourth quarter of 2019, approximately $18.0 million incurred in the first quarter of 2020 and approximately $0.4 million incurred in the second quarter of 2020 in respect of the Arrangement.

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 September 30		Nine Months Ended September 30	
($ millions)	**2021**	2020	**2021**	2020
Cash from (used in) operations	**$ 11.1**	$ (2.1)	**74.7**	41.7
Cash used in investing activities	**(27.2)**	(22.4)	**(60.5)**	(50.2)
Cash from (used in) financing activities	**14.7**	(5.0)	**(19.5)**	15.7
Increase (decrease) in cash and cash equivalents	**$ (1.4)**	$ (29.5)	**(5.3)**	7.2

Cash from operations

During the three and nine months ended September 30, 2021, cash from operations increased by $13.2 million and $33.0 million, respectively, as compared to the same periods in 2020 primarily due to higher cash earnings, a favourable variance from changes in operating assets and liabilities, and higher distributions from the investment in the Northwest Hydro Facilities. The favourable variance in changes in operating assets and liabilities were mainly due to timing of supplier payments.

Investing activities

During the three and nine months ended September 30, 2021, cash used in investing activities increased by $4.8 million and $10.3 million, respectively, as compared to the same periods in 2020 primarily due to higher capital expenditures.

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

Financing activities

During the three months ended September 30, 2021, cash from financing activities increased by $19.7 million as compared to the same period in 2020 primarily due to higher net debt issuance, partially offset by an increase in dividends paid.

During the nine months ended September 30, 2021, cash used in financing activities increased by $35.2 million as compared to the same period in 2020 primarily due to lower net debt issuance and an increase in dividends paid.

Working Capital

($ millions except current ratio)		September 30, 2021		December 31, 2020
Current assets	$	48.4	$	82.5
Current liabilities		73.0		88.5
Working capital (deficiency)	$	(24.6)	$	(6.0)
Working capital ratio		0.66		0.93

The variation in the working capital ratio was primarily due to a decrease in accounts receivable and a decrease in cash held, partially offset by a decrease in accounts payable and accrued liabilities and short-term debt. 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)		September 30, 2021	December 31, 2020
Short-term debt	$	0.8	4.1
Current portion of long-term debt		1.0	1.0
Long-term debt[1]		728.3	719.0
Total debt		730.1	724.1
Less: cash and cash equivalents		(1.8)	(7.1)
Net debt[2]	$	728.3	717.0
Shareholder's equity		615.0	609.6
Total capitalization	$	1,343.3	1,326.6
Net debt-to-total capitalization[2] (%)		54.2	54.0

(1) Net of debt issuance costs of $3.1 million as of September 30, 2021 (December 31, 2020 - $3.4 million).

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

As at September 30, 2021, TSU's total debt primarily consisted of outstanding MTNs of $650 million (December 31, 2020 - $650 million), PNG debentures of $23.5 million (December 31, 2020 - $24.0 million), and $59.3 million drawn under other bank credit facilities (December 31, 2020 - $53.1 million). In addition, TSU had $8.5 million of letters of credit issued (December 31, 2020 - $8.5 million).

TSU's earnings interest coverage for the rolling 12 months ended September 30, 2021 was 2.7 times (12 months ended September 30, 2020 – 1.9 times).

Credit Facilities

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

($ millions)	Borrowing capacity	Drawn at September 30, 2021	Drawn at December 31, 2020
Syndicated revolving credit facility(1)	$ **200.0**	$ **33.5**	$ 24.0
Operating credit facility(2)	**35.0**	**3.4**	3.8
PNG committed credit facility(3)	**25.0**	**25.0**	25.0
PNG operating credit facility(4)	**25.0**	**5.9**	8.8
	$ **285.0**	$ **67.8**	$ 61.6

(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 September 30, 2021, a total of $3.4 million (December 31, 2020 - $3.8 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 September 30, 2021, $5.1 million (December 31, 2020 - $4.7 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 September 30, 2021
Bank debt-to-capitalization(1)(2)	not greater than 65 percent	**54.1%**

(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 September 30, 2021, $1.0 billion was available under the base shelf prospectus.

CAPITAL EXPENDITURES

($ millions)	Three Months Ended September 30, 2021				Three Months Ended September 30, 2020			
	Renewable Energy	**Utilities**	**Corporate**	**Total**	Renewable Energy	Utilities	Corporate	Total
Capital expenditures:								
PP&E	**$ —**	**$ 30.6**	**$ —**	**$ 30.6**	$ 0.1	$ 23.4	$ —	$ 23.5
Intangible assets	**—**	**3.6**	**—**	**3.6**	—	2.8	—	2.8
Capital expenditures	**—**	**34.2**	**—**	**34.2**	0.1	26.2	—	26.3
Disposals:								
PP&E	**—**	**(0.1)**	**—**	**(0.1)**	—	(0.9)	—	(0.9)
Net capital expenditures	**$ —**	**$ 34.1**	**$ —**	**$ 34.1**	$ 0.1	$ 25.3	$ —	$ 25.4

