Quarterly Report to Shareholders

TC Energy

TC Energy reports solid second quarter 2022 results
High utilization continues across our system while advancing Canada's largest LNG solution

CALGARY, Alberta – July 28, 2022 – TC Energy Corporation (TSX, NYSE: TRP) (TC Energy or the Company) released its second quarter results today. TC Energy's President and Chief Executive Officer, François Poirier commented, "Through the first six months of 2022, we have delivered strong results reflecting the high utilization we continue to see across our entire system. Demand for clean, responsibly sourced natural gas remains high in North America, with energy security also driving incremental growth in the global LNG market." Poirier continued, "I am pleased to report we have reached a significant milestone with the Coastal GasLink Limited Partnership (Coastal GasLink LP), signing revised agreements with LNG Canada that will allow the safe and timely execution of our largest LNG-linked project. The 670-kilometre Coastal GasLink project is approximately 70 per cent complete, with mechanical in-service expected by the end of 2023. Together with LNG Canada, this project will provide the first direct path for Canadian natural gas to reach global LNG markets. By leveraging our competitive strengths, we continue to develop solutions to move, generate and store the energy North America relies on in a secure and increasingly sustainable way."

Highlights

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

- Consistent with our 2021 Annual Report outlook, 2022 comparable EBITDA is expected to be modestly higher than 2021, while 2022 comparable earnings per common share are expected to be consistent with 2021
- Second quarter 2022 results were underpinned by solid utilization and reliability across our assets. The continued need for energy security has placed renewed focus on the long-term role our infrastructure will play in responsibly fulfilling North America's energy demands:
  - Continued to deliver around a quarter of volumes destined for export from U.S. LNG facilities through our U.S. Natural Gas Pipelines and advanced 3.3 Bcf/d of additional projects during the first six months of the year
  - Total NGTL System deliveries averaged 12.8 Bcf/d, up nine per cent compared to second quarter 2021
  - U.S. Natural Gas Pipelines flows averaged 25.4 Bcf/d, up over three per cent compared to second quarter 2021
  - Bruce Power planned outages were completed ahead of schedule with results further augmented by the approximately $10/MWh increase in the contract power price that went into effect on April 1, 2022 related to the ongoing MCR program, asset management work and annual adjustments
  - During the quarter, the Keystone Pipeline System safely delivered nearly 610,000 Bbl/d as we placed approximately 30 per cent of the 2019 Open Season contracts into service effective April 1, 2022 with additional volumes anticipated through year end
- Second quarter 2022 financial results:
  - Net income attributable to common shares of $0.9 billion or $0.90 per common share compared to a net income of $1.0 billion or $1.00 per common share in 2021. Comparable earnings[1] of $1.0 billion or $1.00 per common share compared to $1.0 billion or $1.06 per common share in 2021
  - Segmented earnings of $1.7 billion compared to segmented earnings of $1.6 billion in 2021 and comparable EBITDA[1] of $2.4 billion compared to $2.2 billion in 2021
  - Net cash provided by operations of $0.9 billion compared to 2021 results of $1.7 billion and comparable funds generated from operations[1] was $1.6 billion compared to $1.8 billion in 2021

---

[1] Comparable earnings, comparable earnings per common share, comparable funds generated from operations and comparable EBITDA are non-GAAP measures used throughout this news release. These measures do not have any standardized meaning under GAAP and therefore are unlikely to be comparable to similar measures presented by other companies. The most directly comparable GAAP measures are Net income attributable to common shares, Net income per common share, Net cash provided by operations and Segmented earnings, respectively. For more information on non-GAAP measures, refer to the Non-GAAP section of this news release.

- Declared a quarterly dividend of $0.90 per common share for the quarter ending September 30, 2022
- Reinstated issuance of common shares from treasury at a two per cent discount under our Dividend Reinvestment Plan (DRP) commencing with the dividends declared on July 27, 2022 to prudently fund our growth program that includes increased project costs on the NGTL System and following our commitment to make an equity contribution of $1.9 billion to Coastal GasLink LP. We expect the DRP will be activated for a period of four quarters based on historical participation
- Continued to advance our $28 billion secured capital program, with $1.5 billion invested in second quarter 2022
- Reached revised project agreements with LNG Canada on the Coastal GasLink project which is now approximately 70 per cent complete
- To date in 2022, finalized contracts for approximately 580 MW and 240 MW from wind energy and solar projects, respectively, that will largely be used to provide renewable power to portions of the Keystone Pipeline System. We expect to finalize additional contracts in 2022.

(millions of $, except per share amounts)	three months ended June 30 2022	2021	six months ended June 30 2022	2021
Income				
Net income/(loss) attributable to common shares	**889**	975	**1,247**	(82)
per common share – basic	**$0.90**	$1.00	**$1.27**	($0.08)
Segmented earnings				
Canadian Natural Gas Pipelines	**385**	361	**743**	717
U.S. Natural Gas Pipelines	**711**	688	**1,021**	1,561
Mexico Natural Gas Pipelines	**162**	138	**282**	290
Liquids Pipelines	**261**	250	**533**	(2,258)
Power and Storage	**170**	158	**246**	321
Corporate	**(10)**	(36)	**21**	(4)
Total segmented earnings	**1,679**	1,559	**2,846**	627
Comparable EBITDA				
Canadian Natural Gas Pipelines	**681**	684	**1,325**	1,370
U.S. Natural Gas Pipelines	**915**	879	**2,022**	1,934
Mexico Natural Gas Pipelines	**190**	164	**338**	344
Liquids Pipelines	**341**	366	**670**	759
Power and Storage	**252**	157	**409**	335
Corporate	**(10)**	(4)	**(7)**	(7)
Comparable EBITDA	**2,369**	2,246	**4,757**	4,735
Depreciation and amortization	**(635)**	(633)	**(1,261)**	(1,278)
Interest expense	**(620)**	(577)	**(1,200)**	(1,147)
Allowance for funds used during construction	**63**	64	**138**	114
Interest income and other included in comparable earnings	**17**	158	**84**	250
Income tax expense included in comparable earnings	**(173)**	(175)	**(352)**	(378)
Net income attributable to non-controlling interests	**(9)**	(6)	**(20)**	(75)
Preferred share dividends	**(33)**	(39)	**(64)**	(77)
Comparable earnings	**979**	1,038	**2,082**	2,144
Comparable earnings per common share	**$1.00**	$1.06	**$2.12**	$2.22
Net cash provided by operations	**942**	1,711	**2,649**	3,377
Comparable funds generated from operations	**1,566**	1,754	**3,431**	3,777
Capital spending[1]	**1,482**	1,439	**3,206**	3,324
Dividends declared				
Per common share	**$0.90**	$0.87	**$1.80**	$1.74
Basic common shares outstanding (millions)				
– weighted average for the period	**983**	979	**982**	966
– issued and outstanding at end of period	**984**	979	**984**	979

1 Includes Capital expenditures and Contributions to equity investments.

CEO Message

Based on solid performance year-to-date, we reiterate that 2022 comparable EBITDA is expected to be modestly higher than 2021 and our 2022 comparable earnings per common share outlook is expected to be consistent with 2021. Please refer to the 2021 Annual Report for additional details. During the three months ended June 30, 2022, comparable earnings of $1.00 per common share and comparable funds generated from operations of $1.6 billion reflect the utility-like nature of our business together with contributions from projects that entered service in 2021 and 2022. By leveraging our competitive strengths, we continue to develop solutions to move, generate and store the energy North America relies on in a secure and increasingly sustainable way.

Results in the second quarter of 2022 are underpinned by high utilization rates across our asset base that continued to reliably meet North America's growing demand for energy. The NGTL System had total system deliveries averaging 12.8 Bcf/d, up nine per cent compared to second quarter 2021. Our U.S. Natural Gas Pipelines flows averaged 25.4 Bcf/d, up over three per cent year-over-year, which included a new all-time daily power load peak delivery of 2.75 Bcf on ANR. During the first six months, we continue to advance approximately 3.3 Bcf/d of LNG-linked projects in our U.S. Natural Gas business. Combining our U.S. Natural Gas projects with Coastal GasLink, TC Energy remains well positioned to continue to expand it's share of the North American LNG market. Bruce Power operational performance during the second quarter was exceptional with fewer outage days than planned. Project execution is on track, with Unit 6 MCR moving to the last part of the installation phase and remains on time and on budget. Additionally, during the quarter the Keystone Pipeline System safely delivered nearly 610,000 Bbl/d as we placed approximately 30 per cent of the 2019 Open Season contracts into service effective April 1, 2022 with additional volumes anticipated through year end.

We are also pleased to announce Coastal GasLink LP has achieved a significant milestone with the execution of revised project agreements with LNG Canada that incorporate a revised cost estimate for the project of $11.2 billion. The revised agreement allows us to continue the safe and timely execution of the 670-kilometre project which is now approximately 70 per cent complete, with two of eight sections finished and expected mechanical in-service by the end of 2023. The Wilde Lake compressor facility near Chetwynd at the eastern end of the route is also nearing completion, representing one of the most significant pieces of infrastructure on the project. Together with LNG Canada, the 2.1 Bcf/d project will provide the first direct path for western Canadian natural gas to reach global LNG markets, displacing coal-fired power and potentially reducing global GHG emissions by 60 to 90 million tonnes per year. Coastal GasLink LP is proud to be leading the way in terms of how energy projects are advanced in Canada, with over $1.4 billion in contracting opportunities awarded to Indigenous and local communities to date and with the recent 10 per cent equity option announcement with our Indigenous partners. In our view, global LNG fundamentals remain supportive of additional LNG exports from western Canada that we believe can be supported by the expansion of the Coastal GasLink project.

Our revised agreements with LNG Canada establish a better framework for project advancement and further strengthens our long-term partnership. The agreements resolve uncertainty over specific and anticipated costs, mitigate project funding and execution risks and allow us to continue the safe and timely execution of the project. We continue to believe the project remains economically viable and subject to a final investment decision, we anticipate a potential second phase of Coastal GasLink could enhance TC Energy's project returns.

Our industry-leading secured capital program is now $28 billion and we expect to sanction approximately $5 billion of projects per year throughout the decade. Importantly, our secured capital projects are largely underpinned by long-term take-or-pay contracts and/or regulated business models, giving us visibility to deliver earnings and cash flow growth, while reducing our GHG emissions intensity and continuing to lower our overall leverage metrics. As we stated at our 2021 Investor Day, our secured capital program is expected to deliver a 2021-2026 comparable EBITDA compounded annual growth rate of five per cent that will support our dividend growth, funding of capital commitments and reduction of our overall leverage metrics.

Looking forward, we have an extraordinary opportunity to support energy security and move toward a low carbon future. Our critical energy infrastructure assets are connecting North America's premier basins to LNG export facilities. We intend to continue expanding, extending and modernizing our existing natural gas pipeline network. Bruce Power's zero-emission power delivery continues to grow through our $4.4 billion life extension program, with more investments anticipated through this decade. We are also enhancing our existing liquids infrastructure and adding operational flexibility for our customers. Additionally, we see opportunities to originate new energy solutions like the Alberta Carbon Grid, large-scale hydrogen production, pumped hydro storage and solar and wind PPAs. We remain confident in our business plan and expect to continue to grow our common share dividend at an annual rate of three to five per cent. This is consistent with our conservative approach to capital allocation, historic risk-adjusted return profile and is expected to provide the capacity to fund our sizeable capital program while enhancing our financial strength and flexibility.

OUTLOOK

Comparable EBITDA and comparable earnings

- Our overall comparable EBITDA and comparable earnings per common share outlook for 2022 remains consistent with the 2021 Annual Report. 2022 comparable EBITDA is expected to be modestly higher than 2021 and 2022 comparable earnings per common share outlook is expected to be consistent with 2021. Please refer to the 2021 Annual Report for additional details. We continue to monitor the impact of changes in energy markets, our construction projects and regulatory proceedings as well as COVID-19 for any potential effect on our 2022 comparable EBITDA and comparable earnings per share.

Consolidated capital spending and equity investments

- Our total capital expenditures for 2022 are now expected to be approximately $8.5 billion. The increase from what was outlined in the 2021 Annual Report is primarily due to the partner equity contributions of approximately $1.3 billion we expect to make in 2022 to Coastal GasLink LP in accordance with revised agreements impacting Coastal GasLink LP. Refer to the Recent Developments – Canadian Natural Gas Pipelines section for additional information on the Coastal GasLink project. In addition, higher project costs are expected for the NGTL System reflecting inflationary pressures on labour and materials, additional regulatory conditions and other factors. We continue to monitor developments on all of our construction projects, work on cost mitigation strategies and assess market conditions as well as the impact of COVID-19 for further changes to our overall 2022 capital program.

NOTABLE RECENT DEVELOPMENTS INCLUDE:

Canadian Natural Gas Pipelines

- **Coastal GasLink**: Coastal GasLink LP and LNG Canada have reached a settlement that addresses and resolves disputes over certain incurred and anticipated costs of the Coastal GasLink pipeline project.

  As we have indicated previously, capital costs have increased from the original project cost estimate due to scope increases and the impacts of COVID-19, weather and other events outside of Coastal GasLink LP's control. The revised project agreements incorporate a new cost estimate for the project of $11.2 billion. Funding of the increased project cost estimate will be supported by an expansion of the existing project-level credit facilities and a further equity contribution by TC Energy. Mechanical in-service is expected to be reached by the end of 2023. Commercial in-service of the Coastal GasLink pipeline will occur after completion of commissioning the pipeline.

In recognition of the revised capital cost and revised project agreements with LNG Canada, and in accordance with a binding commitment subject to the execution of definitive agreements with our Coastal GasLink LP partners, we will make an equity contribution to Coastal GasLink LP of $1.9 billion, which will be paid in installments commencing in August 2022, with no resulting change to our 35 per cent ownership. Any additional equity financing required to fund construction of the pipeline will initially be funded through an amended interest-bearing subordinated loan agreement between TC Energy and Coastal GasLink LP, which was originally put in place in fourth quarter 2021 to provide temporary financing to the project. Any amounts outstanding on this amended loan (plus accrued interest) will be repaid by the Coastal GasLink partners, including us, subsequent to the pipeline being placed in-service and final costs being determined. We currently estimate our portion of the equity contributions to Coastal GasLink LP over the project life to be approximately $2.1 billion, including the $1.9 billion equity contribution noted above.

Following execution of the revised project agreements with LNG Canada, the Coastal GasLink LP project-level credit facilities will be increased by $1.6 billion up to a total of $8.4 billion. In accordance with the binding commitment subject to the execution of definitive agreements with our Coastal GasLink LP partners, our commitment under the subordinated loan agreement between TC Energy and Coastal GasLink LP will be stepped down from the current $3.8 billion over time as capacity under the project-level credit facilities is increased and we make installment payments of the $1.9 billion equity contribution, as discussed above.

On March 9, 2022, we announced the signing of option agreements to sell a 10 per cent equity interest in Coastal GasLink LP to Indigenous communities across the project corridor. The opportunity to become business partners through equity ownership was made available to all 20 Nations holding existing agreements with Coastal GasLink LP. The Nations have established two entities that together currently represent 16 Indigenous communities that have confirmed their support for the option agreements. The equity option is exercisable after commercial in-service of the pipeline, subject to customary regulatory approvals and consents, including the consent of LNG Canada.

The Coastal GasLink project is approximately 70 per cent complete. The entire route has been cleared, grading is more than 75 per cent complete and more than 320 km of pipeline has been installed, with reclamation activities underway in many areas.

- **NGTL System**: In the six months ended June 30, 2022, the NGTL System placed approximately $1.5 billion of capacity projects in service.

U.S. Natural Gas Pipelines

- **ANR Section 4 Rate Case**: ANR filed a Section 4 rate case with FERC on January 28, 2022 requesting an increase to ANR's maximum transportation rates effective August 1, 2022, subject to refund upon completion of the rate proceeding. The rate case is progressing as expected as we continue to pursue a collaborative process to find a mutually beneficial outcome with our customers, FERC and other stakeholders through settlement negotiations.

Mexico Natural Gas Pipelines

- **Tula and Villa de Reyes**: The CFE initiated arbitration in June 2019 for the Tula and Villa de Reyes projects, disputing fixed capacity payments due to force majeure events. Arbitration proceedings are currently suspended while management continues to progress collaborative settlement discussions with the CFE.

  We successfully achieved mechanical completion of the Villa de Reyes project's lateral and north sections in April 2022. We expect to complete the construction of the Villa de Reyes project in early 2023, subject to the successful resolution of ongoing negotiations with neighbouring communities to obtain pending land access.

Power and Storage

- **Bruce Power Life Extension**: On March 7, 2022, the IESO verified Bruce Power's Unit 3 MCR program final cost and schedule duration estimate submitted in December 2021. The Unit 3 MCR program is scheduled to begin in first quarter 2023 with expected completion in 2026.

  Bruce Power's contract price increased by approximately $10 per MWh on April 1, 2022, in accordance with contract terms, reflecting capital to be invested under the Unit 3 MCR program and the 2022 to 2024 Asset Management program plus normal annual inflation adjustments.

- **Renewable Energy Contracts and/or Investment Opportunities**: Through an RFI process conducted in 2021, we are seeking potential contracts and/or investment opportunities in wind, solar and energy storage projects to meet the electricity needs of the U.S. portion of the Keystone Pipeline System and supply renewable energy products and services to industrial and oil and gas sectors proximate to our in-corridor demand. To date in 2022, we have finalized contracts for approximately 580 MW and 240 MW from wind energy and solar projects, respectively. We continue to evaluate the proposals received through the RFI process and expect to finalize additional contracts in 2022.

Other Energy Solutions

- **Hydrogen Hubs**: As part of our Joint Development Agreement with Nikola, on April 26, 2022, we announced a plan to evaluate a hydrogen production hub on 140 acres in Crossfield, Alberta, where we currently operate our natural gas storage facility. We expect a final investment decision by the end of 2023, subject to customary regulatory approvals.

- **Alberta Carbon Grid (ACG)**: In June 2021, we announced a partnership with Pembina Pipeline Corporation to jointly develop a world-scale carbon transportation and sequestration system which, when fully constructed, is expected to be capable of transporting more than 20 million tonnes of carbon dioxide annually. On March 29, 2022, the ACG received notice from the Government of Alberta that our Final Project Proposal to build and operate a carbon storage hub and gathering lines in Alberta's industrial heartland was among the successful proponents. The project has been invited to move forward into the next stage of the Province's CCUS process and enter into an evaluation agreement to further assess the viability of this project. Designed to be an open-access system, the ACG proposes to leverage existing right of ways and/or pipelines to connect the Alberta Industrial Heartland emissions region to a key sequestration location.

Corporate

- **Mexico Tax Audit**: In 2019, the Mexican tax authority, the Tax Administration Services (SAT), completed an audit of the 2013 tax return of one of our subsidiaries in Mexico. The audit resulted in a tax assessment that denied the deduction for all interest expense and an assessment of additional tax, penalties and financial charges totaling less than US$1 million. We disagreed with this assessment and commenced litigation to challenge it. In January 2022, we received the tax court's ruling on the 2013 tax return, which upheld the SAT assessment. From September 2021 to February 2022, the SAT issued assessments for tax years 2014 through 2017 which denied the deduction of all interest expense as well as assessed incremental withholding tax on the interest. These assessments totaled approximately US$490 million in income and withholding taxes, interest, penalties and other financial charges.

  On April 27, 2022, we settled with the SAT on all of the above matters for the tax years 2013 through 2021. In the six months ended June 30, 2022, we recorded US$152 million of income tax expense (inclusive of withholding taxes, interest, penalties and other financial charges).

- **Dividend Reinvestment Plan**: To prudently fund our growth program that includes increased project costs on the NGTL System and following our commitment to make an equity contribution of $1.9 billion to Coastal GasLink LP, we have reinstated issuance of common shares from treasury at a two per cent discount under our Dividend Reinvestment Plan commencing with the dividends declared on July 27, 2022.