($ millions)	Nine Months Ended September 30, 2021				Nine Months Ended September 30, 2020			
	Renewable Energy	**Utilities**	**Corporate**	**Total**	Renewable Energy	Utilities	Corporate	Total
Capital expenditures:								
PP&E	**$ —**	**$ 55.8**	**$ —**	**$ 55.8**	$ 0.2	$ 42.1	$ —	$ 42.3
Intangible assets	**—**	**8.4**	**0.1**	**8.5**	—	7.5	—	7.5
Capital expenditures	**—**	**64.2**	**0.1**	**64.3**	0.2	49.6	—	49.8
Disposals:								
PP&E	**—**	**(0.2)**	**—**	**(0.2)**	—	(1.9)	—	(1.9)
Net capital expenditures	**$ —**	**$ 64.0**	**$ 0.1**	**$ 64.1**	$ 0.2	$ 47.7	$ —	$ 47.9

Capital expenditures for the three and nine months ended September 30, 2021 were $34.2 million and $64.3 million, respectively, compared to $26.3 million and $49.8 million during the three and nine months ended September 30, 2020. The increase in capital expenditures was mainly due to higher capital expenditures related to system betterment, replacement of transmission and distribution lines, and new business installations as well as expenditures incurred on the Salvus to Galloway Project in 2021. Of the total capital expenditures, approximately $9.5 million and $12.0 million were incurred on the Salvus to Galloway Project and approximately $3.6 million and $8.5 million were incurred on software development costs during the three and nine months ended September 30, 2021, respectively.

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. Other than as discussed under the "*Business and Regulatory Updates – Impact of the COVID-19 Pandemic*" section of this MD&A, there have been no significant changes during the nine months ended September 30, 2021 to the Company's business risks that were disclosed in the 2020 Annual MD&A.

SHARE INFORMATION

	As at November 3, 2021
Issued and outstanding	
Common Shares	30,000,000

ADOPTION OF NEW ACCOUNTING STANDARDS

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

- ASU No. 2019-12 "Income Taxes – Simplifying the Accounting for Income Taxes". The amendments in this ASU removes certain exceptions and provides some simplifications in accounting for income taxes. The adoption of this ASU did not have a material impact on the Company's consolidated financial statements; and

- ASU No. 2020-01 "Investments – Equity Securities (Topic 321), Investments – Equity Method and Joint Ventures (Topic 323) and Derivatives and Hedging (Topic 815) – Clarifying the Interactions between Topic 321, Topic 323, and Topic 815". The amendments in this ASU provides guidance for accounting for certain equity securities when the equity method of accounting is applied or discontinued and for forward contracts and purchased options on certain securities. The adoption of this ASU did not have a material impact on the Company's 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 consolidated financial statements.

OFF-BALANCE SHEET ARRANGEMENTS

During the second quarter of 2021, the Company entered into two guarantees with an aggregate maximum of US$20.0 million in relation to payment obligations associated with HGL's natural gas purchase and transportation contracts. During the third quarter of 2021, HGL entered into a building lease agreement with an initial term of fifteen years after commencement of the lease. The lease will commence upon the completion of the construction of the building. The total lease payments over the lease term are expected to be approximately $7.9 million. In addition, effective October 7, 2021, Bear Mountain Wind Park entered into a five-year service and maintenance contract for the wind turbines commencing on December 7, 2021. The total payments over the term of the contract are expected to be approximately $11.5 million. Other than as noted, TSU did not enter into any material off-balance sheet arrangements during the nine months ended September 30, 2021. Reference should be made to the 2020 Annual Financial Statements and 2020 Annual MD&A.

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, normalized net income 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 September 30		Nine Months Ended September 30	
($ millions)	**2021**	2020	**2021**	2020
Normalized EBITDA	**$ 21.5**	$ 20.6	**$ 84.1**	$ 81.5
Add (deduct):				
Foreign exchange loss	**(0.1)**	(0.1)	**(0.3)**	(0.1)
Unrealized gain (loss) on foreign exchange contracts	**0.7**	(0.4)	**2.0**	—
Accretion expense	**(0.1)**	—	**(0.2)**	(0.1)
Depreciation and amortization expense	**(10.7)**	(9.9)	**(30.0)**	(27.8)
Accretion and depreciation and amortization expense from equity investment	**(0.9)**	(0.9)	**(2.7)**	(2.8)
Transaction costs	**—**	(0.1)	**—**	(22.6)
Operating income	**$ 10.4**	$ 9.2	**$ 52.9**	$ 28.1

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 expenses, foreign exchange gain (loss), unrealized gain (loss) on foreign exchange contracts, and other typically non-recurring items. 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 and Normalized Net Income per Share

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2021**	2020	**2021**	2020
Normalized net income	**$ 1.7**	$ 1.0	**$ 28.2**	$ 25.9
Add (deduct) after-tax:				
Unrealized gain (loss) on foreign exchange contracts	**0.7**	(0.4)	**2.0**	—
Transaction costs	**—**	(0.1)	**—**	(18.6)
Net income after taxes	**$ 2.4**	$ 0.5	**$ 30.2**	$ 7.3

Normalized net income represents net income after taxes adjusted for the after-tax impact of unrealized gain (loss) on foreign exchange contracts and other typically non-recurring items. Normalized net income per share is calculated by dividing normalized net income by the weighted average number of common shares. These measures are presented in order to enhance the comparability of results, as it reflects the underlying performance of the Company.

Normalized net income and normalized net income per share as presented should not be viewed as an alternative to net income 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 September 30 2021	Three Months Ended September 30 2020	Nine Months Ended September 30 2021	Nine Months Ended September 30 2020
Normalized funds from operations	**$ 9.4**	$ 8.6	**$ 55.3**	$ 52.8
Add (deduct):				
Changes in operating assets and liabilities	**1.7**	(10.6)	**19.4**	11.5
Transaction costs	**—**	(0.1)	**—**	(22.6)
Cash from (used in) operations	**$ 11.1**	$ (2.1)	**$ 74.7**	$ 41.7

Normalized funds from operations and normalized funds from operations per share are 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. Management uses these measures 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

GW means gigawatt
GWh means gigawatt hour
PJ means petajoule; one million gigajoules
PP&E means property, plant and equipment

ABOUT TSU

TSU is a Canadian company with natural gas distribution utilities and renewable power generation assets. TSU serves approximately 132,000 customers, delivering low carbon energy, safely and reliably. For more information visit: www.trisummit.ca

Condensed Consolidated Balance Sheets *(unaudited)*

As at *($ millions)*	**September 30, 2021**	December 31, 2020
ASSETS		
Current assets		
Cash and cash equivalents	**$ 1.8**	$ 7.1
Accounts receivable, net of allowances	**32.1**	64.8
Inventory	**4.3**	2.2
Regulatory assets	**5.2**	3.8
Foreign exchange contracts asset *(note 8)*	**0.6**	—
Prepaid expenses and other current assets	**4.4**	4.6
	48.4	82.5
Property, plant and equipment	**1,056.8**	1,028.7
Intangible assets	**39.3**	34.0
Goodwill	**119.1**	119.1
Regulatory assets	**269.2**	257.3
Other long-term assets	**11.3**	12.0
Investments accounted for by the equity method	**118.8**	116.1
	$ 1,662.9	$ 1,649.7
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	**$ 57.2**	$ 62.9
Short-term debt *(note 4)*	**0.8**	4.1
Current portion of long-term debt *(note 5)*	**1.0**	1.0
Customer deposits	**8.8**	10.4
Regulatory liabilities	**3.4**	6.2
Foreign exchange contracts liability *(note 8)*	**0.1**	1.5
Other current liabilities	**1.7**	2.4
	73.0	88.5
Long-term debt *(note 5)*	**728.3**	719.0
Asset retirement obligations	**4.7**	4.5
Deferred income taxes *(note 7)*	**148.9**	140.5
Regulatory liabilities	**39.2**	33.4
Lease liabilities	**5.8**	6.1
Future employee obligations *(note 9)*	**48.0**	48.1
	$ 1,047.9	$ 1,040.1
Shareholder's equity		
Common shares, no par value, unlimited shares authorized; September 30, 2021 and December 31, 2020 - 30 million shares issued and outstanding	**321.0**	321.0
Contributed surplus	**100.0**	100.0
Retained earnings	**196.7**	191.3
Accumulated other comprehensive loss	**(2.7)**	(2.7)
	615.0	609.6
	$ 1,662.9	$ 1,649.7

Commitments and contingencies *(note 10)*

Subsequent events *(note 14)*

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Consolidated Statements of Income *(unaudited)*

($ millions)	Three months ended September 30 **2021**	2020	Nine months ended September 30 **2021**	2020
REVENUE *(note 6)*	**$ 54.6**	$ 48.6	**$ 246.3**	$ 223.0
EXPENSES				
Cost of sales, exclusive of items shown separately	**13.4**	9.6	**91.6**	74.3
Operating and administrative	**25.3**	24.3	**79.2**	97.2
Accretion	**0.1**	—	**0.2**	0.1
Depreciation and amortization	**10.7**	9.9	**30.0**	27.8
	49.5	43.8	**201.0**	199.4
Income from equity investments	**4.6**	4.7	**5.6**	4.0
Unrealized gain (loss) on foreign exchange contracts *(note 8)*	**0.7**	(0.4)	**2.0**	—
Other income	**0.1**	0.2	**0.3**	0.6
Foreign exchange loss	**(0.1)**	(0.1)	**(0.3)**	(0.1)
Operating income	**10.4**	9.2	**52.9**	28.1
Interest expense				
Short-term debt	**(0.1)**	(0.1)	**(0.3)**	(0.4)
Long-term debt	**(7.0)**	(7.2)	**(20.6)**	(20.9)
Income before income taxes	**3.3**	1.9	**32.0**	6.8
Income tax expense (recovery) *(note 7)*				
Current	**0.4**	(0.5)	**0.8**	1.2
Deferred	**0.5**	1.9	**1.0**	(1.7)
Net income after taxes	**$ 2.4**	$ 0.5	**$ 30.2**	$ 7.3

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Consolidated Statements of Comprehensive Income

(unaudited)

($ millions)	Three months ended September 30 **2021**	2020	Nine months ended September 30 **2021**	2020
Net income after taxes	**$ 2.4**	$ 0.5	**$ 30.2**	$ 7.3
Other comprehensive income (loss), net of taxes	**—**	—	**—**	—
Comprehensive income, net of taxes	**$ 2.4**	$ 0.5	**$ 30.2**	$ 7.3

See accompanying notes to the condensed interim consolidated financial statements.