Teleconference and Webcast

We will hold a teleconference and webcast on **Thursday, July 28, 2022** at **9 a.m. (MDT) / 11 a.m. (EDT)** to discuss our second quarter 2022 financial results and company developments. Presenters will include François Poirier, President and Chief Executive Officer; Joel Hunter, Executive Vice-President and Chief Financial Officer; and other members of the executive leadership team.

Members of the investment community and other interested parties are invited to participate by calling **1.800.319.4610**. No pass code is required. Please dial in 15 minutes prior to the start of the call. A live webcast of the teleconference will be available on TC Energy's website at www.TCEnergy.com/events or via the following URL: http://www.gowebcasting.com/11982.

A replay of the teleconference will be available two hours after the conclusion of the call until midnight EDT on August 4, 2022. Please call 1.855.669.9658 and enter pass code 9146.

The unaudited interim Condensed consolidated financial statements and Management's Discussion and Analysis (MD&A) are available on our website at www.TCEnergy.com and will be filed today under TC Energy's profile on SEDAR at www.sedar.com and with the U.S. Securities and Exchange Commission on EDGAR at www.sec.gov.

About TC Energy

We're a team of 7,000+ energy problem solvers working to move, generate and store the energy North America relies on. Today, we're taking action to make that energy more sustainable and more secure. We're innovating and modernizing to reduce emissions from our business. And, we're delivering new energy solutions – from natural gas and renewables to carbon capture and hydrogen – to help other businesses and industries decarbonize too. Along the way, we invest in the communities where we live and work to strengthen community resilience and build a stronger future, together.

TC Energy's common shares trade on the Toronto (TSX) and New York (NYSE) stock exchanges under the symbol TRP. To learn more, visit us at www.TCEnergy.com.

Forward-Looking Information

This release contains certain information that is forward-looking, including the sustainability commitments and targets contained in our 2021 Report on Sustainability and our GHG Emissions Reduction Plan, and is subject to important risks and uncertainties (such statements are usually accompanied by words such as "anticipate", "expect", "believe", "may", "will", "should", "estimate", "intend" or other similar words). Forward-looking statements in this document are intended to provide TC Energy security holders and potential investors with information regarding TC Energy and its subsidiaries, including management's assessment of TC Energy's and its subsidiaries' future plans and financial outlook. All forward-looking statements reflect TC Energy's beliefs and assumptions based on information available at the time the statements were made and as such are not guarantees of future performance. As actual results could vary significantly from the forward-looking information, you should not put undue reliance on forward-looking information and should not use future-oriented information or financial outlooks for anything other than their intended purpose. We do not update our forward-looking information due to new information or future events, unless we are required to by law. For additional information on the assumptions made, and the risks and uncertainties which could cause actual results to differ from the anticipated results, refer to the most recent Quarterly Report to Shareholders and the 2021 Annual Report filed under TC Energy's profile on SEDAR at www.sedar.com and with the U.S. Securities and Exchange Commission at www.sec.gov and the "Forward-looking information" section of our 2021 Report on Sustainability and our GHG Emissions Reduction Plan which are available on our website at www.TCEnergy.com.

Non-GAAP Measures

This release contains references to the following non-GAAP measures: comparable earnings, comparable earnings per common share, comparable EBITDA and comparable funds generated from operations. These non-GAAP measures do not have any standardized meaning as prescribed by GAAP and therefore may not be comparable to similar measures presented by other entities. These non-GAAP measures are calculated by adjusting certain GAAP measures for specific items we believe are significant but not reflective of our underlying operations in the period. These comparable measures are calculated on a consistent basis from period to period and are adjusted for specific items in each period, as applicable except as otherwise described in the Condensed consolidated financial statements and MD&A. Refer to: (i) each business segment for a reconciliation of comparable EBITDA to segmented earnings; (ii) Consolidated results section for reconciliations of comparable earnings and comparable earnings per common share to Net income attributable to common shares and Net income per common share, respectively; and (iii) Financial condition section for a reconciliation of comparable funds generated from operations to Net cash provided by operations. Refer to the Non-GAAP measures section of the MD&A in our most recent quarterly report for more information about the non-GAAP measures we use, which section of the MD&A is incorporated by reference herein. The MD&A can be found on SEDAR (www.sedar.com) under TC Energy's profile.

Additional Information

This release should also be read in conjunction with our December 31, 2021 audited Consolidated financial statements and notes and the MD&A in our 2021 Annual Report. Capitalized abbreviated terms that are used but not otherwise defined herein are defined in our 2021 Annual Report. Certain comparative figures have been adjusted to reflect the current period's presentation.

Media Inquiries:
Jaimie Harding / Hejdi Carlsen
media@tcenergy.com
403.920.7859 or 800.608.7859

Investor & Analyst Inquiries:
Gavin Wylie / Hunter Mau
investor_relations@tcenergy.com
403.920.7911 or 800.361.6522

Quarterly report to shareholders

Second quarter 2022

Financial highlights

	three months ended June 30		six months ended June 30	
(millions of $, except per share amounts)	**2022**	2021	**2022**	2021
Income				
Revenues	**3,637**	3,182	**7,137**	6,563
Net income/(loss) attributable to common shares	**889**	975	**1,247**	(82)
per common share – basic	**$0.90**	$1.00	**$1.27**	($0.08)
Comparable EBITDA[1]	**2,369**	2,246	**4,757**	4,735
Comparable earnings	**979**	1,038	**2,082**	2,144
per common share	**$1.00**	$1.06	**$2.12**	$2.22
Cash flows				
Net cash provided by operations	**942**	1,711	**2,649**	3,377
Comparable funds generated from operations	**1,566**	1,754	**3,431**	3,777
Capital spending[2]	**1,482**	1,439	**3,206**	3,324
Dividends declared				
Per common share	**$0.90**	$0.87	**$1.80**	$1.74
Basic common shares outstanding (millions)				
– weighted average for the period	**983**	979	**982**	966
– issued and outstanding at end of period	**984**	979	**984**	979

1 Additional information on Segmented earnings, the most directly comparable GAAP measure, can be found in the Consolidated results section.

2 Includes Capital expenditures and Contributions to equity investments. Refer to the Financial conditions – Cash used in investing activities section for additional information.

Management's discussion and analysis

July 27, 2022

This management's discussion and analysis (MD&A) contains information to help the reader make investment decisions about TC Energy Corporation (TC Energy). It discusses our business, operations, financial position, risks and other factors for the three and six months ended June 30, 2022, and should be read with the accompanying unaudited Condensed consolidated financial statements for the three and six months ended June 30, 2022, which have been prepared in accordance with U.S. GAAP.

This MD&A should also be read in conjunction with our December 31, 2021 audited Consolidated financial statements and notes and the MD&A in our 2021 Annual Report. Capitalized abbreviated terms that are used but not otherwise defined herein are defined in our 2021 Annual Report. Certain comparative figures have been adjusted to reflect the current period's presentation.

FORWARD-LOOKING INFORMATION

We disclose forward-looking information to help the reader understand management's assessment of our future plans and financial outlook and our future prospects overall.

Statements that are ***forward looking*** are based on certain assumptions and on what we know and expect today and generally include words like ***anticipate, expect, believe, may, will, should, estimate*** or other similar words.

Forward-looking statements in this MD&A include information about the following, among other things:

- our financial and operational performance, including the performance of our subsidiaries
- expectations about strategies and goals for growth and expansion, including acquisitions
- expected cash flows and future financing options available, including portfolio management
- expected dividend growth
- expected access to and cost of capital
- expected costs and schedules for planned projects, including projects under construction and in development
- expected capital expenditures, contractual obligations, commitments and contingent liabilities
- expected regulatory processes and outcomes
- statements related to our GHG emissions reduction goals
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- the expected impact of future tax and accounting changes
- expected industry, market and economic conditions
- the expected impact of COVID-19.

Forward-looking statements do not guarantee future performance. Actual events and results could be significantly different because of assumptions, risks or uncertainties related to our business or events that happen after the date of this MD&A.

Our forward-looking information is based on the following key assumptions and subject to the following risks and uncertainties:

Assumptions

- realization of expected benefits from acquisitions, divestitures and energy transition
- regulatory decisions and outcomes
- planned and unplanned outages and the use of our pipeline, power and storage assets
- integrity and reliability of our assets
- anticipated construction costs, schedules and completion dates
- access to capital markets, including portfolio management
- expected industry, market and economic conditions
- inflation rates and commodity prices
- interest, tax and foreign exchange rates
- nature and scope of hedging
- expected impact of COVID-19.

Risks and uncertainties

- realization of expected benefits from acquisitions and divestitures
- our ability to successfully implement our strategic priorities and whether they will yield the expected benefits
- our ability to implement a capital allocation strategy aligned with maximizing shareholder value
- the operating performance of our pipeline, power and storage assets
- amount of capacity sold and rates achieved in our pipeline businesses
- the amount of capacity payments and revenues from our power generation assets due to plant availability
- production levels within supply basins
- construction and completion of capital projects
- cost and availability of, and inflationary pressure on labour, equipment and materials
- the availability and market prices of commodities
- access to capital markets on competitive terms
- interest, tax and foreign exchange rates
- performance and credit risk of our counterparties
- regulatory decisions and outcomes of legal proceedings, including arbitration and insurance claims
- our ability to effectively anticipate and assess changes to government policies and regulations, including those related to the environment and COVID-19
- our ability to realize the value of tangible assets and contractual recoveries, including those specific to the Keystone XL pipeline project
- competition in the businesses in which we operate
- unexpected or unusual weather
- acts of civil disobedience
- cyber security and technological developments
- ESG related risks
- impact of energy transition on our business
- economic conditions in North America as well as globally
- global health crises, such as pandemics and epidemics, including COVID-19 and the unexpected impacts related thereto.

You can read more about these factors and others in this MD&A and in other reports we have filed with Canadian securities regulators and the SEC, including the MD&A in our 2021 Annual Report.

As actual results could vary significantly from the forward-looking information, you should not put undue reliance on forward-looking information and should not use future-oriented information or financial outlooks for anything other than their intended purpose. We do not update our forward-looking statements due to new information or future events, unless we are required to by law.

FOR MORE INFORMATION

You can find more information about TC Energy in our Annual Information Form and other disclosure documents, which are available on SEDAR (www.sedar.com).

NON-GAAP MEASURES

This MD&A references the following non-GAAP measures:

- comparable EBITDA
- comparable EBIT
- comparable earnings
- comparable earnings per common share
- funds generated from operations
- comparable funds generated from operations.

These measures do not have any standardized meaning as prescribed by GAAP and therefore may not be comparable to similar measures presented by other entities. Discussions throughout this MD&A on the factors impacting comparable earnings, comparable earnings before interest, taxes, depreciation and amortization (comparable EBITDA) and comparable earnings before interest and taxes (comparable EBIT) are consistent with the factors that impact net income attributable to common shares and segmented earnings, respectively, except where noted otherwise.

Comparable measures

We calculate comparable measures by adjusting certain GAAP measures for specific items we believe are significant but not reflective of our underlying operations in the period. Except as otherwise described herein, these comparable measures are calculated on a consistent basis from period to period and are adjusted for specific items in each period, as applicable.

Our decision not to adjust for a specific item in reporting comparable measures is subjective and made after careful consideration. Specific items may include:

- gains or losses on sales of assets or assets held for sale
- income tax refunds, valuation allowances and adjustments resulting from changes in legislation and enacted tax rates
- unrealized fair value adjustments related to risk management activities and Bruce Power funds invested for post-retirement benefits
- legal, contractual, bankruptcy and other settlements
- impairment of goodwill, plant, property and equipment, investments and other assets
- acquisition and integration costs
- restructuring costs.

We exclude from comparable measures the unrealized gains and losses from changes in the fair value of derivatives related to financial and commodity price risk management activities. These derivatives generally provide effective economic hedges but do not meet the criteria for hedge accounting. Beginning in first quarter 2022, with retroactive restatement of prior periods, we exclude from comparable measures our proportionate share of the unrealized gains and losses from changes in the fair value of Bruce Power's investments held for post-retirement benefits and derivatives related to its risk management activities. These changes in fair value are recorded in net income. As these amounts do not accurately reflect the gains and losses that will be realized at settlement, we do not consider them reflective of our underlying operations.

We also exclude from comparable measures the unrealized foreign exchange gains and losses on the peso-denominated loan receivable from an affiliate as well as the corresponding proportionate share of Sur de Texas foreign exchange gains and losses, as the amounts do not accurately reflect the gains and losses that will be realized at settlement. These amounts offset within each reporting period, resulting in no impact on net income. This peso-denominated loan was fully repaid in first quarter 2022.

The following table identifies our non-GAAP measures against their most directly comparable GAAP measures.

Comparable measure	GAAP measure
comparable EBITDA	segmented earnings
comparable EBIT	segmented earnings
comparable earnings	net income attributable to common shares
comparable earnings per common share	net income per common share
funds generated from operations	net cash provided by operations
comparable funds generated from operations	net cash provided by operations

Comparable EBITDA and comparable EBIT

Comparable EBITDA represents segmented earnings adjusted for certain specific items, excluding non-cash charges for depreciation and amortization. We use comparable EBITDA as a measure of our earnings from ongoing operations as it is a useful indicator of our performance and is also presented on a consolidated basis. Comparable EBIT represents segmented earnings adjusted for specific items and is an effective tool for evaluating trends in each segment. Refer to each business segment for a reconciliation to segmented earnings.

Comparable earnings and comparable earnings per common share

Comparable earnings represents earnings attributable to common shareholders on a consolidated basis, adjusted for specific items. Comparable earnings is comprised of segmented earnings, Interest expense, AFUDC, Interest income and other, Income tax expense, Non-controlling interests and Preferred share dividends, adjusted for specific items. Refer to the Consolidated results section for reconciliations to Net income attributable to common shares and Net income per common share.

Funds generated from operations and comparable funds generated from operations

Funds generated from operations reflects net cash provided by operations before changes in operating working capital. The components of changes in working capital are disclosed in our 2021 Consolidated financial statements. We believe funds generated from operations is a useful measure of our consolidated operating cash flows because it excludes fluctuations from working capital balances, which do not necessarily reflect underlying operations in the same period, and is used to provide a consistent measure of the cash generating ability of our businesses. Comparable funds generated from operations is adjusted for the cash impact of specific items noted above. Refer to the Financial condition section for a reconciliation to Net cash provided by operations.

Consolidated results

	three months ended June 30		six months ended June 30	
(millions of $, except per share amounts)	**2022**	2021	**2022**	2021
Canadian Natural Gas Pipelines	**385**	361	**743**	717
U.S. Natural Gas Pipelines	**711**	688	**1,021**	1,561
Mexico Natural Gas Pipelines	**162**	138	**282**	290
Liquids Pipelines	**261**	250	**533**	(2,258)
Power and Storage	**170**	158	**246**	321
Corporate	**(10)**	(36)	**21**	(4)
Total segmented earnings	**1,679**	1,559	**2,846**	627
Interest expense	**(620)**	(583)	**(1,200)**	(1,153)
Allowance for funds used during construction	**63**	64	**138**	114
Interest income and other	**(43)**	127	**18**	189
Income/(loss) before income taxes	**1,079**	1,167	**1,802**	(223)
Income tax (expense)/recovery	**(148)**	(147)	**(471)**	293
Net income	**931**	1,020	**1,331**	70
Net income attributable to non-controlling interests	**(9)**	(6)	**(20)**	(75)
Net income/(loss) attributable to controlling interests	**922**	1,014	**1,311**	(5)
Preferred share dividends	**(33)**	(39)	**(64)**	(77)
Net income/(loss) attributable to common shares	**889**	975	**1,247**	(82)
Net income/(loss) per common share – basic	**$0.90**	$1.00	**$1.27**	($0.08)

Net income/(loss) attributable to common shares decreased by $86 million or $0.10 per common share and increased by $1.3 billion or $1.35 per common share for the three and six months ended June 30, 2022 compared to the same periods in 2021. The increase for the six months ended June 30, 2022 is primarily due to the $2.2 billion after-tax asset impairment of the Keystone XL pipeline project in first quarter 2021, partially offset by a $531 million after-tax goodwill impairment charge related to Great Lakes and a $195 million income tax expense for the settlement related to prior years' income tax assessments in Mexico in first quarter 2022 and also reflected the impact of common shares issued for the acquisition of TC PipeLines, LP in first quarter 2021.

The following specific items were recognized in Net income/(loss) attributable to common shares and were excluded from comparable earnings:

2022 results

- an after-tax goodwill impairment charge of $531 million in first quarter 2022 related to Great Lakes. Refer to the Other information – Critical accounting estimates and accounting policy changes section for additional information
- a $2 million and $195 million income tax expense for the three and six months ended June 30, 2022 for the settlement related to prior years' income tax assessments in Mexico
- after-tax preservation and storage costs for Keystone XL pipeline project assets of $3 million and $8 million for the three and six months ended June 30, 2022, which could not be accrued as part of the Keystone XL asset impairment charge
- $9 million and $24 million after-tax unrealized losses for the three and six months ended June 30, 2022 on our proportionate share of Bruce Power's fair value adjustment on funds invested for post-retirement benefits and risk management activities.

2021 results

- a $2.2 billion after-tax asset impairment charge, predominantly in first quarter 2021, net of expected contractual recoveries and other contractual and legal obligations, related to the termination of the Keystone XL pipeline project following the January 2021 revocation of the Presidential Permit
- after-tax preservation and storage costs for Keystone XL pipeline project assets of $16 million primarily in second quarter 2021, which could not be accrued as part of the Keystone XL impairment charge and interest expense on the Keystone XL project-level credit facility prior to its termination
- a $13 million after-tax recovery of certain costs from the IESO in second quarter 2021 associated with the Ontario natural gas-fired power plants sold in 2020
- a $2 million year-to-date after-tax unrealized gain on our proportionate share of Bruce Power's fair value adjustment on funds invested for post-retirement benefits and risk management activities.

Net income in both periods included unrealized gains and losses from changes in risk management activities which we exclude, along with the above noted items, to arrive at comparable earnings. A reconciliation of Net income/(loss) attributable to common shares to comparable earnings is shown in the following table.