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

($ millions)	Three months ended September 30 **2021**	2020	Nine months ended September 30 **2021**	2020
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**	$ 100.5
Share option expense	**—**	—	**—**	0.2
Reclassified to share-based liability	**—**	—	**—**	(0.7)
Balance, end of period	**$ 100.0**	$ 100.0	**$ 100.0**	$ 100.0
Retained earnings				
Balance, beginning of period	**$ 202.6**	$ 191.4	**$ 191.3**	$ 200.2
Net income after taxes	**2.4**	0.5	**30.2**	7.3
Common share dividends	**(8.3)**	(7.8)	**(24.8)**	(23.4)
Balance, end of period	**$ 196.7**	$ 184.1	**$ 196.7**	$ 184.1
Accumulated other comprehensive loss				
Balance, beginning of period	**$ (2.7)**	$ (1.1)	**$ (2.7)**	$ (1.1)
Other comprehensive income (loss)	**—**	—	**—**	—
Balance, end of period	**$ (2.7)**	$ (1.1)	**$ (2.7)**	$ (1.1)
Total shareholder's equity	**$ 615.0**	$ 604.0	**$ 615.0**	$ 604.0

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Consolidated Statements of Cash Flows *(unaudited)*

($ millions)	Three months ended September 30 **2021**	2020	Nine months ended September 30 **2021**	2020
Cash from (used in) operations				
Net income after taxes	**$ 2.4**	$ 0.5	**$ 30.2**	$ 7.3
Items not involving cash:				
Depreciation and amortization expense	**10.7**	9.9	**30.0**	27.8
Accretion expense	**0.1**	—	**0.2**	0.1
Deferred income tax expense (recovery) *(note 7)*	**0.5**	1.9	**1.0**	(1.7)
Income from equity investments	**(4.6)**	(4.7)	**(5.6)**	(4.0)
Unrealized loss (gain) on foreign exchange contracts *(note 8)*	**(0.7)**	0.4	**(2.0)**	—
Other	**(0.8)**	(0.6)	**(1.5)**	(1.0)
Distributions from equity investment	**1.8**	1.1	**3.0**	1.7
Changes in operating assets and liabilities *(note 11)*	**1.7**	(10.6)	**19.4**	11.5
	$ 11.1	$ (2.1)	**$ 74.7**	$ 41.7
Investing activities				
Additions to property, plant and equipment	**(24.3)**	(19.1)	**(52.3)**	(42.3)
Additions to intangible assets	**(3.0)**	(3.5)	**(8.3)**	(8.1)
Proceeds from disposition of assets, net of transaction costs	**0.1**	0.2	**0.2**	0.2
Contributions to equity investments	**—**	—	**(0.1)**	—
	$ (27.2)	$ (22.4)	**$ (60.5)**	$ (50.2)
Financing activities				
Repayment of short-term debt	**(2.7)**	(2.7)	**(3.4)**	(12.1)
Net issuance (repayment) of bankers' acceptances	**26.5**	6.0	**9.5**	(47.4)
Issuance of long-term debt, net of debt issuance costs	**—**	—	**—**	99.1
Repayment of long-term debt	**(0.5)**	(0.5)	**(0.5)**	(0.5)
Common share dividends	**(8.3)**	(7.8)	**(24.8)**	(23.4)
Other	**(0.3)**	—	**(0.3)**	—
	$ 14.7	$ (5.0)	**$ (19.5)**	$ 15.7
Change in cash and cash equivalents	**(1.4)**	(29.5)	**(5.3)**	7.2
Cash and cash equivalents, beginning of period	**3.2**	36.9	**7.1**	0.2
Cash and cash equivalents, end of period	**$ 1.8**	$ 7.4	**$ 1.8**	$ 7.4

See accompanying notes to the condensed interim consolidated financial statements.

Notes to the Condensed Interim Consolidated Financial Statements

(unaudited)

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

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. On March 31, 2020, pursuant to a plan of arrangement (the "Arrangement"), TSU became 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 Teachers' Retirement Fund Board ("ATRF") indirectly holds a minority economic interest. ATRF's indirect legal ownership interest in TSU was transferred to Alberta Investment Management Corporation ("AIMCo") on February 1, 2021, and ATRF's interest in TSU is now held by AIMCo in its capacity as investment manager for the benefit of ATRF.

The Company owns rate-regulated natural gas distribution and transmission utility businesses through its 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 one-third equity interest in the utility that delivers natural gas to end-users in Inuvik, Northwest Territories.

2. BASIS OF PRESENTATION

Basis of Preparation

These consolidated financial statements have been prepared by management in accordance with United States Generally Accepted Accounting Principles ("U.S. GAAP").

Pursuant to National Instrument 52-107, "Acceptable Accounting Principles and Auditing Standards" ("NI 52-107"), 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 consolidated financial statements include the accounts of the Company and its direct and indirect subsidiaries, including, without limitation: TriSummit Utility Group Inc. (formerly AltaGas Utility Group Inc.), Bear Mountain Wind Limited Partnership, TriSummit Canadian Energy Holdings Ltd. (formerly AltaGas Canadian Energy Holdings Ltd.), PNG, AUI, and HGL. The consolidated financial statements also include investments in Inuvik Gas Ltd. and Northwest Hydro Limited Partnership ("Coast LP"), 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 consolidated financial statements in accordance with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the reported amounts of revenue and expenses during the period. Key areas where management has made complex or subjective judgments, when matters are inherently uncertain, include but are not limited to: 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 consolidated financial statements of future periods.

SIGNIFICANT ACCOUNTING POLICIES

Except as noted below, these condensed interim consolidated financial statements have been prepared following the same accounting policies and methods as those used in preparing the Company's 2020 annual audited consolidated financial statements.

ADOPTION OF NEW ACCOUNTING STANDARDS

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

- ASU No. 2019-12 "Income Taxes – Simplifying the Accounting for Income Taxes". The amendment in this ASU removes certain exceptions and provides some simplifications in accounting for income taxes. The adoption of this ASU did not have a material impact on the Company's consolidated financial statements; and

- ASU No. 2020-01 "Investments – Equity Securities (Topic 321), Investments – Equity Method and Joint Ventures (Topic 323) and Derivatives and Hedging (Topic 815) – Clarifying the Interactions between Topic 321, Topic 323, and Topic 815". The amendment in this ASU provides guidance for accounting for certain equity securities when the equity method of accounting is applied or discontinued and for forward contracts and purchased options on certain securities. The adoption of this ASU did not have a material impact on the Company's 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 consolidated financial statements.

4. SHORT-TERM DEBT

As at September 30, 2021, the Company held a $35.0 million (December 31, 2020 - $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 September 30, 2021, outstanding overdraft under this facility were $nil (December 31, 2020 - $nil). Letters of credit outstanding under this facility as at September 30, 2021 were $3.4 million (December 31, 2020 - $3.8 million).

As at September 30, 2021, the Company held a $25.0 million (December 31, 2020 - $25.0 million) bank operating facility which is available for PNG's working capital purposes and matures on 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 September 30, 2021, prime-rate advances under the operating facility were $0.8 million (December 31, 2020 - $4.1 million). Letters of credit outstanding under this facility as at September 30, 2021 were $5.1 million (December 31, 2020 - $4.7 million).

5. LONG-TERM DEBT

As at	Maturity date	**September 30, 2021**	December 31, 2020
Credit facilities			
$200 million unsecured revolving credit facility[a]	16-Jul-2025	**$ 33.5**	$ 24.0
$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**	11.5
PNG 2027 series debenture - 6.90 percent[c]	2-Dec-2027	**12.5**	12.5
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
		$ 732.4	$ 723.4
Less debt issuance costs and discount		**(3.1)**	(3.4)
		$ 729.3	$ 720.0
Less current portion		**(1.0)**	(1.0)
		$ 728.3	$ 719.0

(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 PP&E and gas purchase and gas sales contracts, and a first floating charge on other property, assets and undertakings.

6. REVENUE

The following table disaggregates revenue by major sources:

	Three months ended September 30, 2021			
	Renewable Energy	Utilities	Corporate	Total
Revenue from contracts with customers				
Gas sales and transportation services	$ —	$ 42.5	$ —	$ 42.5
Other	—	0.5	—	0.5
Total revenue from contracts with customers	$ —	$ 43.0	$ —	$ 43.0
Other sources of revenue				
Revenue from alternative revenue programs[(a)]	$ —	$ 6.4	$ —	$ 6.4
Leasing revenue[(b)]	$ 4.6	$ —	$ —	$ 4.6
Other	—	0.6	—	0.6
Total revenue from other sources	$ 4.6	$ 7.0	$ —	$ 11.6
Total revenue	$ 4.6	$ 50.0	$ —	$ 54.6

(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.

	Nine months ended September 30, 2021			
	Renewable Energy	Utilities	Corporate	Total
Revenue from contracts with customers				
Gas sales and transportation services	$ —	$ 226.8	$ —	$ 226.8
Other	—	1.4	—	1.4
Total revenue from contracts with customers	$ —	$ 228.2	$ —	$ 228.2
Other sources of revenue				
Revenue from alternative revenue programs[(a)]	$ —	$ 2.2	$ —	$ 2.2
Leasing revenue[(b)]	14.1	—	—	14.1
Other	—	1.8	—	1.8
Total revenue from other sources	$ 14.1	$ 4.0	$ —	$ 18.1
Total revenue	$ 14.1	$ 232.2	$ —	$ 246.3

(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 September 30, 2020								
		Renewable Energy		Utilities		Corporate		Total
Revenue from contracts with customers								
Gas sales and transportation services	$	—	$	37.8	$	—	$	37.8
Other		—		0.5		—		0.5
Total revenue from contracts with customers	$	—	$	38.3	$	—	$	38.3
Other sources of revenue								
Revenue from alternative revenue programs (a)	$	—	$	5.5	$	—	$	5.5
Leasing revenue(b)	$	4.1	$	—	$	—	$	4.1
Other		—		0.7		—		0.7
Total revenue from other sources	$	4.1	$	6.2	$	—	$	10.3
Total revenue	$	4.1	$	44.5	$	—	$	48.6

(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.

Nine months ended September 30, 2020								
		Renewable Energy		Utilities		Corporate		Total
Revenue from contracts with customers								
Gas sales and transportation services	$	—	$	207.2	$	—	$	207.2
Other		—		1.2		—		1.2
Total revenue from contracts with customers	$	—	$	208.4	$	—	$	208.4
Other sources of revenue								
Revenue from alternative revenue programs(a)	$	—	$	(0.2)	$	—	$	(0.2)
Leasing revenue(b)		12.9		—		—		12.9
Other		—		1.9		—		1.9
Total revenue from other sources	$	12.9	$	1.7	$	—	$	14.6
Total revenue	$	12.9	$	210.1	$	—	$	223.0

(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 September 30, 2021 include unbilled receivables of $10.9 million (December 31, 2020 - $30.6 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 September 30, 2021:

		Remainder of 2021		**2022**		**2023**		**2024**		**2025**		**> 2025**		**Total**
Gas sales and transportation services	$	3.1	$	11.3	$	8.7	$	4.2	$	1.8	$	11.7	**$**	**40.8**

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.