RECONCILIATION OF NET INCOME/(LOSS) ATTRIBUTABLE TO COMMON SHARES TO COMPARABLE EARNINGS

	three months ended June 30		six months ended June 30	
(millions of $, except per share amounts)	**2022**	**2021**	**2022**	**2021**
Net income/(loss) attributable to common shares	**889**	975	**1,247**	(82)
Specific items (net of tax):				
Great Lakes goodwill impairment charge	**—**	—	**531**	—
Settlement of Mexico prior years' income tax assessments	**2**	—	**195**	—
Keystone XL asset impairment charge and other	**—**	2	**—**	2,194
Keystone XL preservation and other	**3**	16	**8**	16
Gain on sale of Ontario natural gas-fired power plants	**—**	(13)	**—**	(13)
Bruce Power unrealized fair value adjustments	**9**	—	**24**	(2)
Risk management activities[1]	**76**	58	**77**	31
Comparable earnings	**979**	1,038	**2,082**	2,144
Net income/(loss) per common share	**$0.90**	$1.00	**$1.27**	($0.08)
Specific items (net of tax):				
Great Lakes goodwill impairment charge	**—**	—	**0.54**	—
Settlement of Mexico prior years' income tax assessments	**—**	—	**0.20**	—
Keystone XL asset impairment charge and other	**—**	—	**—**	2.27
Keystone XL preservation and other	**0.01**	0.01	**0.01**	0.02
Gain on sale of Ontario natural gas-fired power plants	**—**	(0.01)	**—**	(0.01)
Bruce Power unrealized fair value adjustments	**0.01**	—	**0.02**	(0.01)
Risk management activities	**0.08**	0.06	**0.08**	0.03
Comparable earnings per common share	**$1.00**	$1.06	**$2.12**	$2.22

1 Risk management activities	three months ended June 30		six months ended June 30	
(millions of $)	2022	2021	2022	2021
U.S. Natural Gas Pipelines	**13**	(4)	**(2)**	2
Liquids Pipelines	**5**	(14)	**35**	10
Canadian Power	**3**	1	**(28)**	1
U.S. Power	**(4)**	—	**(4)**	—
Natural Gas Storage	**(58)**	2	**(65)**	3
Foreign exchange	**(60)**	(63)	**(38)**	(58)
Income tax attributable to risk management activities	**25**	20	**25**	11
Total unrealized losses from risk management activities	**(76)**	(58)	**(77)**	(31)

COMPARABLE EBITDA TO COMPARABLE EARNINGS

Comparable EBITDA represents segmented earnings adjusted for the specific items described above and excludes non-cash charges for depreciation and amortization. For further information on our reconciliation to comparable EBITDA refer to the business segment financial results sections.

	three months ended June 30		six months ended June 30	
(millions of $, except per share amounts)	2022	2021	2022	2021
Comparable EBITDA				
Canadian Natural Gas Pipelines	**681**	684	**1,325**	1,370
U.S. Natural Gas Pipelines	**915**	879	**2,022**	1,934
Mexico Natural Gas Pipelines	**190**	164	**338**	344
Liquids Pipelines	**341**	366	**670**	759
Power and Storage	**252**	157	**409**	335
Corporate	**(10)**	(4)	**(7)**	(7)
Comparable EBITDA	**2,369**	2,246	**4,757**	4,735
Depreciation and amortization	**(635)**	(633)	**(1,261)**	(1,278)
Interest expense	**(620)**	(577)	**(1,200)**	(1,147)
Allowance for funds used during construction	**63**	64	**138**	114
Interest income and other included in comparable earnings	**17**	158	**84**	250
Income tax expense included in comparable earnings	**(173)**	(175)	**(352)**	(378)
Net income attributable to non-controlling interests	**(9)**	(6)	**(20)**	(75)
Preferred share dividends	**(33)**	(39)	**(64)**	(77)
Comparable earnings	**979**	1,038	**2,082**	2,144
Comparable earnings per common share	**$1.00**	$1.06	**$2.12**	$2.22

Comparable EBITDA – 2022 versus 2021

Comparable EBITDA increased by $123 million for the three months ended June 30, 2022 compared to the same period in 2021 primarily due to the net effect of the following:

- higher Power and Storage EBITDA primarily attributable to increased Natural Gas Storage and other earnings from actively managing our natural gas positions in second quarter 2022 to capture favourable Alberta natural gas spreads as well as positive contributions from Bruce Power primarily due to a higher contract price that was partially offset by lower volumes resulting from greater planned outage days
- increased EBITDA in U.S. Natural Gas Pipelines primarily reflects a stronger U.S. dollar in 2022 with otherwise consistent earnings in second quarter 2022 versus the same period in 2021
- higher EBITDA from Mexico Natural Gas Pipelines predominantly driven by increased equity earnings from Sur de Texas due to lower interest expense attributable to the repayment of our peso-denominated loan with the subsequent issuance of a U.S. dollar-denominated loan on March 15, 2022
- decreased EBITDA from Liquids Pipelines as a result of lower contracted volumes on the U.S. Gulf Coast section of the Keystone Pipeline System, partially offset by higher contributions from liquids marketing activities, mainly attributable to higher margins
- consistent EBITDA in Canadian Natural Gas Pipelines reflecting lower flow-through costs on our Canadian rate-regulated pipelines offset by higher rate-base earnings on the NGTL System
- the positive foreign exchange impact of a stronger U.S. dollar on the Canadian dollar equivalent segmented earnings in our U.S. dollar-denominated operations. As detailed below, U.S. dollar-denominated comparable EBITDA decreased by US$25 million to US$1.1 billion compared to 2021; however, this was translated at a rate of 1.28 in 2022 versus 1.23 in 2021. Refer to the Foreign exchange discussion below for additional information.

Comparable EBITDA increased by $22 million for the six months ended June 30, 2022 compared to the same period in 2021 primarily due to the net effect of the following:

- increased EBITDA in U.S. Natural Gas Pipelines predominantly from increased earnings on Columbia Gas following the FERC-approved settlement for higher transportation rates effective February 2021, increased earnings from our mineral rights business and higher incremental earnings from growth projects placed in service, partially offset by higher property taxes
- higher Power and Storage EBITDA primarily attributable to increased Natural Gas Storage and other earnings from actively managing our natural gas positions in second quarter 2022 to capture favourable Alberta natural gas spreads as well as positive contributions from Bruce Power mainly due to a higher contract price that was partially offset by lower volumes resulting from greater planned outage days
- decreased EBITDA from Liquids Pipelines as a result of lower contracted volumes and marketing margins on the U.S. Gulf Coast section of the Keystone Pipeline System, partially offset by higher long-haul contracted volumes
- lower EBITDA from Canadian Natural Gas Pipelines largely attributable to the impact of lower flow-through costs on our Canadian rate-regulated pipelines, partially offset by higher rate-base earnings on the NGTL System
- the positive foreign exchange impact of a stronger U.S. dollar on the Canadian dollar equivalent segmented earnings in our U.S. dollar-denominated operations. As detailed below, U.S. dollar-denominated comparable EBITDA decreased by US$55 million to US$2.3 billion compared to 2021; however, this was translated at a rate of 1.27 in 2022 versus 1.25 in 2021. Refer to the Foreign exchange discussion below for additional information.

Due to the flow-through treatment of certain costs including income taxes, financial charges and depreciation in our Canadian rate-regulated pipelines, changes in these costs impact our comparable EBITDA despite having no significant effect on net income.

Comparable earnings – 2022 versus 2021

Comparable earnings decreased by $59 million or $0.06 per common share for the three months ended June 30, 2022 compared to the same period in 2021 and was primarily the net effect of:

- changes in comparable EBITDA described above
- lower Interest income and other mainly attributable to realized losses in 2022 compared to realized gains in 2021 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- higher Interest expense primarily due to higher long-term debt and junior subordinated note issuances, net of maturities, the foreign exchange impact of a stronger U.S. dollar in 2022 and higher interest rates on increased levels of short-term borrowings.

Comparable earnings decreased by $62 million or $0.10 per common share for the six months ended June 30, 2022 compared to the same period in 2021 and was primarily the net effect of:

- changes in comparable EBITDA described above
- lower Interest income and other mainly attributable to lower realized gains in 2022 compared to 2021 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- higher Interest expense primarily due to higher interest rates on increased levels of short-term borrowings, long-term debt and junior subordinated note issuances, net of maturities, the foreign exchange impact of a stronger U.S. dollar in 2022 and lower capitalized interest as a result of its cessation for the Keystone XL pipeline project following the revocation of the Presidential Permit in January 2021
- lower Net income attributable to non-controlling interests following the March 2021 acquisition of all outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy
- decreased Income tax expense primarily due to lower earnings and flow-through taxes, partially offset by higher U.S. state rate adjustments in 2021
- higher AFUDC primarily due to expansion projects in our Canadian and U.S. natural gas pipelines
- lower Depreciation and amortization in Canadian Natural Gas Pipelines on the Canadian Mainline, partially offset by higher depreciation on the NGTL System from expansion facilities that were placed in service and in U.S. Natural Gas Pipelines mainly due to the timing of certain adjustments related to the Columbia Gas rate case settlement.

Foreign exchange

Certain of our businesses generate all or most of their earnings in U.S. dollars and, since we report our financial results in Canadian dollars, changes in the value of the U.S. dollar against the Canadian dollar directly affect our comparable EBITDA and may also impact comparable earnings. As our U.S. dollar-denominated operations continue to grow, this exposure increases. A portion of the U.S. dollar-denominated comparable EBITDA exposure is naturally offset by U.S. dollar-denominated amounts below comparable EBITDA within Depreciation and amortization, Interest expense and other income statement line items. The balance of the exposure is actively managed on a rolling forward basis up to three years using foreign exchange derivatives; however, the natural exposure beyond that period remains. The net impact of the U.S. dollar movements on comparable earnings for the three and six months ended June 30, 2022 compared to the same periods in 2021, after considering natural offsets and economic hedges, was not significant.

The components of our financial results denominated in U.S. dollars are set out in the table below, including our U.S. and Mexico Natural Gas Pipelines operations along with the majority of our Liquids Pipelines business. Comparable EBITDA is a non-GAAP measure.

Pre-tax U.S. dollar-denominated income and expense items

	three months ended June 30		six months ended June 30	
(millions of US$)	**2022**	**2021**	**2022**	**2021**
Comparable EBITDA				
U.S. Natural Gas Pipelines	**716**	717	**1,591**	1,550
Mexico Natural Gas Pipelines[1]	**156**	151	**288**	310
Liquids Pipelines	**188**	217	**371**	445
	1,060	1,085	**2,250**	2,305
Depreciation and amortization	**(239)**	(224)	**(477)**	(442)
Interest on long-term debt and junior subordinated notes	**(318)**	(313)	**(623)**	(630)
Allowance for funds used during construction	**22**	23	**48**	40
Non-controlling interests and other	**(16)**	(4)	**(28)**	(50)
	509	567	**1,170**	1,223
Average exchange rate - U.S. to Canadian dollars	**1.28**	1.23	**1.27**	1.25

1 Excludes interest expense on our inter-affiliate loan with Sur de Texas which is fully offset in Interest income and other.

Outlook

Comparable EBITDA and comparable earnings

Our overall comparable EBITDA and comparable earnings per common share outlook for 2022 remains consistent with the 2021 Annual Report. We continue to monitor the impact of changes in energy markets, our construction projects and regulatory proceedings as well as COVID-19 for any potential effect on our 2022 comparable EBITDA and comparable earnings per share.

Consolidated capital spending and equity investments

Our total capital expenditures for 2022 are now expected to be approximately $8.5 billion. The increase from what was outlined in the 2021 Annual Report is primarily due to the partner equity contribution of approximately $1.3 billion we expect to make in 2022 to the Coastal GasLink Limited Partnership (Coastal GasLink LP) in accordance with revised agreements impacting Coastal GasLink LP. Refer to the Recent developments – Canadian Natural Gas Pipelines section for additional information on the Coastal GasLink project. In addition, higher project costs are expected for the NGTL System reflecting inflationary pressures on labour and materials, additional regulatory conditions and other factors. We continue to monitor developments on all of our construction projects, work on cost mitigation strategies and assess market conditions as well as the impact of COVID-19 for further changes to our overall 2022 capital program.

Capital program

We are developing quality projects under our capital program. These long-life infrastructure assets are supported by long-term commercial arrangements with creditworthy counterparties and/or regulated business models and are expected to generate significant growth in earnings and cash flows. In addition, many of these projects advance our goals to reduce our own carbon footprint as well as that of our customers.

Our capital program consists of approximately $28 billion of secured projects that represent commercially supported, committed projects that are either under construction or are in, or preparing to commence, the permitting stage.

Three years of maintenance capital expenditures for our businesses are included in the secured projects table. Maintenance capital expenditures on our regulated Canadian and U.S. natural gas pipelines are added to rate base on which we have the opportunity to earn a return and recover these expenditures through current or future tolls, which is similar to our capacity capital projects on these pipelines. Tolling arrangements in our liquids pipelines business provide for the recovery of maintenance capital expenditures.

During the six months ended June 30, 2022, we placed approximately $1.6 billion of capacity capital projects into service primarily related to the NGTL System. In addition, approximately $0.7 billion of maintenance capital expenditures were incurred.

All projects are subject to cost and timing adjustments due to factors including weather, market conditions, route refinement, permitting conditions, scheduling and timing of regulatory permits, as well as other potential restrictions and uncertainties, including the ongoing impact of COVID-19. Amounts exclude capitalized interest and AFUDC, where applicable.

Secured projects

Estimated and incurred project costs referred to in the following table include 100 per cent of the capital expenditures related to our wholly-owned projects and our share of equity contributions to fund projects within our equity investments, primarily Coastal GasLink and Bruce Power.

(billions of $)	Expected in-service date	Estimated project cost	Project costs incurred as at June 30, 2022
Canadian Natural Gas Pipelines			
NGTL System[1]	2022	3.4	2.8
	2023	2.5	0.3
	2024+	0.6	0.1
Canadian Mainline	2022	0.2	0.2
Coastal GasLink[2]	2023	2.1	0.2
Regulated maintenance capital expenditures	2022-2024	2.2	0.3
U.S. Natural Gas Pipelines			
Modernization III (Columbia Gas)	2022-2024	US 1.2	US 0.2
Delivery market projects	2025	US 1.5	—
Other capital	2022-2028	US 1.9	US 1.1
Regulated maintenance capital expenditures	2022-2024	US 2.1	US 0.3
Mexico Natural Gas Pipelines			
Villa de Reyes	2022-2023	US 1.0	US 0.9
Tula[3]	—	US 0.8	US 0.6
Liquids Pipelines			
Other capacity capital	2022-2023	US 0.2	US 0.1
Recoverable maintenance capital expenditures	2022-2024	0.3	—
Power and Storage			
Bruce Power – life extension[4]	2022-2027	4.4	2.1
Other			
Non-recoverable maintenance capital expenditures[5]	2022-2024	0.6	0.1
		25.0	**9.3**
Foreign exchange impact on secured projects[6]		**2.5**	**0.9**
Total secured projects (Cdn$)		**27.5**	**10.2**

1 Estimated project costs for 2022 and 2023 include $0.7 billion for Foothills related to the West Path Delivery Program.

2 Subsequent to revised project agreements executed between Coastal GasLink LP and LNG Canada and a binding commitment subject to the execution of definitive agreements with our partners in Coastal GasLink LP, the estimated project cost noted above represents our share of anticipated partner equity contributions to the project. Mechanical in-service is expected to be reached by the end of 2023. Commercial in-service of the Coastal GasLink pipeline will occur after completion of commissioning the pipeline. Refer to the Recent developments – Canadian Natural Gas Pipelines section for additional information on the settlement agreement and binding commitment related to Coastal GasLink.

3 The east section of the Tula pipeline is available for interruptible transportation services. We are working to procure necessary land access on the west section of the Tula pipeline to finalize its construction. The central segment construction has been delayed due to pending Indigenous consultation processes under the responsibility of the Secretary of Energy. Refer to the Recent developments – Mexico Natural Gas Pipelines section for additional information.

4 Reflects our expected share of cash contributions for the Bruce Power Unit 6 Major Component Replacement (MCR) program, expected to be in service in 2023, and the Unit 3 MCR, expected to be in service in 2026, as well as amounts to be invested under the Asset Management program through 2027 and the incremental uprate initiative. Refer to the Recent developments – Power and Storage section for additional information.

5 Includes non-recoverable maintenance capital expenditures from all segments and is primarily comprised of our proportionate share of maintenance capital expenditures for Bruce Power and other Power and Storage assets.

6 Reflects U.S./Canada foreign exchange rate of 1.29 at June 30, 2022.

Projects under development

In addition to our secured projects, we have a portfolio of projects that we are currently pursuing that are in varying stages of development. Projects under development have greater uncertainty with respect to timing and estimated project costs and are subject to corporate and regulatory approvals, unless otherwise noted. Each business segment has also outlined additional areas of focus for further ongoing business development activities and growth opportunities. As these projects are advanced and reach necessary milestones, they will be included in the secured projects table.

Canadian Natural Gas Pipelines

We continue to focus on optimizing the utilization and value of our existing Canadian Natural Gas Pipelines assets, including in-corridor expansions, providing connectivity to LNG export terminals and connections to growing shale gas supplies. Sustainability development projects are expected to include additional compressor station electrification and waste heat capture power generation on our systems as well as other GHG abatement initiatives.

U.S. Natural Gas Pipelines

Delivery Market Projects

Projects are in development that are expected to replace, upgrade and modernize certain U.S. Natural Gas Pipelines facilities while reducing emissions along portions of our pipeline systems in principal delivery markets. The enhanced facilities are expected to improve reliability of our systems and allow for additional transportation services under long-term contracts to address growing demand in the U.S. Midwest and the Mid-Atlantic regions, while reducing direct carbon dioxide equivalent emissions. Included in our secured projects are the US$0.7 billion VR Project on Columbia Gas and the US$0.8 billion WR Project on ANR, two delivery market projects that were approved in 2021 with expected in-service dates in the second half of 2025.

Renewable Natural Gas Hub Development

We announced a strategic collaboration with GreenGasUSA to explore development of a network of natural gas transportation hubs, including renewable natural gas (RNG). These transportation hubs would provide centralized access to existing energy transportation infrastructure for RNG sources, such as farms, wastewater treatment facilities and landfills. We believe that this collaboration will rapidly expand and provide incremental capability to the 10 current RNG interconnects across our U.S. natural gas pipeline footprint. The development of these hubs is an important step towards the acceleration of methane capture projects and the concurrent reduction of GHG emissions.

Other Opportunities

We are currently pursuing a variety of projects, including compression replacement, while furthering the electrification of our fleet, power generation and LDCs, expanding our modernization programs and in-corridor expansion opportunities on our existing systems. These projects are expected to improve the reliability of our systems with an environmental focus on cleaner energy.

We are also developing multiple transmission projects to link gas supply to the facilities that will meet the growing global demand for North American LNG.

Mexico Natural Gas Pipelines

We are currently evaluating new growth projects driven by Mexico's economic expansion and the need to connect natural gas to new regions of the country to serve power plants, industrial demand and LNG exports and, in doing so, reduce reliance on costly, carbon-intensive fuel oil. Potential projects include the completion of the central segment of Tula as well as a new offshore pipeline that would connect additional natural gas supply to Southeast Mexico and capacity expansions on existing assets.

Liquids Pipelines

Grand Rapids Phase II

Regulatory approvals have been obtained for Phase II of Grand Rapids, which consists of completing the 36-inch pipeline for crude oil service and converting the 20-inch pipeline from crude oil to diluent service. Commercial support is being pursued with prospective customers.

Terminals Projects

We continue to pursue projects associated with our terminals in Alberta and the U.S. to expand our core business and add operational flexibility for our customers.

Other Opportunities

We remain focused on maximizing the value of our liquids assets by expanding and leveraging our existing infrastructure and enhancing connectivity and service offerings to our customers. We are pursuing selective growth opportunities to add incremental value to our Liquids Pipelines business and expansions that leverage available capacity on our existing infrastructure. We remain disciplined in our approach and will position our business development activities strategically to capture opportunities within our risk preferences.

Power and Storage

Bruce Power

Life Extension Program

The continuation of Bruce Power's life extension program through to 2033 will require the investment of our proportionate share of Major Component Replacement (MCR) program costs on Units 4, 5, 7 and 8, as well as the remaining Asset Management program costs which continue beyond 2033, extending the life of Units 3 to 8 and the Bruce Power site to 2064. Preparation work for the Unit 4 MCR is well underway and work for the Unit 5, 7 and 8 MCRs has also begun. Future MCR investments will be subject to discrete decisions for each unit with specified off-ramps available to Bruce Power and the IESO. We expect to spend approximately $4.8 billion for our proportionate share of the Bruce Power MCR program costs for Units 4, 5, 7 and 8 and the remaining Asset Management program costs beyond 2027, as well as the incremental uprate initiative discussed below.

Uprate Initiative

Bruce Power's Project 2030 has a goal of achieving a site peak output of 7,000 MW by 2033 in support of climate change targets and future clean energy needs. Project 2030 is focused on continued asset optimization, innovation and leveraging new technology, which could include integration with storage and other forms of energy, to increase the site peak output. Project 2030 is arranged in three stages with the first two stages fully approved for execution. Stage 1 started in 2019 and is expected to add 150 MW of output and Stage 2, which began in early 2022, is targeting another 200 MW. Stage 3 requires Stages 1 and 2 to be complete and would enable an increase to the reactor power limit.

Development-Stage Projects

Ontario Pumped Storage

We continue to progress the development of the Ontario Pumped Storage project (OPSP), an energy storage facility located near Meaford, Ontario that would provide 1,000 MW of flexible, clean energy to Ontario's electricity system using a process known as pumped hydro storage.

The OPSP has been granted long-term land access to the fourth Canadian Division Training Centre for development of the project on this site from the Federal Minister of National Defence and has been included in Gate 2 of the IESO's Unsolicited Proposals Process. Once in service, this project would store emission-free energy when available and provide that energy to Ontario during periods of peak demand, thereby maximizing the value of existing emission-free generation in the province.

Saddlebrook Solar and Storage

We are proposing to construct and operate the Saddlebrook Solar and Storage project, a solar and energy storage solution that consists of a solar-generating facility located near Aldersyde, Alberta that will operate in conjunction with a battery energy storage system.

The proposed generating facility will produce approximately 81 MW of power and the battery storage system will provide up to 40 MWh of energy storage capacity and is expected to reduce GHG emissions by approximately 115,000 tonnes per year. The project is expected to be partially funded through Emissions Reduction Alberta's Biotechnology, Electricity and Sustainable Transportation Challenge. We expect to make an FID on the project in 2022 with the first phases of commissioning beginning in 2023.

Canyon Creek Pumped Storage

We are utilizing the existing site infrastructure from a decommissioned coal mine, located near Hinton, Alberta, to develop a pumped hydro storage project that is expected to have an initial generating capacity of 75 MW, expandable through future development to 400 MW. The facility is expected to provide up to 37 hours of on-demand, flexible, clean energy and ancillary services to the Alberta electricity grid. The project has received the approval of the Alberta Utilities Commission and the required approval of the Government of Alberta for hydro projects under the Dunvegan Hydro Development Act (Alberta).

The Canyon Creek Pumped Storage project is part of a larger product offering by us, a 24-by-7 carbon-free power product in the Province of Alberta and includes output from other projects currently under construction or being developed, thereby positioning our customers to manage hourly power needs with cost certainty and achieve decarbonization goals by sourcing power from emission-free assets.

Renewable Energy Contracts and/or Investment Opportunities

Through a Request for Information (RFI) process conducted in 2021, we are seeking potential contracts and/or investment opportunities in wind, solar and storage energy projects to meet the electricity needs of the U.S. portion of the Keystone Pipeline System and supply renewable energy products and services to industrial and oil and gas sectors proximate to our in-corridor demand. To date in 2022, we have finalized contracts for approximately 580 MW and 240 MW from wind energy and solar projects, respectively. We continue to evaluate the proposals received through the RFI process and expect to finalize additional contracts in 2022.

Other Opportunities

We are actively building our customer-focused origination platform across North America, providing commodity products and energy services to help customers address the challenges of energy transition. Our existing network of assets, customers and suppliers provide a mutual opportunity in which we can tailor solutions to meet their clean energy needs. Although we may adopt custom-tailored strategies, the core underpinning remains consistent, which is that every opportunity we undertake will ultimately be driven by customer needs allowing us to complement each other's capabilities, diversify risk and share learnings as we navigate the energy transition.

Other Energy Solutions

Our vision is to be the premier energy infrastructure company in North America today and in the future. That future includes embracing the energy transition that is underway and contributing to a lower-carbon energy world. As energy transition continues to evolve, we recognize a significant opportunity to reduce our emissions footprint, in addition to being a partner to our customers and other industries that are also looking for low-carbon solutions. Currently, it is uncertain how the energy mix will evolve and at what pace. We continue to observe a reliance on the existing sources of natural gas, crude oil and electricity, for which we currently provide services to our customers.

We are targeting five focus areas to reduce the emissions intensity of our operations, while also capturing growth opportunities that meet the energy needs of the future:

- modernize our existing system and assets
- decarbonize our energy consumption
- drive digital solutions and technologies
- leverage carbon credits and offsets
- invest in low-carbon energy and infrastructure, such as renewables along with emerging fuels and technology.

Alberta Carbon Grid (ACG)

In June 2021, we announced a partnership with Pembina Pipeline Corporation to jointly develop a world-scale system which, when fully constructed, is expected to be capable of transporting and sequestering more than 20 million tonnes of carbon dioxide annually. As an open-access system, ACG is intended to serve as the backbone for Alberta's emerging carbon capture utilization and storage (CCUS) industry. On March 29, 2022, the ACG received notice from the Government of Alberta that our proposal (the Final Project Proposal) to build and operate a carbon storage hub and gathering lines in Alberta's industrial heartland was among the successful proponents. The project has been invited to move forward into the next stage of the Province's CCUS process and enter into an evaluation agreement to further assess viability. The ACG proposes to leverage existing right of ways and/or pipelines to connect the Alberta Industrial Heartland emissions region to a key sequestration location.

Irving Oil Decarbonization

We have signed an MOU to explore the joint development of a series of proposed energy projects focused on reducing GHG emissions and creating new economic opportunities in New Brunswick and Atlantic Canada. Together with Irving Oil Ltd., we have identified a series of potential projects focused on decarbonizing existing assets and deploying emerging technologies to reduce overall emissions over the medium and long term. The partnership's initial focus will consider a suite of upgrade projects at Irving Oil's refinery in Saint John, New Brunswick, with the goal of significantly reducing emissions through the production and use of low-carbon power generation.

Hydrogen Hubs

We have entered into two Joint Development Agreements (JDA) to support customer-driven hydrogen production for long-haul transportation, power generation, large industrials and heating customers across the U.S. and Canada. The first opportunity is a partnership with Nikola Corporation (Nikola), a designer and manufacturer of zero-emission battery-electric and hydrogen-electric vehicles and related equipment, where Nikola will be a long-term anchor customer for hydrogen production infrastructure supporting hydrogen-fueled, zero-emission, heavy-duty trucks. The JDA with Nikola supports co-development of large-scale green and blue hydrogen production hubs, utilizing our power and natural gas infrastructure. On April 26, 2022, we announced a plan to evaluate a hydrogen production hub on 140 acres in Crossfield, Alberta, where we currently operate a natural gas storage facility. We expect an FID by the end of 2023, subject to customary regulatory approvals.

Our second customer-driven opportunity is a partnership with Hyzon Motors Inc. (Hyzon), a leader in fuel cell electric mobility for commercial vehicles, to develop hydrogen production facilities focused on zero-to-negative carbon intensity hydrogen from renewable natural gas, biogas and other sustainable sources. The facilities would be located close to demand, supporting Hyzon's back-to-base vehicle deployments. Our significant pipeline, storage and power assets can potentially be leveraged to lower the cost and increase the speed of development of these hubs. This may include exploring the integration of pipeline assets to enable hydrogen distribution and storage via pipeline and/or to deliver carbon dioxide to permanent sequestration sites to decarbonize the hydrogen production process.

Canadian Natural Gas Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure).

(millions of $)	three months ended June 30		six months ended June 30	
	2022	**2021**	**2022**	**2021**
NGTL System	**452**	408	**878**	805
Canadian Mainline	**188**	229	**358**	465
Other Canadian pipelines[1]	**41**	47	**89**	100
Comparable EBITDA	**681**	684	**1,325**	1,370
Depreciation and amortization	**(296)**	(323)	**(582)**	(653)
Comparable EBIT and segmented earnings	**385**	361	**743**	717

1 Includes results from Foothills, Ventures LP, Great Lakes Canada, our investment in TQM, Coastal GasLink development fee revenue as well as general and administrative and business development costs related to our Canadian Natural Gas Pipelines.

Canadian Natural Gas Pipelines comparable EBIT and segmented earnings increased by $24 million and $26 million for the three and six months ended June 30, 2022 compared to the same periods in 2021.

Net income and comparable EBITDA for our rate-regulated Canadian natural gas pipelines are primarily affected by our approved ROE, our investment base, the level of deemed common equity and incentive earnings. Changes in depreciation, financial charges and income taxes also impact comparable EBITDA, but do not have a significant impact on net income as they are almost entirely recovered in revenues on a flow-through basis.

NET INCOME AND AVERAGE INVESTMENT BASE

(millions of $)	three months ended June 30		six months ended June 30	
	2022	**2021**	**2022**	**2021**
Net income				
NGTL System	**176**	155	**346**	307
Canadian Mainline	**55**	53	**104**	104
Average investment base				
NGTL System			**17,110**	15,179
Canadian Mainline			**3,698**	3,692

Net income for the NGTL System increased by $21 million and $39 million for the three and six months ended June 30, 2022 compared to the same periods in 2021 mainly due to a higher average investment base resulting from continued system expansions. The NGTL System is operating under the 2020-2024 Revenue Requirement Settlement which includes an ROE of 10.1 per cent on 40 per cent deemed common equity. This settlement provides the NGTL System the opportunity to increase depreciation rates if tolls fall below specified levels and an incentive mechanism for certain operating costs where variances from projected amounts are shared with our customers.

Net income for the Canadian Mainline for the three and six months ended June 30, 2022 was consistent with the same periods in 2021. The Canadian Mainline is operating under the 2021-2026 Mainline Settlement which includes an approved ROE of 10.1 per cent on 40 per cent deemed common equity and an incentive to decrease costs and increase revenues on the pipeline under a beneficial sharing mechanism with our customers.

COMPARABLE EBITDA

Comparable EBITDA for Canadian Natural Gas Pipelines decreased by $3 million and $45 million for the three and six months ended June 30, 2022 compared to the same periods in 2021 due to the net effect of:

- lower flow-through depreciation on our regulated pipelines, as noted below
- higher rate-base earnings and flow-through financial charges on the NGTL System
- lower flow-through financial charges and income taxes on the Canadian Mainline
- lower Coastal GasLink development fee revenue due to timing of revenue recognition.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization decreased by $27 million and $71 million for the three and six months ended June 30, 2022 compared to the same periods in 2021 mainly due to one section of the Canadian Mainline being fully depreciated in third quarter 2021, partially offset by additional depreciation on the NGTL System from expansion facilities that were placed in service.

U.S. Natural Gas Pipelines

The table below is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure).

	three months ended June 30		six months ended June 30	
(millions of US$, unless otherwise noted)	**2022**	2021	**2022**	2021
Columbia Gas	**350**	355	**766**	763
ANR	**141**	150	**312**	301
Columbia Gulf	**46**	52	**105**	109
Great Lakes[1,2]	**35**	36	**92**	77
GTN[2,3]	**43**	40	**94**	55
Other U.S. pipelines[2,4]	**92**	77	**202**	137
TC PipeLines, LP[2,5]	**—**	—	**—**	24
Non-controlling interests[5]	**9**	7	**20**	84
Comparable EBITDA	**716**	717	**1,591**	1,550
Depreciation and amortization	**(169)**	(153)	**(336)**	(301)
Comparable EBIT	**547**	564	**1,255**	1,249
Foreign exchange impact	**151**	128	**339**	310
Comparable EBIT (Cdn$)	**698**	692	**1,594**	1,559
Specific items:				
Great Lakes goodwill impairment charge	**—**	—	**(571)**	—
Risk management activities	**13**	(4)	**(2)**	2
Segmented earnings (Cdn$)	**711**	688	**1,021**	1,561

1 Results reflect our 53.55 per cent direct interest in Great Lakes until March 2021 and our 100 per cent ownership interest subsequent to the March 2021 acquisition of all outstanding common units of TC PipeLines, LP not beneficially owned by us.

2 Our ownership interest in TC PipeLines, LP was 25.5 per cent prior to the acquisition in March 2021, at which time it became 100 per cent. Prior to March 2021, results reflected TC PipeLines, LP's 46.45 per cent interest in Great Lakes, its ownership of GTN, Bison, North Baja, Portland and Tuscarora as well as its share of equity income from Northern Border and Iroquois.

3 Reflects 100 per cent of GTN's comparable EBITDA subsequent to the TC PipeLines, LP acquisition in March 2021.

4 Reflects comparable EBITDA from our ownership in our mineral rights business (CEVCO), Crossroads and our share of equity income from Millennium and Hardy Storage, our U.S. natural gas marketing business as well as general and administrative and business development costs related to our U.S. natural gas pipelines. For the period subsequent to our March 2021 acquisition of TC PipeLines, LP, results also include 100 per cent of Bison, North Baja and Tuscarora, 61.7 per cent of Portland plus our equity income from Northern Border and Iroquois.

5 Reflects comparable EBITDA attributable to portions of TC PipeLines, LP and Portland that we did not own prior to our March 2021 acquisition of TC PipeLines, LP and subsequently reflects earnings attributable to the remaining 38.3 per cent interest in Portland we do not own.

U.S. Natural Gas Pipelines segmented earnings increased by $23 million and decreased by $540 million for the three and six months ended June 30, 2022 compared to the same periods in 2021 and included the following specific items which have been excluded from our calculation of comparable EBIT and comparable earnings:

- a pre-tax goodwill impairment charge of $571 million related to Great Lakes in first quarter 2022. Refer to the Other information – Critical accounting estimates and accounting policy changes section for additional information
- unrealized gains and losses from changes in the fair value of derivatives related to our U.S. natural gas marketing business.

A stronger U.S. dollar for the three and six months ended June 30, 2022 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to the same periods in 2021. Refer to the Consolidated results – Foreign exchange section for additional information.

Comparable EBITDA for U.S. Natural Gas Pipelines decreased by US$1 million and increased by US$41 million for the three and six months ended June 30, 2022 compared to the same periods in 2021 and was primarily due to the net effect of:

- incremental earnings from growth projects placed in service, mainly on ANR
- increased earnings for the six months ended June 30, 2022 on Columbia Gas following the FERC-approved settlement for higher transportation rates effective February 2021, partially offset by higher property taxes as a result of projects placed into service. Refer to the Recent developments – U.S. Natural Gas Pipelines section for additional information
- increased earnings from our mineral rights business due to higher commodity prices
- decreased earnings due to the impact of cold weather events and other discrete items recognized in 2021.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by US$16 million and US$35 million for the three and six months ended June 30, 2022 compared to the same periods in 2021 mainly due to new projects placed in service and the timing of certain depreciation adjustments related to the Columbia Gas rate case settlement.

Mexico Natural Gas Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure).

	three months ended June 30		six months ended June 30	
(millions of US$, unless otherwise noted)	**2022**	2021	**2022**	2021
Topolobampo	**39**	40	**80**	81
Sur de Texas[1]	**43**	27	**54**	61
Tamazunchale	**30**	31	**60**	62
Guadalajara	**19**	18	**37**	37
Mazatlán	**17**	18	**35**	35
Villa de Reyes	**1**	—	**—**	—
Comparable EBITDA	**149**	134	**266**	276
Depreciation and amortization	**(22)**	(22)	**(44)**	(44)
Comparable EBIT	**127**	112	**222**	232
Foreign exchange impact	**35**	26	**60**	58
Comparable EBIT and segmented earnings (Cdn$)	**162**	138	**282**	290

1 Represents equity income from our 60 per cent interest and fees earned from the construction and operation of the pipeline.

Mexico Natural Gas Pipelines segmented earnings increased by $24 million and decreased by $8 million for the three and six months ended June 30, 2022 compared to the same periods in 2021. A stronger U.S. dollar for the three and six months ended June 30, 2022 had a positive impact on the Canadian dollar equivalent segmented earnings compared to the same periods in 2021. Refer to the Consolidated results – Foreign exchange section for additional information.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$15 million and decreased by US$10 million for the three and six months ended June 30, 2022 compared to the same periods in 2021.

The increase in comparable EBITDA in second quarter 2022 compared to the same period in 2021 is primarily as a result of increased equity earnings in Sur de Texas due to lower interest expense attributable to the repayment of our peso-denominated loan with the subsequent issuance of a U.S. dollar-denominated loan which was entered into on March 15, 2022.

The decrease in comparable EBITDA for the six months ended June 30, 2022 compared to the same period in 2021 is primarily due to lower equity earnings in Sur de Texas due to a higher deferred income tax expense resulting from a foreign exchange gain, calculated for Mexico income tax purposes, on the revaluation of a U.S. dollar-denominated loan, partially offset by a reduction in interest expense on this loan.

Refer to the Financial risks and financial instruments – Related party transactions section for additional information.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization for the three and six months ended June 30, 2022 was consistent with the same periods in 2021.

Liquids Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings/(losses) (the most directly comparable GAAP measure).

	three months ended June 30		six months ended June 30	
(millions of $)	**2022**	**2021**	**2022**	**2021**
Keystone Pipeline System	**272**	311	**594**	629
Intra-Alberta pipelines[1]	**18**	23	**36**	45
Liquids marketing and other	**51**	32	**40**	85
Comparable EBITDA	**341**	366	**670**	759
Depreciation and amortization	**(80)**	(78)	**(161)**	(158)
Comparable EBIT	**261**	288	**509**	601
Specific items:				
Keystone XL asset impairment charge and other	**—**	(9)	**—**	(2,854)
Keystone XL preservation and other	**(5)**	(15)	**(11)**	(15)
Risk management activities	**5**	(14)	**35**	10
Segmented earnings/(losses)	**261**	250	**533**	(2,258)
Comparable EBITDA denominated as follows:				
Canadian dollars	**100**	100	**198**	204
U.S. dollars	**188**	217	**371**	445
Foreign exchange impact	**53**	49	**101**	110
Comparable EBITDA	**341**	366	**670**	759

1 Intra-Alberta pipelines include Grand Rapids, White Spruce and Northern Courier. In November 2021, we sold our remaining 15 per cent interest in Northern Courier.

Liquids Pipelines segmented earnings increased by $11 million and $2.8 billion for the three and six months ended June 30, 2022 compared to the same periods in 2021 and included the following specific items which have been excluded from our calculation of comparable EBIT and comparable earnings:

- a $9 million and $2,854 million pre-tax asset impairment charge, net of expected contractual recoveries and other contractual and legal obligations, for the three and six months ended June 30, 2021, associated with the termination of the Keystone XL pipeline project following the revocation of the Presidential Permit in January 2021
- pre-tax preservation and storage costs for Keystone XL pipeline project assets of $5 million and $11 million for the three and six months ended June 30, 2022 ($15 million for the three and six months ended June 30, 2021), which could not be accrued as part of the Keystone XL asset impairment charge
- unrealized gains and losses from changes in the fair value of derivatives related to our liquids marketing business.

A stronger U.S. dollar in 2022 relative to 2021 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. operations; however, comparable EBITDA from our U.S. dollar-denominated operations has decreased for the three and six months ended June 30, 2022. Refer to the Consolidated results – Foreign exchange section for additional information.

Comparable EBITDA for Liquids Pipelines decreased by $25 million and $89 million for the three and six months ended June 30, 2022 compared to the same periods in 2021 primarily due to the net effect of:

- lower contracted volumes on the U.S. Gulf Coast section of the Keystone Pipeline System, partially offset by higher long-haul contracted volumes as we placed approximately 30 per cent of the 2019 Open Season contracts into service effective April 1, 2022
- Liquids marketing achieved higher margins in the three months ended June 30, 2022, due to improved arbitrage opportunities compared to the same period in 2021. Earnings for the six months ended June 30, 2022 decreased relative to 2021 due to steep backwardation, combined with low inventory at key supply and trading hubs in first quarter 2022, which contributed to lower margins and market volatility negatively impacting marketing margins and the timing of earnings.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $2 million and $3 million for the three and six months ended June 30, 2022 compared to the same periods in 2021 primarily as a result of a stronger U.S. dollar.