7. INCOME TAXES

For the three and nine months ended September 30, 2021, the Company recognized an income tax expense of $0.9 million and $1.8 million, respectively (three and nine months ended September 30, 2020 – income tax expense of $1.4 million and income tax recovery of $0.5 million, respectively). The decrease in income tax expense for the three months ended September 30, 2021 was mainly due to higher capital cost allowance deductions. The increase in income tax expense for the nine months ended September 30, 2021 was mainly due to higher taxable income as a result of the absence of transaction costs incurred in respect of the Arrangement in 2020, partially offset by higher capital cost allowance deductions.

8. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

The Company's financial instruments consist of accounts receivable, foreign exchange contracts, accounts payable and accrued liabilities, short-term debt, current portion of long-term debt, and long-term debt.

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. The Company estimates forward prices based on 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.

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.

					September 30, 2021
	Carrying Amount	**Level 1**	**Level 2**	**Level 3**	**Total Fair Value**
Financial assets					
Fair value through net income					
Foreign exchange contracts asset	**$ 0.6**	**$ —**	**$ 0.6**	**$ —**	**$ 0.6**
	$ 0.6	**$ —**	**$ 0.6**	**$ —**	**$ 0.6**
Financial liabilities					
Fair value through net income					
Foreign exchange contracts liability	**$ 0.1**	**$ —**	**$ 0.1**	**$ —**	**$ 0.1**
Amortized cost					
Current portion of long-term debt[(a)]	**$ 1.0**	**$ —**	**$ 1.0**	**$ —**	**$ 1.0**
Long-term debt[(a)]	**731.4**	**—**	**795.5**	**—**	**795.5**
	$ 732.5	**$ —**	**$ 796.6**	**$ —**	**$ 796.6**

(a) Excludes deferred financing costs and debt discount.

					December 31, 2020
	Carrying Amount	Level 1	Level 2	Level 3	Total Fair Value
Financial liabilities					
Fair value through net income					
Foreign exchange contracts liability	$ 1.5	$ —	$ 1.5	$ —	$ 1.5
Amortized cost					
Current portion of long-term debt[(a)]	$ 1.0	$ —	$ 1.0	$ —	$ 1.0
Long-term debt[(a)]	722.4	—	821.5	—	821.5
	$ 724.9	$ —	$ 824.0	$ —	$ 824.0

(a) Excludes deferred financing costs and debt discount.

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 2020 annual audited consolidated financial statements.

Credit and Liquidity Risks

The Company is continuing to monitor and adhere to guidance provided by the provincial governments and public health officials related to the novel coronavirus of 2019 ("COVID-19"). The Company continues to prioritize providing safe and reliable services to customers while ensuring the health and safety of its employees and the community. In response to COVID-19, both the Alberta Utilities Commission ("AUC") and British Columbia Utilities Commission ("BCUC") announced payment deferral programs in 2020.

In March 2020, the Government of Alberta announced a program for Albertans who were experiencing financial hardship directly related to the COVID-19 pandemic. The program allowed customers to defer payments of electricity and natural gas bills from March 18, 2020 until June 18, 2020 without any late fees or added interest payments. In addition, no Albertans could be disconnected from these services or see their services reduced during this period due to non-payment. Albertans who were enrolled in the bill deferral program were required to repay the deferred amount by June 18, 2021. On May 28, 2020, the AUC approved AUI's application to establish deferral accounts for the purposes of administering deferred payments under the Utility Payment Deferral Program Act (Alberta). As at June 18, 2021, AUI had approximately $0.4 million outstanding under these deferral accounts and an application for AUI's Utility Payment Deferral Program rate rider was submitted to the AUC on July 16, 2021. On August 18, 2021, the AUC approved AUI's application for Utility Payment Deferral Program balances to be included within a natural gas rate rider to be collected from all Alberta natural gas customers commencing November 1, 2021.

On June 10, 2020, the BCUC approved PNG's application to offer a bill payment deferral program between April 17, 2020 and June 30, 2020 to residential and small commercial customers that have experienced a loss of income or revenue as a result of the COVID-19 pandemic. The BCUC also granted approval for PNG to establish deferral accounts to capture unplanned costs incurred and cost savings as a result of the COVID-19 pandemic and to capture bad debts that may be incurred specifically as a result of the impact of COVID-19. PNG expects to apply for the amortization of the COVID-19 deferral accounts in future revenue requirement applications. As at September 30, 2021, $1.7 million of net cost savings have been identified and deferred as regulatory liabilities.

The Company is continuing to monitor customer accounts and while the Company has resumed normal collection activities, it is also continuing to work with customers impacted by COVID-19 on payment arrangements. While the COVID-19 pandemic did not significantly impact the carrying value of accounts receivable and the liquidity position of the Company as at September 30, 2021, given the unprecedented and changing developments surrounding the COVID-19 pandemic, it is not possible to reliably estimate the impact of the COVID-19 pandemic on the financial results and condition of the Company in future periods. As at September 30, 2021, the Company has approximately $219.0 million of cash balances and available credit facilities. The Company is continuing to monitor the potential impact of the pandemic on ongoing operations and associated financial implications.

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. In addition, the Company has entered into foreign exchange forward contracts to manage the foreign exchange risk from certain commitments denominated in U.S. dollars. As at September 30, 2021, the Company had outstanding foreign exchange forward contracts for US$18.6 million at an average rate of $1.24 Canadian per U.S. dollar. As at December 31, 2020, the Company had outstanding foreign exchange forward contracts for US$20.1 million at an average rate of $1.35 Canadian per U.S. dollar.