Power and Storage

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure).

	three months ended June 30		six months ended June 30	
(millions of $)	**2022**	2021	**2022**	2021
Bruce Power[1]	**120**	90	**213**	181
Canadian Power	**75**	57	**135**	126
Natural Gas Storage and other	**57**	10	**61**	28
Comparable EBITDA	**252**	157	**409**	335
Depreciation and amortization	**(14)**	(19)	**(34)**	(38)
Comparable EBIT	**238**	138	**375**	297
Specific items:				
Gain on sale of Ontario natural gas-fired power plants	**—**	17	**—**	17
Bruce Power unrealized fair value adjustments	**(9)**	—	**(32)**	3
Risk management activities	**(59)**	3	**(97)**	4
Segmented earnings	**170**	158	**246**	321

1 Includes our share of equity income from Bruce Power.

Power and Storage segmented earnings increased by $12 million for the three months ended June 30, 2022 and decreased by $75 million for the six months ended June 30, 2022 compared to the same periods in 2021 and included the following specific items:

- a $17 million pre-tax recovery of certain costs from the IESO in second quarter 2021 associated with the Ontario natural gas-fired power plants sold in 2020
- our proportionate share of Bruce Power's unrealized gains and losses on funds invested for post-retirement benefits and risk management activities
- unrealized gains and losses from changes in the fair value of derivatives used to reduce commodity exposures in our Power and Storage business, which have been excluded from comparable EBIT.

Comparable EBITDA for Power and Storage increased by $95 million and $74 million for the three and six months ended June 30, 2022 compared to the same periods in 2021 primarily due to the net effect of:

- increased Natural Gas Storage and other results from active management of our natural gas positions in second quarter 2022 to capture favourable Alberta natural gas spreads. We expect these gains to be largely offset in the second half of 2022
- positive contributions from Bruce Power primarily due to a higher contract price, partially offset by lower volumes resulting from greater planned outage days
- improved Canadian Power earnings as a result of increased contributions from marketing activities.

DEPRECIATION AND AMORTIZATION

Lower depreciation and amortization for the three and six months ended June 30, 2022 compared to the same periods in 2021 was the result of certain adjustments in second quarter 2022.

BRUCE POWER

The following is our proportionate share of the components of comparable EBITDA and comparable EBIT.

(millions of $, unless otherwise noted)	three months ended June 30		six months ended June 30	
	2022	**2021**	**2022**	**2021**
Items included in comparable EBITDA and EBIT comprised of:				
Revenues[1]	**438**	405	**847**	806
Operating expenses	**(226)**	(238)	**(457)**	(463)
Depreciation and other	**(92)**	(77)	**(177)**	(162)
Comparable EBITDA and EBIT[2]	**120**	90	**213**	181
Bruce Power – other information				
Plant availability[3,4]	**79%**	85%	**82%**	85%
Planned outage days[4]	**127**	91	**204**	165
Unplanned outage days	**3**	7	**17**	22
Sales volumes (GWh)[5]	**4,702**	5,032	**9,677**	10,096
Realized power price per MWh[6]	**$92**	$81	**$87**	$80

1 Net of amounts recorded to reflect operating cost efficiencies shared with the IESO.

2 Represents our 48.3 per cent ownership interest and internal costs supporting our investment in Bruce Power. Excludes unrealized gains and losses on funds invested for post-retirement benefits and risk management activities.

3 The percentage of time the plant was available to generate power, regardless of whether it was running.

4 Excludes Unit 6 MCR outage days.

5 Sales volumes include deemed generation.

6 Calculation based on actual and deemed generation. Realized power price per MWh includes realized gains and losses from contracting activities and cost flow-through items. Excludes unrealized gains and losses on contracting activities and non-electricity revenues.

The Unit 6 MCR outage, which began in January 2020, is now in the installation phase. In second quarter 2022, planned outages were completed on Units 1 to 5. A second planned outage on Unit 4 is scheduled to begin in the second half of 2022. The average 2022 plant availability, excluding the Unit 6 MCR, is expected to be in the low-80 per cent range.

Corporate

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to Corporate segmented (losses)/earnings (the most directly comparable GAAP measure).

	three months ended June 30		six months ended June 30	
(millions of $)	**2022**	2021	**2022**	2021
Comparable EBITDA and EBIT	**(10)**	(4)	**(7)**	(7)
Specific item:				
Foreign exchange (losses)/gains – inter-affiliate loans[1]	**—**	(32)	**28**	3
Segmented (losses)/earnings	**(10)**	(36)	**21**	(4)

1 Reported in Income from equity investments in the Condensed consolidated statement of income.

Corporate segmented losses decreased by $26 million for the three months ended June 30, 2022 and Corporate segmented earnings increased by $25 million for the six months ended June 30, 2022 compared to the same periods in 2021. Corporate segmented (losses)/earnings included foreign exchange losses and gains on our proportionate share of peso-denominated inter-affiliate loans to the Sur de Texas joint venture from its partners up to March 15, 2022 when the peso-denominated inter-affiliate loans were fully repaid upon maturity. These foreign exchange losses and gains were recorded in Income from equity investments in the Corporate segment and were excluded from our calculation of comparable EBITDA and EBIT as they were fully offset by corresponding foreign exchange gains and losses on the inter-affiliate loan receivable included in Interest income and other. Refer to the Financial risks and financial instruments – Related party transactions section for additional information.

INTEREST EXPENSE

	three months ended June 30		six months ended June 30	
(millions of $)	**2022**	2021	**2022**	2021
Interest on long-term debt and junior subordinated notes				
Canadian dollar-denominated	**(190)**	(177)	**(367)**	(347)
U.S. dollar-denominated	**(318)**	(313)	**(623)**	(630)
Foreign exchange impact	**(88)**	(73)	**(169)**	(157)
	(596)	(563)	**(1,159)**	(1,134)
Other interest and amortization expense	**(28)**	(15)	**(47)**	(31)
Capitalized interest	**4**	1	**6**	18
Interest expense included in comparable earnings	**(620)**	(577)	**(1,200)**	(1,147)
Specific item:				
Keystone XL preservation and other	**—**	(6)	**—**	(6)
Interest expense	**(620)**	(583)	**(1,200)**	(1,153)

Interest expense increased by $37 million and $47 million for the three and six months ended June 30, 2022 compared to the same periods in 2021 and included $6 million in second quarter 2021 related to the Keystone XL project-level credit facility for the period following the January 2021 revocation of the Presidential Permit for the Keystone XL pipeline. This has been removed from our calculation of interest expense included in comparable earnings.

Interest expense included in comparable earnings increased by $43 million and $53 million for the three and six months ended June 30, 2022 compared to the same periods in 2021 primarily due to the net effect of:

- higher interest rates on increased levels of short-term borrowings
- long-term debt and junior subordinated note issuances, net of maturities. Refer to the Financial condition section for additional information
- reduced capitalized interest due to its cessation for the Keystone XL pipeline project following the revocation of the Presidential Permit in January 2021
- the foreign exchange impact from a stronger U.S. dollar on translation of U.S. dollar-denominated interest.

ALLOWANCE FOR FUNDS DURING CONSTRUCTION

	three months ended June 30		six months ended June 30	
(millions of $)	**2022**	**2021**	**2022**	**2021**
Canadian dollar-denominated	**35**	36	**77**	64
U.S. dollar-denominated	**22**	23	**48**	40
Foreign exchange impact	**6**	5	**13**	10
Allowance for funds used during construction	**63**	64	**138**	114

AFUDC decreased by $1 million and increased by $24 million for the three and six months ended June 30, 2022 compared to the same periods in 2021. The increase in AFUDC for the six months ended June 30, 2022 is primarily related to increased capital expenditures on our NGTL System and U.S. natural gas pipeline projects under construction.

INTEREST INCOME AND OTHER

	three months ended June 30		six months ended June 30	
(millions of $)	**2022**	**2021**	**2022**	**2021**
Interest income and other included in comparable earnings	**17**	158	**84**	250
Specific items:				
Foreign exchange gains/(losses) – inter-affiliate loan	**—**	32	**(28)**	(3)
Risk management activities	**(60)**	(63)	**(38)**	(58)
Interest income and other	**(43)**	127	**18**	189

Interest income and other decreased by $170 million and $171 million for the three and six months ended June 30, 2022 compared to the same periods in 2021 and included the following specific items which have been removed from our calculation of Interest income and other included in comparable earnings:

- foreign exchange gains and losses on the peso-denominated inter-affiliate loan receivable from the Sur de Texas joint venture to March 15, 2022, when it was fully repaid upon maturity
- unrealized gains and losses from changes in the fair value of derivatives used to manage our foreign exchange risk.

Our proportionate share of the corresponding foreign exchange losses and gains and interest expense on the peso-denominated inter-affiliate loans to the Sur de Texas joint venture from its partners were reflected in Income from equity investments in the Corporate and Mexico Natural Gas Pipelines segments, respectively. The foreign exchange gains and losses on these inter-affiliate loans were removed from comparable earnings. As part of refinancing activities with the Sur de Texas joint venture, on March 15, 2022, the peso-denominated loan discussed above was replaced with a new U.S. dollar-denominated loan of an equivalent $1.2 billion (US$938 million). The interest income and interest expense on both the peso-denominated and U.S. dollar-denominated loans were included in comparable earnings with all amounts offsetting and resulting in no impact on net income. Refer to the Financial risks and financial instruments – Related party transactions section for additional information.

Interest income and other included in comparable earnings decreased by $141 million for the three months ended June 30, 2022 compared to the same period in 2021 primarily due to realized losses in second quarter 2022 compared to realized gains for the same period in 2021 on derivatives used to manage our net exposure to foreign exchange rate fluctuation on U.S. dollar-denominated income. Interest income and other included in comparable earnings decreased by $166 million for the six months ended June 30, 2022 compared to the same period in 2021 due to lower realized gains in 2022 on these derivatives.

INCOME TAX (EXPENSE)/RECOVERY

	three months ended June 30		six months ended June 30	
(millions of $)	**2022**	**2021**	**2022**	**2021**
Income tax expense included in comparable earnings	**(173)**	(175)	**(352)**	(378)
Specific items:				
Great Lakes goodwill impairment charge	**—**	—	**40**	—
Settlement of Mexico prior years' income tax assessments	**(2)**	—	**(195)**	—
Keystone XL asset impairment charge and other	**—**	7	**—**	660
Keystone XL preservation and other	**2**	5	**3**	5
Gain on sale of Ontario natural gas-fired power plants	**—**	(4)	**—**	(4)
Bruce Power unrealized fair value adjustments	**—**	—	**8**	(1)
Risk management activities	**25**	20	**25**	11
Income tax (expense)/recovery	**(148)**	(147)	**(471)**	293

Income tax expense increased by $1 million and $764 million for the three and six months ended June 30, 2022 compared to the same periods in 2021 and included the following specific items which have been removed from our calculation of Income tax expense included in comparable earnings, in addition to the income tax impacts on other specific items referenced elsewhere in this MD&A:

- settlement of prior years' income tax assessments related to our operations in Mexico. Refer to the Recent developments – Corporate section for additional information
- the income tax impact of the Keystone XL pipeline project asset impairment charge and other in 2021.

Income tax expense included in comparable earnings decreased by $2 million and $26 million for the three and six months ended June 30, 2022 compared to the same periods in 2021 primarily due to lower pre-tax earnings and flow-through taxes, partially offset by higher U.S. state rate adjustments in 2021.

NET INCOME ATTRIBUTABLE TO NON-CONTROLLING INTERESTS

	three months ended June 30		six months ended June 30	
(millions of $)	**2022**	**2021**	**2022**	**2021**
Net income attributable to non-controlling interests	**(9)**	(6)	**(20)**	(75)

Net income attributable to non-controlling interests increased by $3 million and decreased by $55 million for the three and six months ended June 30, 2022 compared to the same periods in 2021. The decrease for the six months ended June 30, 2022 is primarily the result of the March 2021 acquisition of all outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy. Subsequent to the acquisition, TC PipeLines, LP became an indirect, wholly-owned subsidiary of TC Energy.

PREFERRED SHARE DIVIDENDS

	three months ended June 30		six months ended June 30	
(millions of $)	**2022**	**2021**	**2022**	**2021**
Preferred share dividends	**(33)**	(39)	**(64)**	(77)

Preferred share dividends decreased by $6 million and $13 million for the three and six months ended June 30, 2022 compared to the same periods in 2021 primarily due to the redemption of preferred shares in 2022 and 2021.

Recent developments

CANADIAN NATURAL GAS PIPELINES

Coastal GasLink

Coastal GasLink LP and LNG Canada have reached a settlement that addresses and resolves disputes over certain incurred and anticipated costs of the Coastal GasLink pipeline project.

As we have indicated previously, capital costs have increased from the original project cost estimate due to scope increases and the impacts of COVID-19, weather and other events outside of Coastal GasLink LP's control. The revised project agreements incorporate a new cost estimate for the project of $11.2 billion. Funding of the increased project cost estimate will be supported by an expansion of the existing project-level credit facilities and a further equity contribution by TC Energy. Mechanical in-service is expected to be reached by the end of 2023. Commercial in-service of the Coastal GasLink pipeline will occur after completion of commissioning the pipeline.

In recognition of the revised capital cost and revised project agreements with LNG Canada, and in accordance with a binding commitment subject to the execution of definitive agreements with our Coastal GasLink LP partners, we will make an equity contribution to Coastal GasLink LP of $1.9 billion, which will be paid in installments commencing in August 2022, with no resulting change to our 35 per cent ownership. Any additional equity financing required to fund construction of the pipeline will initially be funded through an amended interest-bearing subordinated loan agreement between TC Energy and Coastal GasLink LP, which was originally put in place in fourth quarter 2021 to provide temporary financing to the project. Any amounts outstanding on this amended loan (plus accrued interest) will be repaid by the Coastal GasLink partners, including us, subsequent to the pipeline being placed in-service and final costs being determined. We currently estimate our portion of the equity contributions to Coastal GasLink LP over the project life to be approximately $2.1 billion, including the $1.9 billion equity contribution noted above.

Following execution of the revised project agreements with LNG Canada, the Coastal GasLink LP project-level credit facilities will be increased by $1.6 billion up to a total of $8.4 billion. In accordance with the binding commitment subject to the execution of definitive agreements with our Coastal GasLink LP partners, our commitment under the subordinated loan agreement between TC Energy and Coastal GasLink LP will be stepped down from the current $3.8 billion over time as capacity under the project-level credit facilities is increased and we make installment payments of the $1.9 billion equity contribution, as discussed above.

On March 9, 2022, we announced the signing of option agreements to sell a 10 per cent equity interest in Coastal GasLink LP to Indigenous communities across the project corridor. The opportunity to become business partners through equity ownership was made available to all 20 Nations holding existing agreements with Coastal GasLink LP. The Nations have established two entities that together currently represent 16 Indigenous communities that have confirmed their support for the option agreements. The equity option is exercisable after commercial in-service of the pipeline, subject to customary regulatory approvals and consents, including the consent of LNG Canada.

The Coastal GasLink project is approximately 70 per cent complete. The entire route has been cleared, grading is more than 75 per cent complete and more than 320 km of pipeline has been installed, with reclamation activities underway in many areas.

NGTL System

In the six months ended June 30, 2022, the NGTL System placed approximately $1.5 billion of capacity projects in service.

2021 NGTL System Expansion Program

Construction of the 2021 NGTL System Expansion Program continues and, due to current market conditions as well as regulatory and weather delays, the estimated capital cost of the program is $3.4 billion. As of June 30, 2022, $2.4 billion of facilities have been placed into service, with the remaining facilities generally expected to be placed into service in the second half of 2022 and final completion anticipated in first quarter 2023. The program consists of 344 km (214 miles) of new pipeline, three compressor units and associated facilities and will add 1.6 PJ/d (1.5 Bcf/d) of incremental capacity to the NGTL System.

2022 NGTL System Expansion Program

We continue to advance construction of the 2022 NGTL System Expansion Program. As a result of current market conditions, material prices and regulatory delays, the estimated capital cost of the program is $1.5 billion with in-service dates anticipated in fourth quarter 2022 and second quarter 2023. The program consists of approximately 166 km (103 miles) of new pipeline, one new compressor unit and associated facilities and is underpinned by approximately 773 TJ/d (722 MMcf/d) of firm-service contracts with eight-year minimum terms.

NGTL System/Foothills West Path Delivery Program

On March 2, 2022, we received further regulatory approvals related to $0.5 billion of facilities, with approval on remaining applications anticipated in fourth quarter 2022. As a result of terrain complexity, current market conditions, material and labour cost increases and additional permitting conditions, the Canadian portion of the West Path Delivery Program has an estimated capital cost of $1.6 billion, with facilities' in-service dates anticipated in fourth quarter 2022 and fourth quarter 2023. The program consists of approximately 107 km (66 miles) of pipelines and associated facilities and is underpinned by 275 TJ/d (258 MMcf/d) of new firm-service contracts with terms that exceed 30 years.

U.S. NATURAL GAS PIPELINES

Columbia Gas Section 4 Rate Case

Columbia Gas reached a settlement with its customers effective February 2021 and received FERC approval on February 25, 2022. As part of the settlement, there is a moratorium on any further rate changes until April 1, 2025. Columbia Gas must file for new rates with an effective date no later than April 1, 2026. Previously accrued rate refund liabilities were refunded to customers, including interest, in second quarter 2022.

ANR Section 4 Rate Case

ANR filed a Section 4 rate case with FERC on January 28, 2022 requesting an increase to ANR's maximum transportation rates effective August 1, 2022, subject to refund upon completion of the rate proceeding. The rate case is progressing as expected as we continue to pursue a collaborative process to find a mutually beneficial outcome with our customers, FERC and other stakeholders through settlement negotiations.

Great Lakes

On March 18, 2022, Great Lakes reached an uncontested pre-filing settlement with its customers and filed an unopposed rate case settlement with FERC by which Great Lakes and the settling parties agreed to maintain existing recourse rates through October 31, 2025.

While the settlement created short-term rate certainty, it prompted a re-evaluation of Great Lakes’ long-term free cash flows which resulted in a US$451 million goodwill impairment charge being recorded in first quarter 2022. Refer to the Other information – Critical accounting estimates and accounting policy changes section for additional information.

KO Transmission Enhancement Acquisition

On April 28, 2022, we approved the approximately US$80 million acquisition of KO Transmission assets to be integrated into our Columbia Gas pipeline. After filing for and receiving FERC approval of Columbia Gas' acquisition of KO Transmission assets, which is expected by the end of 2022, this expanded footprint is also expected to provide additional last-mile connectivity of Columbia Gas into northern Kentucky and southern Ohio to growing LDC markets. It will also provide a platform for future capital investments including future conversions of coal-fueled power plants in the region.

Renewable Natural Gas Hub Development

In April 2022, we announced a strategic collaboration with GreenGasUSA to explore development of a network of natural gas transportation hubs, including RNG. These transportation hubs would provide centralized access to existing energy transportation infrastructure for RNG sources, such as farms, wastewater treatment facilities and landfills. We believe that this collaboration will rapidly expand and provide incremental capability to the 10 current RNG interconnects across our U.S. natural gas pipeline footprint. The development of these hubs is an important step towards the acceleration of methane capture projects and the concurrent reduction of GHG emissions.

Alberta XPress and North Baja XPress Projects

In April 2022, FERC provided certificate orders approving our Alberta XPress and North Baja XPress projects. The Alberta XPress project is an expansion of ANR that utilizes existing capacity on Great Lakes and the Canadian Mainline to connect growing supply from the WCSB to U.S. Gulf Coast LNG export markets. The anticipated in-service date is late 2022 or early 2023 with an estimated project cost of US$0.3 billion. The North Baja XPress project is designed to expand capacity on North Baja to meet increased customer demand by upgrading one existing compressor station and two existing meter stations in Arizona and California with a mid-2023 expected in-service date and total anticipated cost of $0.1 billion. All the upgrades required for North Baja XPress will occur on property and within facilities currently owned and/or operated by North Baja.

MEXICO NATURAL GAS PIPELINES

Tula and Villa de Reyes

The CFE initiated arbitration in June 2019 for the Tula and Villa de Reyes projects, disputing fixed capacity payments due to force majeure events. Arbitration proceedings are currently suspended while management continues to progress collaborative settlement discussions with the CFE.

We successfully achieved mechanical completion of the Villa de Reyes project's lateral and north sections in April 2022. We expect to complete the construction of the Villa de Reyes project in early 2023, subject to the successful resolution of ongoing negotiations with neighbouring communities to obtain pending land access.

POWER AND STORAGE

Bruce Power Life Extension

On March 7, 2022, the IESO verified Bruce Power's Unit 3 MCR program final cost and schedule duration estimate submitted in December 2021. The Unit 3 MCR program is scheduled to begin in first quarter 2023 with expected completion in 2026.

Bruce Power's contract price increased by approximately $10 per MWh on April 1, 2022, in accordance with contract terms, reflecting capital to be invested under the Unit 3 MCR program and the 2022 to 2024 Asset Management program plus normal annual inflation adjustments.

Renewable Energy Contracts and/or Investment Opportunities

Through an RFI process conducted in 2021, we are seeking potential contracts and/or investment opportunities in wind, solar and energy storage projects to meet the electricity needs of the U.S. portion of the Keystone Pipeline System and supply renewable energy products and services to industrial and oil and gas sectors proximate to our in-corridor demand. To date in 2022, we have finalized contracts for approximately 580 MW and 240 MW from wind energy and solar projects, respectively. We continue to evaluate the proposals received through the RFI process and expect to finalize additional contracts in 2022.

OTHER ENERGY SOLUTIONS

Hydrogen Hubs

As part of our JDA with Nikola, on April 26, 2022, we announced a plan to evaluate a hydrogen production hub on 140 acres in Crossfield, Alberta, where we currently operate our natural gas storage facility. We expect an FID by the end of 2023, subject to customary regulatory approvals.

Alberta Carbon Grid

In June 2021, we announced a partnership with Pembina Pipeline Corporation to jointly develop a world-scale carbon transportation and sequestration system which, when fully constructed, is expected to be capable of transporting more than 20 million tonnes of carbon dioxide annually. On March 29, 2022, the ACG received notice from the Government of Alberta that our Final Project Proposal to build and operate a carbon storage hub and gathering lines in Alberta's industrial heartland was among the successful proponents. The project has been invited to move forward into the next stage of the Province's CCUS process and enter into an evaluation agreement to further assess the viability of this project. Designed to be an open-access system, the ACG proposes to leverage existing right of ways and/or pipelines to connect the Alberta Industrial Heartland emissions region to a key sequestration location.

CORPORATE

Mexico Tax Audit

In 2019, the Mexican tax authority, the Tax Administration Services (SAT), completed an audit of the 2013 tax return of one of our subsidiaries in Mexico. The audit resulted in a tax assessment that denied the deduction for all interest expense and an assessment of additional tax, penalties and financial charges totaling less than US$1 million. We disagreed with this assessment and commenced litigation to challenge it. In January 2022, we received the tax court's ruling on the 2013 tax return, which upheld the SAT assessment. From September 2021 to February 2022, the SAT issued assessments for tax years 2014 through 2017 which denied the deduction of all interest expense as well as assessed incremental withholding tax on the interest. These assessments totaled approximately US$490 million in income and withholding taxes, interest, penalties and other financial charges.

On April 27, 2022, we settled with the SAT on all of the above matters for the tax years 2013 through 2021. In the six months ended June 30, 2022, we recorded US$152 million of income tax expense (inclusive of withholding taxes, interest, penalties and other financial charges).

Dividend Reinvestment Plan

To prudently fund our growth program that includes increased project costs on the NGTL System and following our commitment to make an equity contribution of $1.9 billion to Coastal GasLink LP, we have reinstated issuance of common shares from treasury at a two per cent discount under our Dividend Reinvestment Plan (DRP) commencing with the dividends declared on July 27, 2022.

Financial condition

We strive to maintain financial strength and flexibility in all parts of the economic cycle. We rely on our operating cash flows to sustain our business, pay dividends and fund a portion of our growth. In addition, we access capital markets and engage in portfolio management to meet our financing needs, manage our capital structure and to preserve our credit ratings.

We believe we have the financial capacity to fund our existing capital program through predictable and growing cash flows from operations, access to capital markets, portfolio management, joint ventures, asset-level financing, cash on hand and substantial committed credit facilities. Annually, in fourth quarter, we renew and extend our credit facilities as required.

At June 30, 2022, our current assets totaled $9.3 billion and current liabilities amounted to $14.5 billion, leaving us with a working capital deficit of $5.2 billion compared to $5.6 billion at December 31, 2021. Our working capital deficiency is considered to be in the normal course of business and is managed through:

- our ability to generate predictable and growing cash flows from operations
- a total of $10.1 billion of committed revolving credit facilities, of which $4.8 billion of short-term borrowing capacity remains available, net of $5.3 billion backstopping outstanding commercial paper balances. We also have arrangements in place for a further $2.4 billion of demand credit facilities of which $1.1 billion remained available as at June 30, 2022
- our access to capital markets, including through securities issuances, incremental credit facilities, portfolio management activities, DRP and Corporate ATM programs, if deemed appropriate.

CASH PROVIDED BY OPERATING ACTIVITIES

	three months ended June 30		six months ended June 30	
(millions of $)	**2022**	**2021**	**2022**	**2021**
Net cash provided by operations	**942**	1,711	**2,649**	3,377
Increase in operating working capital	**618**	27	**578**	259
Funds generated from operations	**1,560**	1,738	**3,227**	3,636
Specific items:				
Settlement of Mexico prior years' income tax assessments	**2**	—	**195**	—
Keystone XL preservation and other	**5**	21	**11**	21
Current income tax (recovery)/expense on Keystone XL asset impairment charge, preservation and other	**(1)**	(5)	**(2)**	120
Comparable funds generated from operations	**1,566**	1,754	**3,431**	3,777

Net cash provided by operations

Net cash provided by operations decreased by $769 million and $728 million for the three and six months ended June 30, 2022, compared to the same periods in 2021 primarily due to lower funds generated from operations as well as the amount and timing of working capital changes.

Comparable funds generated from operations

Comparable funds generated from operations, a non-GAAP measure, helps us assess the cash generating ability of our businesses by excluding the timing effects of working capital changes as well as the cash impact of our specific items.

Comparable funds generated from operations decreased by $188 million and $346 million for the three and six months ended June 30, 2022, compared to the same periods in 2021 primarily due to lower comparable earnings as described in the Consolidated results section, as well as lower distributions from operating activities of our equity investments.

CASH USED IN INVESTING ACTIVITIES

(millions of $)	three months ended June 30		six months ended June 30	
	2022	**2021**	**2022**	**2021**
Capital spending				
Capital expenditures	**(1,263)**	(1,214)	**(2,771)**	(2,859)
Contributions to equity investments	**(219)**	(225)	**(435)**	(465)
	(1,482)	(1,439)	**(3,206)**	(3,324)
Keystone XL contractual recoveries	**473**	—	**473**	—
Loans to affiliate repaid/(issued), net	**51**	(220)	**(112)**	(220)
Other distributions from equity investments	**32**	—	**32**	—
Deferred amounts and other	**(107)**	(98)	**(53)**	(404)
Net cash used in investing activities	**(1,033)**	(1,757)	**(2,866)**	(3,948)

Capital expenditures in 2022 were incurred primarily for the expansion of the NGTL System, ANR and Columbia Gas projects, as well as maintenance capital expenditures. Lower capital spending in 2022 compared to 2021 reflects the termination of the Keystone XL pipeline project following the revocation of the Presidential Permit in January 2021 as well as reduced spending on Columbia Gulf projects, partially offset by higher capital spending on the NGTL System.

Contributions to equity investments decreased in 2022 compared to 2021 mainly due to reduced cash calls from Bruce Power.

As part of refinancing activities with the Sur de Texas joint venture, on March 15, 2022, our peso-denominated loan was fully repaid upon maturity in the amount of $1.2 billion and was subsequently replaced with a new U.S. dollar-denominated loan of an equivalent $1.2 billion. Contributions to equity investments and Other distributions from equity investments are presented above on a net basis, although they are reported on a gross basis in our Condensed consolidated statement of cash flows. Refer to the Financial risks and financial instruments – Related party transactions section for additional information.

In the six months ended June 30, 2022, we received $473 million of contractual recoveries with respect to the Keystone XL pipeline project termination in 2021.

Loans to affiliate represent issuances and repayments on the subordinated demand revolving credit facility and the subordinated loan agreement that we entered into with Coastal GasLink LP to provide additional liquidity and funding to the project. Refer to the Financial risks and financial instruments – Related party transactions section for additional information.

CASH PROVIDED BY FINANCING ACTIVITIES

(millions of $)	three months ended June 30		six months ended June 30	
	2022	**2021**	**2022**	**2021**
Notes payable (repaid)/issued, net	**(116)**	247	**214**	(2,460)
Long-term debt issued, net of issue costs	**2,510**	1,822	**2,510**	7,751
Long-term debt repaid	**—**	—	**(26)**	(980)
Junior subordinated notes issued, net of issue costs	**(3)**	(1)	**1,008**	495
Redeemable non-controlling interest repurchased	**—**	—	**—**	(633)
Dividends and distributions paid	**(932)**	(898)	**(1,847)**	(1,749)
Common shares issued, net of issue costs	**29**	26	**158**	60
Preferred shares redeemed	**(1,000)**	(500)	**(1,000)**	(500)
Other	**12**	(10)	**17**	(15)
Net cash provided by financing activities	**500**	686	**1,034**	1,969

Long-term debt issued

The following table outlines significant long-term debt issuances in the six months ended June 30, 2022:

(millions of Canadian $, unless otherwise noted)					
Company	**Issue date**	**Type**	**Maturity date**	**Amount**	**Interest rate**
TRANSCANADA PIPELINES LIMITED					
	May 2022	Medium Term Notes	May 2032	800	5.33%
	May 2022	Medium Term Notes	May 2026	400	4.35%
	May 2022	Medium Term Notes	May 2052	300	5.92%
ANR PIPELINE COMPANY					
	May 2022	Senior Unsecured Notes	May 2032	US 300	3.43%
	May 2022	Senior Unsecured Notes	May 2034	US 200	3.58%
	May 2022	Senior Unsecured Notes	May 2037	US 200	3.73%
	May 2022	Senior Unsecured Notes	May 2029	US 100	3.26%

Junior subordinated notes issued

In March 2022, we issued US$800 million of junior subordinated notes through TransCanada Trust, a wholly-owned financing trust subsidiary of TCPL. We used the proceeds from the issuance to redeem all issued and outstanding TC Energy Series 15 preferred shares on May 31, 2022 pursuant to their terms. Refer to Note 9, Junior subordinated notes issued, of our Condensed consolidated financial statements for additional information.

DIVIDENDS

On July 27, 2022, we declared quarterly dividends on our common shares of $0.90 per share payable on October 31, 2022, to shareholders of record at the close of business on September 30, 2022.

DIVIDEND REINVESTMENT PLAN

To prudently fund our growth program that includes increased project costs on the NGTL System and following our commitment to make an equity contribution of $1.9 billion to Coastal GasLink LP, we have reinstated issuance of common shares from treasury at a two per cent discount under our DRP commencing with the dividends declared on July 27, 2022.

SHARE INFORMATION

At July 22, 2022, we had 984 million issued and outstanding common shares and 6 million outstanding options to buy common shares, of which 3 million were exercisable.

On May 31, 2022, we redeemed all of the 40 million issued and outstanding Series 15 preferred shares at a redemption price of $25.00 per share and paid the final quarterly dividend of $0.30625 per Series 15 preferred share for the period up to but excluding May 31, 2022, as previously announced on April 1, 2022.

CONTRACTUAL OBLIGATIONS

In 2022, capital expenditure commitments increased primarily due to an additional equity contribution expected to be made to Coastal GasLink LP of $1.9 billion as a result of the revised project agreements. Otherwise, the capital expenditure commitments are largely consistent with December 31, 2021, reflecting the net effect of normal course fulfillment of commitments related to construction, partially offset by new commitments on capital projects.

There were no material changes to our contractual obligations in second quarter 2022 or to payments due in the next five years or after. Refer to our 2021 Annual Report for more information about our contractual obligations.

Financial risks and financial instruments

We are exposed to market risk and counterparty credit risk and have strategies, policies and limits in place to manage the impact of these risks on our earnings, cash flows and, ultimately, shareholder value.

Risk management strategies, policies and limits are designed to ensure our risks and related exposures are in line with our business objectives and risk tolerance.

Refer to our 2021 Annual Report for more information about the risks we face in our business which have not changed substantially since December 31, 2021, other than as noted within this MD&A.

INTEREST RATE RISK

We utilize both short- and long-term debt to finance our operations which exposes us to interest rate risk. We typically pay fixed rates of interest on our long-term debt and floating rates on short-term debt including our commercial paper programs and amounts drawn on our credit facilities. A small portion of our long-term debt bears interest at floating rates. In addition, we are exposed to interest rate risk on financial instruments and contractual obligations containing variable interest rate components. We actively manage our interest rate risk using interest rate derivatives.

Many of our financial instruments and contractual obligations with variable rate components reference U.S. dollar London Interbank Offered Rate (LIBOR), of which certain rate settings have ceased to be published at the end of 2021 with full cessation by mid-2023. We expect to use practical expedients available in the guidance to treat contract modifications as events that do not require contract remeasurement or reassessment of previous accounting determinations. As such, these changes are not expected to have a material impact on our consolidated financial statements. In the six months ended June 30, 2022, we have not identified any applicable contract modifications as a result of reference rate reform. We continue to monitor any new developments with respect to this guidance.

On May 16, 2022, Refinitiv Benchmark Services (UK) Limited, the administrator of the Canadian Dollar Offered Rate (CDOR), announced that the calculation and publication of all tenors of CDOR will permanently cease following a final publication on June 28, 2024. We are currently evaluating the impact of this guidance on contracts and financial instruments with variable rate components that reference CDOR and have not yet determined the effect on our consolidated financial statements.

FOREIGN EXCHANGE RISK

Certain of our businesses generate all or most of their earnings in U.S. dollars and, since we report our financial results in Canadian dollars, changes in the value of the U.S. dollar against the Canadian dollar can affect our comparable EBITDA and comparable earnings. Refer to the Consolidated results – Foreign exchange section for additional information.

A small portion of our Mexico Natural Gas Pipelines monetary assets and liabilities are peso-denominated, while the functional currency for our Mexico operations is U.S. dollars. These peso-denominated balances are revalued to U.S. dollars and, as a result, changes in the value of the Mexican peso against the U.S. dollar can affect our net income. In addition, foreign exchange gains or losses calculated for Mexico income tax purposes on the revaluation of the Sur de Texas U.S. dollar-denominated loan payable to us and our partner result in peso-denominated deferred income tax expense or recovery for Sur de Texas, leading to fluctuations in comparable EBITDA. These exposures are managed using foreign exchange derivatives, with the hedging gains and losses recorded in Interest income and other.

We hedge a portion of our net investment in foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, foreign exchange forwards and foreign exchange options as appropriate.

COUNTERPARTY CREDIT RISK

We have exposure to counterparty credit risk in a number of areas including:

- cash and cash equivalents
- accounts receivable and certain contractual recoveries
- available-for-sale assets
- fair value of derivative assets
- loans receivable.

Market events causing disruptions in global energy demand and supply may contribute to economic uncertainties impacting a number of our customers. While the majority of our credit exposure is to large creditworthy entities, we maintain close monitoring and communication with those counterparties experiencing greater financial pressures. Refer to our 2021 Annual Report for more information about the factors that mitigate our counterparty credit risk exposure.

We review financial assets carried at amortized cost for impairment using the lifetime expected loss of the financial asset at initial recognition and throughout the life of the financial asset. We use historical credit loss and recovery data, adjusted for our judgment regarding current economic and credit conditions, along with supportable forecasts to determine any impairment, which is recognized in Plant operating costs and other. At June 30, 2022, we had no significant credit losses, no significant credit risk concentration and no significant amounts past due or impaired.

We have significant credit and performance exposure to financial institutions because they hold cash deposits and provide committed credit lines and letters of credit that help manage our exposure to counterparties and provide liquidity in commodity, foreign exchange and interest rate derivative markets.

LIQUIDITY RISK

Liquidity risk is the risk that we will not be able to meet our financial obligations as they come due. We manage our liquidity risk by continuously forecasting our cash flows and ensuring we have adequate cash balances, cash flows from operations, committed and demand credit facilities and access to capital markets to meet our operating, financing and capital expenditure obligations under both normal and stressed economic conditions.

RELATED PARTY TRANSACTIONS

Loans receivable from affiliates

Related party transactions are conducted in the normal course of business and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Sur de Texas

We hold a 60 per cent equity interest in a joint venture with IEnova to own the Sur de Texas pipeline, for which we are the operator. In 2017, we entered into a MXN$21.3 billion unsecured revolving credit facility with the joint venture, which bore interest at a floating rate and was fully repaid upon maturity on March 15, 2022 in the amount of approximately $1.2 billion.

Our Condensed consolidated statement of income reflected the related interest income and foreign exchange impact on this loan which were fully offset upon consolidation with corresponding amounts included in our proportionate share of Sur de Texas' equity earnings as follows:

	three months ended June 30		six months ended June 30		Affected line item in the Condensed consolidated statement of income
(millions of $)	**2022**	2021	**2022**	2021	
Interest income[1]	**—**	21	**19**	42	Interest income and other
Interest expense[2]	**—**	(21)	**(19)**	(42)	Income from equity investments
Foreign exchange gains/(losses)[1]	**—**	32	**(28)**	(3)	Interest income and other
Foreign exchange (losses)/gains[1]	**—**	(32)	**28**	3	Income from equity investments

1 Included in our Corporate segment.

2 Included in our Mexico Natural Gas Pipelines segment.

As part of refinancing activities with the Sur de Texas joint venture, on March 15, 2022, the peso-denominated loan discussed above was replaced with a new U.S. dollar-denominated loan of an equivalent $1.2 billion (US$938 million) with a floating interest rate and maturity date of March 15, 2023. At June 30, 2022, Loans receivable from affiliates under Current assets on our Condensed consolidated balance sheet reflected this $1.2 billion (US$938 million) loan receivable from the Sur de Texas joint venture.

Coastal GasLink LP

We hold a 35 per cent equity interest in Coastal GasLink LP, and have been contracted to develop and operate the Coastal GasLink pipeline.

Subordinated Demand Revolving Credit Facility

We have a subordinated demand revolving credit facility with Coastal GasLink LP to provide additional short-term liquidity and funding flexibility to the project. The facility bears interest at a floating market-based rate and had a capacity of $500 million with an outstanding balance of $1 million at June 30, 2022 (December 31, 2021 – $1 million) reflected in Loans receivable from affiliates under Current assets on our Condensed consolidated balance sheet.

Subordinated Loan Agreement

In 2021, we entered into a subordinated loan agreement with Coastal GasLink LP to provide temporary financing to fund incremental project costs as a bridge to a required increase in project-level financing. In March 2022, TC Energy increased its commitment under this subordinated loan agreement by $500 million, which brought the total capacity of this loan to $3.8 billion with an outstanding balance of $350 million as at June 30, 2022 (December 31, 2021 – $238 million) that is reflected in Long-term loans receivable from affiliate on our Condensed consolidated balance sheet. This loan balance is expected to be repaid prior to the in-service date of the pipeline.

Upon completion of and subject to definitive agreements with our equity partners, this loan agreement will be amended such that any amounts loaned to Coastal GasLink LP going forward will earn a floating market-based interest rate, which will be repaid subsequent to the in-service date of the Coastal GasLink pipeline when final costs are determined.