9. 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 September 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 Consolidated Statements of Income.
(b) Recorded under the line item "Other income (loss)" on the Consolidated Statements of Income.

Nine months ended September 30, 2021		Defined Benefit		Post-Retirement Benefits		Total
Current service cost [(a)]	**$**	**6.6**	**$**	**0.6**	**$**	**7.2**
Interest cost [(b)]		**2.7**		**0.3**		**3.0**
Expected return on plan assets [(b)]		**(4.5)**		**(0.3)**		**(4.8)**
Amortization of regulatory asset [(b)]		**1.8**		**—**		**1.8**
Net benefit cost recognized	**$**	**6.6**	**$**	**0.6**	**$**	**7.2**

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

Three months ended September 30, 2020		Defined Benefit		Post-Retirement Benefits		Total
Current service cost[(a)]	$	1.8	$	0.2	$	2.0
Interest cost[(b)]		1.0		0.1		1.1
Expected return on plan assets[(b)]		(1.6)		(0.1)		(1.7)
Amortization of regulatory asset[(b)]		0.4		—		0.4
Net benefit cost recognized	$	1.6	$	0.2	$	1.8

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

Nine months ended September 30, 2020		Defined Benefit		Post-Retirement Benefits		Total
Current service cost [(a)]	$	5.4	$	0.6	$	6.0
Interest cost [(b)]		3.0		0.3		3.3
Expected return on plan assets [(b)]		(4.8)		(0.3)		(5.1)
Amortization of regulatory asset [(b)]		1.2		—		1.2
Net benefit cost recognized	$	4.8	$	0.6	$	5.4

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

10. COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

During the third quarter of 2021, HGL entered into a building lease agreement with an initial term of fifteen years after commencement of the lease. The lease will commence upon the completion of the construction of the building. The total lease payments over the lease term are expected to be approximately $7.9 million. In addition, effective October 7, 2021, Bear Mountain Wind Park entered into a five-year service and maintenance contract for the wind turbines commencing on December 7, 2021. The total payments over the term of the contract are expected to be approximately $11.5 million. Other than as noted, there were no material changes in commitments from those disclosed in the Company's 2020 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 September 30, 2021, the Company had guarantees with an aggregate maximum of US$55.0 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 the Company. 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.

11. SUPPLEMENTAL CASH FLOW INFORMATION

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

	Three months ended September 30		Nine months ended September 30	
	2021	2020	**2021**	2020
Source (use) of cash:				
Accounts receivable	**$ (0.4)**	$ (1.8)	**$ 32.1**	$ 31.9
Inventory	**(1.7)**	(0.7)	**(2.2)**	(1.2)
Other current assets	**1.0**	0.1	**0.2**	(0.1)
Regulatory assets (current)	**(1.0)**	(1.8)	**(1.4)**	(1.0)
Accounts payable and accrued liabilities	**9.7**	(7.4)	**(7.9)**	(20.8)
Customer deposits	**1.4**	3.3	**(1.6)**	0.8
Regulatory liabilities (current)	**(3.5)**	0.4	**(2.8)**	(2.5)
Other current liabilities	**0.3**	0.2	**(0.4)**	(0.4)
Net change in regulatory assets and liabilities (long-term)[(a)]	**(4.2)**	(3.1)	**3.2**	4.5
Other long-term assets	**0.1**	0.2	**0.2**	0.3
Changes in operating assets and liabilities	**$ 1.7**	$ (10.6)	**$ 19.4**	$ 11.5

(a) Inclusive of an increase in the revenue deficiency account (use of cash) of $5.7 million and $2.5 million during the three and nine months ended September 30, 2021, respectively (three and nine months ended September 30, 2020 – an increase in the revenue deficiency account (use of cash) of $5.3 million and $1.4 million, respectively).

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

	Three months ended September 30		Nine months ended September 30	
	2021	2020	**2021**	2020
Interest paid	**$ 0.9**	$ 0.9	**$ 14.4**	$ 13.1
Income taxes paid (net of refunds)	**$ (3.1)**	$ 5.1	**$ (3.1)**	$ 5.7

12. 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 33.3 percent equity investment in Inuvik Gas Ltd.
Corporate	–	Includes the cost of providing shared services, financial and general corporate support and corporate assets.

The following tables show the composition by segment:

	Three months ended September 30, 2021				
	Utilities	**Renewable Energy**	**Corporate**	**Intersegment Elimination**	**Total**
Revenue	**$ 50.0**	**$ 4.6**	**$ —**	**$ —**	**$ 54.6**
Cost of sales	**(13.3)**	**(0.1)**	**—**	**—**	**(13.4)**
Operating and administrative	**(23.3)**	**(1.3)**	**(0.7)**	**—**	**(25.3)**
Accretion expense	**—**	**(0.1)**	**—**	**—**	**(0.1)**
Depreciation and amortization	**(8.9)**	**(1.8)**	**—**	**—**	**(10.7)**
Income (loss) from equity investments	**(0.1)**	**4.7**	**—**	**—**	**4.6**
Unrealized gain on foreign exchange contracts	**0.7**	**—**	**—**	**—**	**0.7**
Other income	**0.1**	**—**	**—**	**—**	**0.1**
Foreign exchange loss	**(0.1)**	**—**	**—**	**—**	**(0.1)**
Operating income (loss)	**$ 5.1**	**$ 6.0**	**$ (0.7)**	**$ —**	**$ 10.4**
Interest expense	**(1.4)**	**—**	**(5.7)**	**—**	**(7.1)**
Income (loss) before income taxes	**$ 3.7**	**$ 6.0**	**$ (6.4)**	**$ —**	**$ 3.3**
Net additions (reductions) to:					
Property, plant and equipment[(a)]	**$ 30.5**	**$ —**	**$ —**	**$ —**	**$ 30.5**
Intangible assets	**$ 3.6**	**$ —**	**$ —**	**$ —**	**$ 3.6**