In accordance with a binding commitment subject to the execution of definitive agreements with our Coastal GasLink LP partners, our commitment under the amended subordinated loan agreement between TC Energy and Coastal GasLink LP will be stepped down from the current $3.8 billion over time as capacity under the project-level credit facilities is increased and we make installment payments of the $1.9 billion equity contribution we have committed to make to Coastal GasLink LP.

FINANCIAL INSTRUMENTS

With the exception of long-term debt and junior subordinated notes, our derivative and non-derivative financial instruments are recorded on the balance sheet at fair value unless they were entered into and continue to be held for the purpose of receipt or delivery in accordance with our normal purchase and sales exemptions and are documented as such. In addition, fair value accounting is not required for other financial instruments that qualify for certain accounting exemptions.

Derivative instruments

We use derivative instruments to reduce volatility associated with fluctuations in commodity prices, interest rates and foreign exchange rates. Derivative instruments, including those that qualify and are designated for hedge accounting treatment, are recorded at fair value.

The majority of derivative instruments that are not designated or do not qualify for hedge accounting treatment have been entered into as economic hedges to manage our exposure to market risk and are classified as held for trading. Changes in the fair value of held-for-trading derivative instruments are recorded in net income in the period of change. This may expose us to increased variability in reported operating results since the fair value of the held-for-trading derivative instruments can fluctuate significantly from period to period.

The recognition of gains and losses on derivatives for Canadian natural gas regulated pipeline exposures is determined through the regulatory process. Gains and losses arising from changes in the fair value of derivatives accounted for as part of RRA, including those that qualify for hedge accounting treatment, are expected to be recovered or refunded through the tolls charged by us. As a result, these gains and losses are deferred as regulatory assets or regulatory liabilities and are collected from or refunded to the ratepayers in subsequent years when the derivative settles.

Balance sheet presentation of derivative instruments

The balance sheet presentation of the fair value of derivative instruments is as follows:

(millions of $)	**June 30, 2022**	**December 31, 2021**
Other current assets	**548**	169
Other long-term assets	**58**	48
Accounts payable and other	**(694)**	(221)
Other long-term liabilities	**(55)**	(47)
	(143)	(51)

Unrealized and realized gains and losses on derivative instruments

The following summary does not include hedges of our net investment in foreign operations:

	three months ended June 30		six months ended June 30	
(millions of $)	**2022**	**2021**	**2022**	**2021**
Derivative Instruments Held for Trading[1]				
Amount of unrealized (losses)/gains in the period				
Commodities	**(20)**	(15)	**(58)**	16
Foreign exchange	**(60)**	(63)	**(38)**	(58)
Amount of realized gains/(losses) in the period				
Commodities	**255**	48	**396**	109
Foreign exchange	**(13)**	117	**28**	158
Derivative Instruments in Hedging Relationships				
Amount of realized (losses)/gains in the period				
Commodities	**(15)**	(12)	**(18)**	(23)
Interest rate	**1**	(6)	**(2)**	(12)

1 Realized and unrealized gains and losses on held-for-trading derivative instruments used to purchase and sell commodities are included on a net basis in Revenues. Realized and unrealized gains and losses on foreign exchange held-for-trading derivative instruments are included on a net basis in Interest income and other.

For further details on our non-derivative and derivative financial instruments, including classification assumptions made in the calculation of fair value and additional discussion of exposure to risks and mitigation activities, refer to Note 13, Risk management and financial instruments, of our Condensed consolidated financial statements.

Other information

CONTROLS AND PROCEDURES

Management, including our President and CEO and our CFO, evaluated the effectiveness of our disclosure controls and procedures as at June 30, 2022, as required by the Canadian securities regulatory authorities and by the SEC and concluded that our disclosure controls and procedures are effective at a reasonable assurance level.

There were no changes in second quarter 2022 that had or are likely to have a material impact on our internal control over financial reporting.

CRITICAL ACCOUNTING ESTIMATES AND ACCOUNTING POLICY CHANGES

When we prepare financial statements that conform with U.S. GAAP, we are required to make estimates and assumptions that affect the timing and amounts we record for our assets, liabilities, revenues and expenses because these items may be affected by future events. We base the estimates and assumptions on the most current information available, using our best judgment. We also regularly assess the assets and liabilities themselves. A summary of our critical accounting estimates is included in our 2021 Annual Report.

Impairment of long-lived assets and goodwill

Goodwill is tested for impairment on an annual basis, or more frequently if events or changes in circumstances indicate it might be impaired. We can initially make this assessment based on qualitative factors. If we conclude that it is more likely than not that the fair value of the reporting unit is less than its carrying value, we will then perform a quantitative goodwill impairment test.

During first quarter 2022, we elected to pursue an unanticipated opportunity to extend the existing recourse rates on Great Lakes. This prompted us to re-evaluate the impact of maintaining recourse rates at the current level as opposed to moving forward with the previously presumed Great Lakes rate case process in 2022.

On March 18, 2022, Great Lakes reached a pre-filing settlement with its customers and filed an unopposed rate case settlement with FERC by which Great Lakes and the settling parties agreed to maintain existing recourse rates through October 31, 2025. While the settlement created short-term rate certainty, it prompted a re-evaluation of Great Lakes' long-term free cash flows. With recourse rates maintained at the current level for the next three years, the expectation of increased contracting, growth and other near-term commercial and regulatory opportunities were negatively impacted.

Management performed a quantitative impairment test that evaluated a range of assumptions through a discounted cash flow analysis using a risk-adjusted discount rate. It was determined that the estimated fair value of the Great Lakes reporting unit no longer exceeded its carrying value, including goodwill, and that an impairment charge was necessary. As a result, we recorded a pre-tax goodwill impairment charge of $571 million ($531 million after tax) within the U.S. Natural Gas Pipelines segment that is included in Goodwill and asset impairment charges and other in the Condensed consolidated statement of income and was excluded from comparable earnings. The remaining goodwill balance related to Great Lakes is US$122 million at June 30, 2022 (December 31, 2021 – US$573 million). There is a risk that continued reductions in future cash flow forecasts and adverse changes in other key assumptions could result in a future impairment of the goodwill balance relating to Great Lakes.

We have elected to allocate goodwill impairment charges first to goodwill that is non-deductible for income tax purposes, with any remaining charge allocated to tax-deductible goodwill. The majority of the Great Lakes goodwill impairment charge was allocated to non-deductible goodwill and the income tax recovery of $40 million was attributable to the portion of the goodwill that was deductible for income tax purposes.

Accounting changes

Our significant accounting policies have remained unchanged since December 31, 2021 other than as described in Note 2, Accounting changes, of our Condensed consolidated financial statements. A summary of our significant accounting policies is included in our 2021 Annual Report.

Quarterly results

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

	2022		2021				2020	
(millions of $, except per share amounts)	**Second**	**First**	**Fourth**	**Third**	**Second**	**First**	**Fourth**	**Third**
Revenues	**3,637**	3,500	3,584	3,240	3,182	3,381	3,297	3,195
Net income/(loss) attributable to common shares	**889**	358	1,118	779	975	(1,057)	1,124	904
Comparable earnings	**979**	1,103	1,028	970	1,038	1,106	1,069	891
Per share statistics:								
Net income/(loss) per common share – basic	**$0.90**	$0.36	$1.14	$0.80	$1.00	($1.11)	$1.20	$0.96
Comparable earnings per common share	**$1.00**	$1.12	$1.05	$0.99	$1.06	$1.16	$1.14	$0.95
Dividends declared per common share	**$0.90**	$0.90	$0.87	$0.87	$0.87	$0.87	$0.81	$0.81

FACTORS AFFECTING QUARTERLY FINANCIAL INFORMATION BY BUSINESS SEGMENT

Quarter-over-quarter revenues and net income fluctuate for reasons that vary across our business segments.

In our Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines and Mexico Natural Gas Pipelines segments, except for seasonal fluctuations in short-term throughput volumes on U.S. pipelines, quarter-over-quarter revenues and segmented earnings generally remain relatively stable during any fiscal year. Over the long term, however, they fluctuate because of:

- regulatory decisions
- negotiated settlements with customers
- newly constructed assets being placed in service
- acquisitions and divestitures
- developments outside of the normal course of operations
- certain fair value adjustments.

In Liquids Pipelines, annual revenues and segmented earnings are based on contracted and uncontracted spot transportation, as well as liquids marketing activities. Quarter-over-quarter revenues and segmented earnings are affected by:

- regulatory decisions
- newly constructed assets being placed in service
- acquisitions and divestitures
- demand for uncontracted transportation services
- liquids marketing activities and commodity prices
- developments outside of the normal course of operations
- certain fair value adjustments.

In Power and Storage, quarter-over-quarter revenues and segmented earnings are affected by:

- weather
- customer demand
- newly constructed assets being placed in service
- acquisitions and divestitures
- market prices for natural gas and power
- capacity prices and payments
- planned and unplanned plant outages
- developments outside of the normal course of operations
- certain fair value adjustments.

FACTORS AFFECTING FINANCIAL INFORMATION BY QUARTER

We calculate comparable measures by adjusting certain GAAP and non-GAAP measures for specific items we believe are significant but not reflective of our underlying operations in the period.

We exclude from comparable measures the unrealized gains and losses from changes in the fair value of derivatives related to financial and commodity price risk management activities. These derivatives generally provide effective economic hedges but do not meet the criteria for hedge accounting. Beginning in first quarter 2022, with retroactive restatement of prior periods, we exclude from comparable measures our proportionate share of the unrealized gains and losses from changes in the fair value of Bruce Power's investments held for post-retirement benefits and derivatives related to its risk management activities. These changes in fair value are recorded in net income. As these amounts do not accurately reflect the gains and losses that will be realized at settlement, we do not consider them reflective of our underlying operations.

We also exclude from comparable measures the unrealized foreign exchange gains and losses on the peso-denominated loan receivable from an affiliate as well as the corresponding proportionate share of Sur de Texas foreign exchange gains and losses, as the amounts do not accurately reflect the gains and losses that will be realized at settlement. These amounts offset within each reporting period, resulting in no impact on net income. This peso-denominated loan was fully repaid in first quarter 2022.

In second quarter 2022, comparable earnings also excluded:

- preservation and storage costs for Keystone XL pipeline project assets of $3 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge
- a $2 million income tax expense for the settlement related to prior years' income tax assessments in Mexico.

In first quarter 2022, comparable earnings also excluded:

- an after-tax goodwill impairment charge of $531 million related to Great Lakes
- a $193 million income tax expense for the settlement-in-principle of matters related to prior years' income tax assessments in Mexico
- preservation and storage costs for Keystone XL pipeline project assets of $5 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge.

In fourth quarter 2021, comparable earnings also excluded:

- an incremental $60 million after-tax reduction to the Keystone XL asset impairment charge, net of expected contractual recoveries and other contractual and legal obligations, related to the termination of the Keystone XL pipeline project
- an after-tax gain of $19 million related to the sale of the remaining interest in Northern Courier
- preservation and storage costs for Keystone XL pipeline project assets of $10 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge
- a $7 million after-tax gain related to pension adjustments as part of the Voluntary Retirement Program (VRP)
- an incremental $6 million income tax expense related to the sale of our Ontario natural gas-fired power plants sold in 2020.

In third quarter 2021, comparable earnings also excluded:

- a $55 million after-tax expense with respect to transition payments incurred as part of the VRP
- preservation and other costs of $11 million after tax primarily related to the preservation and storage of Keystone XL pipeline project assets.

In second quarter 2021, comparable earnings also excluded:

- preservation and other costs of $16 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge and interest expense on the Keystone XL project-level credit facility prior to its termination
- a $13 million after-tax recovery of certain costs from the IESO associated with the Ontario natural gas-fired power plants sold in 2020
- an incremental $2 million after-tax asset impairment charge, net of expected contractual recoveries and other contractual and legal obligations, related to the termination of the Keystone XL pipeline project.

In first quarter 2021, comparable earnings also excluded:

- an after-tax asset impairment charge, net of expected contractual recoveries and other contractual and legal obligations, of $2.2 billion related to the formal suspension of the Keystone XL pipeline project following the January 2021 revocation of the Presidential Permit.

In fourth quarter 2020, comparable earnings also excluded:

- an incremental after-tax loss of $81 million related to the sale of our Ontario natural gas-fired power plants
- an income tax valuation allowance release of $18 million related to certain prior years' U.S. income tax losses resulting from our reassessment of deferred tax assets that are more likely than not to be realized
- an additional $18 million income tax recovery related to state income taxes on the sale of certain Columbia Midstream assets in 2019.

In third quarter 2020, comparable earnings also excluded:

- an incremental after-tax loss of $45 million related to the sale of the Ontario natural gas-fired power plants
- a $6 million reduction in the after-tax gain related to the sale of a 65 per cent equity interest in Coastal GasLink LP.

Condensed consolidated statement of income

	three months ended June 30		six months ended June 30	
(unaudited - millions of Canadian $, except per share amounts)	**2022**	2021	**2022**	2021
Revenues				
Canadian Natural Gas Pipelines	**1,175**	1,126	**2,263**	2,245
U.S. Natural Gas Pipelines	**1,397**	1,206	**2,846**	2,557
Mexico Natural Gas Pipelines	**156**	149	**308**	303
Liquids Pipelines	**692**	516	**1,360**	1,089
Power and Storage	**217**	185	**360**	369
	3,637	3,182	**7,137**	6,563
Income from Equity Investments	**236**	157	**441**	416
Operating and Other Expenses				
Plant operating costs and other	**1,173**	959	**2,179**	1,845
Commodity purchases resold	**173**	—	**301**	—
Property taxes	**213**	196	**420**	392
Depreciation and amortization	**635**	633	**1,261**	1,278
Goodwill and asset impairment charges and other	**—**	9	**571**	2,854
	2,194	1,797	**4,732**	6,369
Gain on Sale of Assets	**—**	17	**—**	17
Financial Charges				
Interest expense	**620**	583	**1,200**	1,153
Allowance for funds used during construction	**(63)**	(64)	**(138)**	(114)
Interest income and other	**43**	(127)	**(18)**	(189)
	600	392	**1,044**	850
Income/(Loss) before Income Taxes	**1,079**	1,167	**1,802**	(223)
Income Tax Expense/(Recovery)				
Current	**94**	58	**369**	267
Deferred	**54**	89	**102**	(560)
	148	147	**471**	(293)
Net Income	**931**	1,020	**1,331**	70
Net income attributable to non-controlling interests	**9**	6	**20**	75
Net Income/(Loss) Attributable to Controlling Interests	**922**	1,014	**1,311**	(5)
Preferred share dividends	**33**	39	**64**	77
Net Income/(Loss) Attributable to Common Shares	**889**	975	**1,247**	(82)
Net Income/(Loss) per Common Share				
Basic and diluted	**$0.90**	$1.00	**$1.27**	($0.08)
Weighted Average Number of Common Shares (millions)				
Basic	**983**	979	**982**	966
Diluted	**984**	979	**983**	966

See accompanying Notes to the Condensed consolidated financial statements.

Condensed consolidated statement of comprehensive income

(unaudited - millions of Canadian $)	three months ended June 30		six months ended June 30	
	2022	**2021**	**2022**	**2021**
Net Income	**931**	1,020	**1,331**	70
Other Comprehensive Income/(Loss), Net of Income Taxes				
Foreign currency translation gains and losses on net investment in foreign operations	**663**	(233)	**362**	(531)
Change in fair value of net investment hedges	**(27)**	13	**(8)**	24
Change in fair value of cash flow hedges	**(6)**	(11)	**12**	—
Reclassification to net income of gains and losses on cash flow hedges	**7**	10	**15**	18
Reclassification to net income of actuarial gains and losses on pension and other post-retirement benefit plans	**3**	4	**4**	7
Other comprehensive income/(loss) on equity investments	**165**	(57)	**345**	130
Other comprehensive income/(loss)	**805**	(274)	**730**	(352)
Comprehensive Income/(Loss)	**1,736**	746	**2,061**	(282)
Comprehensive income attributable to non-controlling interests	**13**	6	**22**	63
Comprehensive Income/(Loss) Attributable to Controlling Interests	**1,723**	740	**2,039**	(345)
Preferred share dividends	**33**	39	**64**	77
Comprehensive Income/(Loss) Attributable to Common Shares	**1,690**	701	**1,975**	(422)

See accompanying Notes to the Condensed consolidated financial statements.

Condensed consolidated statement of cash flows

	three months ended June 30		six months ended June 30	
(unaudited - millions of Canadian $)	**2022**	2021	**2022**	2021
Cash Generated from Operations				
Net income	**931**	1,020	**1,331**	70
Depreciation and amortization	**635**	633	**1,261**	1,278
Goodwill and asset impairment charges and other	**—**	9	**571**	2,854
Deferred income taxes	**54**	89	**102**	(560)
Income from equity investments	**(236)**	(157)	**(441)**	(416)
Distributions received from operating activities of equity investments	**208**	215	**442**	502
Employee post-retirement benefits funding, net of expense	**(5)**	1	**(11)**	6
Gain on sale of assets	**—**	(17)	**—**	(17)
Equity allowance for funds used during construction	**(45)**	(45)	**(98)**	(79)
Unrealized losses on financial instruments	**80**	78	**96**	42
Foreign exchange (gains)/losses on loan receivable from affiliate	**—**	(32)	**28**	3
Other	**(62)**	(56)	**(54)**	(47)
Increase in operating working capital	**(618)**	(27)	**(578)**	(259)
Net cash provided by operations	**942**	1,711	**2,649**	3,377
Investing Activities				
Capital expenditures	**(1,263)**	(1,214)	**(2,771)**	(2,859)
Contributions to equity investments	**(219)**	(225)	**(1,634)**	(465)
Keystone XL contractual recoveries	**473**	—	**473**	—
Loans to affiliate repaid/(issued), net	**51**	(220)	**(112)**	(220)
Other distributions from equity investments	**32**	—	**1,231**	—
Deferred amounts and other	**(107)**	(98)	**(53)**	(404)
Net cash used in investing activities	**(1,033)**	(1,757)	**(2,866)**	(3,948)
Financing Activities				
Notes payable (repaid)/issued, net	**(116)**	247	**214**	(2,460)
Long-term debt issued, net of issue costs	**2,510**	1,822	**2,510**	7,751
Long-term debt repaid	**—**	—	**(26)**	(980)
Junior subordinated notes issued, net of issue costs	**(3)**	(1)	**1,008**	495
Redeemable non-controlling interest repurchased	**—**	—	**—**	(633)
Dividends on common shares	**(885)**	(852)	**(1,738)**	(1,613)
Dividends on preferred shares	**(32)**	(38)	**(63)**	(77)
Distributions to non-controlling interests	**(13)**	(8)	**(23)**	(59)
Distributions on Class C Interests	**(2)**	—	**(23)**	—
Common shares issued, net of issue costs	**29**	26	**158**	60
Preferred shares redeemed	**(1,000)**	(500)	**(1,000)**	(500)
Other	**12**	(10)	**17**	(15)
Net cash provided by financing activities	**500**	686	**1,034**	1,969
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**22**	(9)	**14**	(40)
Increase in Cash and Cash Equivalents	**431**	631	**831**	1,358
Cash and Cash Equivalents				
Beginning of period	**1,073**	2,257	**673**	1,530
Cash and Cash Equivalents				
End of period	**1,504**	2,888	**1,504**	2,888

See accompanying Notes to the Condensed consolidated financial statements.