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

	Nine months ended September 30, 2021				
	Utilities	**Renewable Energy**	**Corporate**	**Intersegment Elimination**	**Total**
Revenue	**$ 232.2**	**$ 14.1**	**$ —**	**$ —**	**$ 246.3**
Cost of sales	**(91.4)**	**(0.2)**	**—**	**—**	**(91.6)**
Operating and administrative	**(72.9)**	**(4.0)**	**(2.3)**	**—**	**(79.2)**
Accretion expense	**(0.1)**	**(0.1)**	**—**	**—**	**(0.2)**
Depreciation and amortization	**(24.4)**	**(5.5)**	**(0.1)**	**—**	**(30.0)**
Income from equity investments	**—**	**5.6**	**—**	**—**	**5.6**
Unrealized gain on foreign exchange contracts	**2.0**	**—**	**—**	**—**	**2.0**
Other income	**0.3**	**—**	**—**	**—**	**0.3**
Foreign exchange loss	**(0.3)**	**—**	**—**	**—**	**(0.3)**
Operating income (loss)	**$ 45.4**	**$ 9.9**	**$ (2.4)**	**$ —**	**$ 52.9**
Interest expense	**(4.2)**	**—**	**(16.7)**	**—**	**(20.9)**
Income (loss) before income taxes	**$ 41.2**	**$ 9.9**	**$ (19.1)**	**$ —**	**$ 32.0**
Net additions (reductions) to:					
Property, plant and equipment[(a)]	**$ 55.6**	**$ —**	**$ —**	**$ —**	**$ 55.6**
Intangible assets	**$ 8.4**	**$ —**	**$ 0.1**	**$ —**	**$ 8.5**

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

	Three months ended September 30, 2020				
	Utilities	Renewable Energy	Corporate	Intersegment Elimination	Total
Revenue	$ 44.5	$ 4.1	$ —	$ —	$ 48.6
Cost of sales	(9.5)	(0.1)	—	—	(9.6)
Operating and administrative	(22.8)	(1.0)	(0.5)	—	(24.3)
Depreciation and amortization	(8.1)	(1.8)	—	—	(9.9)
Income from equity investment	—	4.7	—	—	4.7
Unrealized loss on foreign exchange contracts	(0.4)	—	—	—	(0.4)
Other income	0.2	—	—	—	0.2
Foreign exchange loss	(0.1)	—	—	—	(0.1)
Operating income	$ 3.8	$ 5.9	$ (0.5)	$ —	$ 9.2
Interest expense	(1.6)	—	(5.7)	—	(7.3)
Income (loss) before income taxes	$ 2.2	$ 5.9	$ (6.2)	$ —	$ 1.9
Net additions (reductions) to:					
Property, plant and equipment[(a)]	$ 22.5	$ 0.1	$ —	$ —	$ 22.6
Intangible assets	$ 2.8	$ —	$ —	$ —	$ 2.8

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

	Nine months ended September 30, 2020				
	Utilities	Renewable Energy	Corporate	Intersegment Elimination	Total
Revenue	$ 210.1	$ 12.9	$ —	$ —	$ 223.0
Cost of sales	(74.1)	(0.2)	—	—	(74.3)
Operating and administrative	(69.9)	(3.5)	(23.8)	—	(97.2)
Accretion expense	—	(0.1)	—	—	(0.1)
Depreciation and amortization	(22.3)	(5.4)	(0.1)	—	(27.8)
Income from equity investments	—	4.0	—	—	4.0
Other Income	0.6	—	—	—	0.6
Foreign exchange loss	(0.1)	—	—	—	(0.1)
Operating income (loss)	$ 44.3	$ 7.7	$ (23.9)	$ —	$ 28.1
Interest expense	(4.4)	—	(16.9)	—	(21.3)
Income (loss) before income taxes	$ 39.9	$ 7.7	$ (40.8)	$ —	$ 6.8
Net additions (reductions) to:					
Property, plant and equipment[(a)]	$ 40.2	$ 0.2	$ —	$ —	$ 40.4
Intangible assets	$ 7.5	$ —	$ —	$ —	$ 7.5

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

The following table shows goodwill and total assets by segment:

		Utilities		Renewable Energy		Corporate		Total
As at September 30, 2021								
Goodwill	**$**	**119.1**	**$**	**—**	**$**	**—**	**$**	**119.1**
Segmented assets	**$**	**1,407.3**	**$**	**307.2**	**$**	**(51.6)**	**$**	**1,662.9**
As at December 31, 2020								
Goodwill	$	119.1	$	—	$	—	$	119.1
Segmented assets	$	1,375.0	$	297.4	$	(22.7)	$	1,649.7

13. 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.

14. SUBSEQUENT EVENTS

Subsequent events have been reviewed through November 3, 2021, the date on which these consolidated financial statements were approved for issue by the Board of Directors. Other than as disclosed under note 10, there were no subsequent events requiring disclosure or adjustment to the consolidated financial statements.