Condensed consolidated balance sheet

(unaudited - millions of Canadian $)		June 30, 2022	December 31, 2021
ASSETS			
Current Assets			
Cash and cash equivalents		**1,504**	673
Accounts receivable		**3,820**	3,092
Loans receivable from affiliates		**1,209**	1,217
Inventories		**1,045**	724
Other current assets		**1,681**	1,717
		9,259	7,423
Plant, Property and Equipment	net of accumulated depreciation of $33,281 and $31,930, respectively	**72,609**	70,182
Equity Investments		**9,324**	8,441
Long-Term Loans Receivable from Affiliate		**350**	238
Restricted Investments		**1,987**	2,182
Regulatory Assets		**1,904**	1,767
Goodwill		**12,215**	12,582
Other Long-Term Assets		**1,485**	1,403
		109,133	104,218
LIABILITIES			
Current Liabilities			
Notes payable		**5,466**	5,166
Accounts payable and other		**5,900**	5,099
Dividends payable		**896**	879
Accrued interest		**621**	577
Current portion of long-term debt		**1,599**	1,320
		14,482	13,041
Regulatory Liabilities		**4,251**	4,300
Other Long-Term Liabilities		**1,057**	1,059
Deferred Income Tax Liabilities		**6,501**	6,142
Long-Term Debt		**39,990**	37,341
Junior Subordinated Notes		**10,074**	8,939
		76,355	70,822
EQUITY			
Common shares, no par value		**26,891**	26,716
Issued and outstanding:	June 30, 2022 – 984 million shares December 31, 2021 – 981 million shares		
Preferred shares		**2,499**	3,487
Additional paid-in capital		**717**	729
Retained earnings		**3,254**	3,773
Accumulated other comprehensive loss		**(706)**	(1,434)
Controlling Interests		**32,655**	33,271
Non-Controlling Interests		**123**	125
		32,778	33,396
		109,133	104,218

Contingencies and Guarantees (Note 14)

Variable Interest Entities (Note 15)

Subsequent Events (Note 16)

See accompanying Notes to the Condensed consolidated financial statements.

Condensed consolidated statement of equity

(unaudited - millions of Canadian $)	three months ended June 30		six months ended June 30	
	2022	**2021**	**2022**	**2021**
Common Shares				
Balance at beginning of period	**26,860**	26,589	**26,716**	24,488
Shares issued:				
Exercise of stock options	**31**	29	**175**	67
Acquisition of TC PipeLines, LP, net of transaction costs	**—**	—	**—**	2,063
Balance at end of period	**26,891**	26,618	**26,891**	26,618
Preferred Shares				
Balance at beginning of period	**3,487**	3,980	**3,487**	3,980
Redemption of shares	**(988)**	(493)	**(988)**	(493)
Balance at end of period	**2,499**	3,487	**2,499**	3,487
Additional Paid-In Capital				
Balance at beginning of period	**717**	—	**729**	2
Keystone XL project-level credit facility retirement and issuance of Class C Interests	**—**	737	**—**	737
Acquisition of TC PipeLines, LP	**—**	—	**—**	(398)
Repurchase of redeemable non-controlling interest	**—**	394	**—**	394
Issuance of stock options, net of exercises	**—**	—	**(12)**	(1)
Reclassification of additional paid-in capital deficit to retained earnings	**—**	(397)	**—**	—
Balance at end of period	**717**	734	**717**	734
Retained Earnings				
Balance at beginning of period	**3,261**	3,082	**3,773**	5,367
Net income/(loss) attributable to controlling interests	**922**	1,014	**1,311**	(5)
Common share dividends	**(885)**	(852)	**(1,769)**	(1,704)
Preferred share dividends	**(32)**	(38)	**(49)**	(55)
Redemption of preferred shares	**(12)**	(7)	**(12)**	(7)
Reclassification of additional paid-in capital deficit to retained earnings	**—**	397	**—**	—
Balance at end of period	**3,254**	3,596	**3,254**	3,596
Accumulated Other Comprehensive Loss				
Balance at beginning of period	**(1,507)**	(2,152)	**(1,434)**	(2,439)
Other comprehensive income/(loss) attributable to controlling interests	**801**	(274)	**728**	(340)
Acquisition of TC PipeLines, LP	**—**	—	**—**	353
Balance at end of period	**(706)**	(2,426)	**(706)**	(2,426)
Equity Attributable to Controlling Interests	**32,655**	32,009	**32,655**	32,009
Equity Attributable to Non-Controlling Interests				
Balance at beginning of period	**124**	125	**125**	1,682
Net income attributable to non-controlling interests	**9**	6	**20**	74
Other comprehensive income/(loss) attributable to non-controlling interests	**4**	—	**2**	(12)
Distributions declared to non-controlling interests	**(14)**	(9)	**(24)**	(59)
Acquisition of TC PipeLines, LP	**—**	—	**—**	(1,563)
Balance at end of period	**123**	122	**123**	122
Total Equity	**32,778**	32,131	**32,778**	32,131

See accompanying Notes to the Condensed consolidated financial statements.

Notes to Condensed consolidated financial statements

(unaudited)

1. BASIS OF PRESENTATION

These Condensed consolidated financial statements of TC Energy Corporation (TC Energy or the Company) have been prepared by management in accordance with U.S. GAAP. The accounting policies applied are consistent with those outlined in TC Energy's annual audited Consolidated financial statements for the year ended December 31, 2021, except as described in Note 2, Accounting changes. Capitalized and abbreviated terms that are used but not otherwise defined herein are identified in the 2021 audited Consolidated financial statements included in TC Energy's 2021 Annual Report.

These Condensed consolidated financial statements reflect adjustments, all of which are normal recurring adjustments that are, in the opinion of management, necessary to reflect fairly the financial position and results of operations for the respective periods. These Condensed consolidated financial statements do not include all disclosures required in the annual financial statements and should be read in conjunction with the 2021 audited Consolidated financial statements included in TC Energy's 2021 Annual Report. Certain comparative figures have been adjusted to reflect the current period's presentation.

Earnings for interim periods may not be indicative of results for the fiscal year in certain of the Company's segments primarily due to:

- Natural gas pipelines segments – the timing of regulatory decisions and seasonal fluctuations in short-term throughput volumes on U.S. pipelines
- Liquids Pipelines – fluctuations in throughput volumes on the Keystone Pipeline System and marketing activities
- Power and Storage – the impacts of seasonal weather conditions on customer demand, market supply and prices of natural gas and power as well as maintenance outages in certain of the Company's investments in electrical power generation plants and Canadian non-regulated gas storage facilities.

Use of Estimates and Judgments

In preparing these financial statements, TC Energy is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgment in making these estimates and assumptions. In the opinion of management, these Condensed consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies included in the annual audited Consolidated financial statements for the year ended December 31, 2021, except as described in Note 2, Accounting changes.

2. ACCOUNTING CHANGES

Reference Rate Reform

In March 2020, FASB issued optional guidance with respect to the expected cessation of the U.S. dollar London Interbank Offered Rate (LIBOR), for which certain rate settings ceased to be published at the end of 2021 with full cessation by mid-2023. The guidance provides optional expedients for contracts and hedging relationships that are affected by reference rate reform if certain criteria are met. The Company expects to use practical expedients available in the guidance to treat contract modifications as events that do not require contract remeasurement or reassessment of previous accounting determinations. As such, these changes are not expected to have a material impact on the Company's consolidated financial statements.

To date, the Company has completed its analysis of contracts impacted by reference rate reform as well as the necessary system changes to facilitate the adoption of the proposed standard market reference rates. For the six months ended June 30, 2022, the Company has not identified any applicable contract modifications as a result of reference rate reform. TC Energy continues to monitor any new developments with respect to this guidance.

On May 16, 2022, Refinitiv Benchmark Services (UK) Limited, the administrator of the Canadian Dollar Offered Rate (CDOR), announced that the calculation and publication of all tenors of CDOR will permanently cease following a final publication on June 28, 2024. The Company is currently evaluating the impact of this guidance on contracts and financial instruments with variable rate components that reference CDOR and has not yet determined the effect on its consolidated financial statements.

Changes in Accounting Policies for 2022

Government Assistance

In November 2021, the FASB issued new guidance that expands annual disclosure requirements for entities that account for a transaction with a government by applying a grant or contribution accounting model by analogy to other accounting guidance. Entities are required to disclose the nature of the transactions, the related accounting policies used to account for the transactions, the effect of the transactions on an entity's financial statements and any significant terms and conditions of the transaction. This new guidance is effective for annual disclosure requirements at December 31, 2022 and can be applied either prospectively or retrospectively, with early application permitted. The Company adopted the guidance effective January 1, 2022 on a prospective basis and it did not have a material impact on the Company's consolidated financial statements.

Contract Assets and Liabilities from Contracts with Customers

In October 2021, the FASB issued new guidance that amends the accounting for contract assets and liabilities from contracts with customers acquired in a business combination. At the acquisition date, an acquirer should account for the contract assets and liabilities in accordance with guidance on revenue from contracts with customers. This new guidance is effective January 1, 2023 and is applied prospectively with early adoption permitted. Early adoption requires the application of the amendments retrospectively to all business combinations with an acquisition date in the year of early adoption. The Company elected to adopt the new guidance effective January 1, 2022 and it did not have any impact on the Company's consolidated financial statements.

3. SEGMENTED INFORMATION

three months ended June 30, 2022 (unaudited - millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Storage	Corporate[1]	Total
Revenues	1,175	1,397	156	692	217	—	3,637
Intersegment revenues	—	34	—	—	12	(46) [2]	—
	1,175	1,431	156	692	229	(46)	3,637
Income from equity investments	5	59	48	13	111	—	236
Plant operating costs and other	(423)	(456)	(14)	(171)	(145)	36 [2]	(1,173)
Commodity purchase resold	—	—	—	(163)	(10)	—	(173)
Property taxes	(76)	(106)	—	(30)	(1)	—	(213)
Depreciation and amortization	(296)	(217)	(28)	(80)	(14)	—	(635)
Segmented Earnings/(Losses)	385	711	162	261	170	(10)	1,679
Interest expense							(620)
Allowance for funds used during construction							63
Interest income and other							(43)
Income before Income Taxes							1,079
Income tax expense							(148)
Net Income							931
Net income attributable to non-controlling interests							(9)
Net Income Attributable to Controlling Interests							922
Preferred share dividends							(33)
Net Income Attributable to Common Shares							889

1 Includes intersegment eliminations.

2 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as Intersegment revenues in the segment providing the service and Plant operating costs and other in the segment receiving the service. These transactions are eliminated on consolidation. Intersegment profit is recognized when the product or service has been provided to third parties or otherwise realized.

three months ended June 30, 2021 (unaudited - millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Storage	Corporate[1]	Total
Revenues	1,126	1,206	149	516	185	—	3,182
Intersegment revenues	—	36	—	—	—	(36) [2]	—
	1,126	1,242	149	516	185	(36)	3,182
Income/(loss) from equity investments	2	51	28	18	90	(32) [3]	157
Plant operating costs and other	(369)	(327)	(13)	(169)	(113)	32 [2]	(959)
Property taxes	(75)	(91)	—	(28)	(2)	—	(196)
Depreciation and amortization	(323)	(187)	(26)	(78)	(19)	—	(633)
Asset impairment charge and other	—	—	—	(9)	—	—	(9)
Gain on sale of assets	—	—	—	—	17	—	17
Segmented Earnings/(Losses)	361	688	138	250	158	(36)	1,559
Interest expense							(583)
Allowance for funds used during construction							64
Interest income and other[3]							127
Income before Income Taxes							1,167
Income tax expense							(147)
Net Income							1,020
Net income attributable to non-controlling interests							(6)
Net Income Attributable to Controlling Interests							1,014
Preferred share dividends							(39)
Net Income Attributable to Common Shares							975

1 Includes intersegment eliminations.

2 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as Intersegment revenues in the segment providing the service and Plant operating costs and other in the segment receiving the service. These transactions are eliminated on consolidation. Intersegment profit is recognized when the product or service has been provided to third parties or otherwise realized.

3 Income/(loss) from equity investments includes the Company's proportionate share of Sur de Texas foreign exchange gains and losses on the peso-denominated loans from affiliates which are fully offset in Interest income and other by the corresponding foreign exchange losses and gains on the affiliate receivable balance. Refer to Note 7, Loans receivable from affiliates, for additional information.

six months ended June 30, 2022 (unaudited - millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Storage	Corporate[1]	Total
Revenues	2,263	2,846	308	1,360	360	—	7,137
Intersegment revenues	—	68	—	—	12	(80) [2]	—
	2,263	2,914	308	1,360	372	(80)	7,137
Income from equity investments	9	138	57	27	182	28 [3]	441
Plant operating costs and other	(796)	(823)	(27)	(344)	(262)	73 [2]	(2,179)
Commodity purchase resold	—	—	—	(291)	(10)	—	(301)
Property taxes	(151)	(209)	—	(58)	(2)	—	(420)
Depreciation and amortization	(582)	(428)	(56)	(161)	(34)	—	(1,261)
Goodwill impairment charge	—	(571)	—	—	—	—	(571)
Segmented Earnings	743	1,021	282	533	246	21	2,846
Interest expense							(1,200)
Allowance for funds used during construction							138
Interest income and other[3]							18
Income before Income Taxes							1,802
Income tax expense							(471)
Net Income							1,331
Net income attributable to non-controlling interests							(20)
Net Income Attributable to Controlling Interests							1,311
Preferred share dividends							(64)
Net Income Attributable to Common Shares							1,247

1 Includes intersegment eliminations.

2 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as Intersegment revenues in the segment providing the service and Plant operating costs and other in the segment receiving the service. These transactions are eliminated on consolidation. Intersegment profit is recognized when the product or service has been provided to third parties or otherwise realized.

3 Income from equity investments includes the Company's proportionate share of Sur de Texas foreign exchange gains and losses on the peso-denominated loans from affiliates which are fully offset in Interest income and other by the corresponding foreign exchange losses and gains on the affiliate receivable balance until March 15, 2022, when it was fully repaid upon maturity. Refer to Note 7, Loans receivable from affiliates, for additional information.

six months ended June 30, 2021 (unaudited - millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Storage	Corporate[1]	Total
Revenues	2,245	2,557	303	1,089	369	—	6,563
Intersegment revenues	—	74	—	—	13	(87) [2]	—
	2,245	2,631	303	1,089	382	(87)	6,563
Income from equity investments	4	122	66	36	185	3 [3]	416
Plant operating costs and other	(729)	(634)	(25)	(315)	(222)	80 [2]	(1,845)
Property taxes	(150)	(183)	—	(56)	(3)	—	(392)
Depreciation and amortization	(653)	(375)	(54)	(158)	(38)	—	(1,278)
Asset impairment charge and other	—	—	—	(2,854)	—	—	(2,854)
Gain on sale of assets	—	—	—	—	17	—	17
Segmented Earnings/(Losses)	717	1,561	290	(2,258)	321	(4)	627
Interest expense							(1,153)
Allowance for funds used during construction							114
Interest income and other[3]							189
Loss before Income Taxes							(223)
Income tax recovery							293
Net Income							70
Net income attributable to non-controlling interests							(75)
Net Loss Attributable to Controlling Interests							(5)
Preferred share dividends							(77)
Net Loss Attributable to Common Shares							(82)

1 Includes intersegment eliminations.
2 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as Intersegment revenues in the segment providing the service and Plant operating costs and other in the segment receiving the service. These transactions are eliminated on consolidation. Intersegment profit is recognized when the product or service has been provided to third parties or otherwise realized.
3 Income from equity investments includes the Company's proportionate share of Sur de Texas foreign exchange gains and losses on the peso-denominated loans from affiliates which are fully offset in Interest income and other by the corresponding foreign exchange losses and gains on the affiliate receivable balance. Refer to Note 7, Loans receivable from affiliates, for additional information.

Total Assets by Segment

(unaudited - millions of Canadian $)	June 30, 2022	December 31, 2021
Canadian Natural Gas Pipelines	**26,736**	25,213
U.S. Natural Gas Pipelines	**46,608**	45,502
Mexico Natural Gas Pipelines	**7,796**	7,547
Liquids Pipelines	**15,620**	14,951
Power and Storage	**6,959**	6,563
Corporate	**5,414**	4,442
	109,133	104,218

4. REVENUES

Disaggregation of Revenues

The following tables summarize total Revenues for the three and six months ended June 30, 2022 and 2021:

three months ended June 30, 2022 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Power and Storage**	**Total**
Revenues from contracts with customers						
Capacity arrangements and transportation	**1,157**	**1,034**	**148**	**464**	**—**	**2,803**
Power generation	**—**	**—**	**—**	**—**	**103**	**103**
Natural gas storage and other[1]	**18**	**366**	**8**	**2**	**139**	**533**
	1,175	**1,400**	**156**	**466**	**242**	**3,439**
Other revenues[2,3]	**—**	**(3)**	**—**	**226**	**(25)**	**198**
	1,175	**1,397**	**156**	**692**	**217**	**3,637**

1 Includes $18 million of fee revenues from an affiliate related to development and construction of the Coastal GasLink pipeline project which is 35 per cent owned by TC Energy.

2 Other revenues include income from the Company's marketing activities, financial instruments and lease arrangements. Refer to Note 13, Risk management and financial instruments, for additional information on financial instruments.

3 Includes $30 million of operating lease income.

three months ended June 30, 2021 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Power and Storage**	**Total**
Revenues from contracts with customers						
Capacity arrangements and transportation	1,103	948	141	485	—	2,677
Power generation	—	—	—	—	79	79
Natural gas storage and other[1]	23	247	8	1	82	361
	1,126	1,195	149	486	161	3,117
Other revenues[2,3]	—	11	—	30	24	65
	1,126	1,206	149	516	185	3,182

1 Includes $23 million of fee revenues from an affiliate related to development and construction of the Coastal GasLink pipeline project which is 35 per cent owned by TC Energy.

2 Other revenues include income from the Company's marketing activities, financial instruments and lease arrangements. Refer to Note 13, Risk management and financial instruments, for additional information on financial instruments.

3 Includes $32 million of operating lease income.

six months ended June 30, 2022 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Power and Storage**	**Total**
Revenues from contracts with customers						
Capacity arrangements and transportation	**2,224**	**2,231**	**293**	**973**	**—**	**5,721**
Power generation	**—**	**—**	**—**	**—**	**190**	**190**
Natural gas storage and other[1]	**39**	**623**	**15**	**3**	**205**	**885**
	2,263	**2,854**	**308**	**976**	**395**	**6,796**
Other revenues[2,3]	**—**	**(8)**	**—**	**384**	**(35)**	**341**
	2,263	**2,846**	**308**	**1,360**	**360**	**7,137**

1 Includes $39 million of fee revenues from an affiliate related to development and construction of the Coastal GasLink pipeline project which is 35 per cent owned by TC Energy.

2 Other revenues include income from the Company's marketing activities, financial instruments and lease arrangements. Refer to Note 13, Risk management and financial instruments, for additional information on financial instruments.

3 Includes $61 million of operating lease income.

six months ended June 30, 2021 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Power and Storage**	**Total**
Revenues from contracts with customers						
Capacity arrangements and transportation	2,195	2,067	287	971	—	5,520
Power generation	—	—	—	—	158	158
Natural gas storage and other[1]	50	457	16	2	158	683
	2,245	2,524	303	973	316	6,361
Other revenues[2,3]	—	33	—	116	53	202
	2,245	2,557	303	1,089	369	6,563

1 Includes $50 million of fee revenues from an affiliate related to development and construction of the Coastal GasLink pipeline project which is 35 per cent owned by TC Energy.

2 Other revenues include income from the Company's marketing activities, financial instruments and lease arrangements. Refer to Note 13, Risk management and financial instruments, for additional information on income from financial instruments.

3 Includes $64 million of operating lease income.

Contract Balances

(unaudited - millions of Canadian $)	**June 30, 2022**	**December 31, 2021**	**Affected line item on the Condensed consolidated balance sheet**
Receivables from contracts with customers	**1,627**	1,627	Accounts receivable
Contract assets	**243**	202	Other current assets
Long-term contract assets	**302**	249	Other long-term assets
Contract liabilities[1]	**91**	90	Accounts payable and other
Long-term contract liabilities	**187**	184	Other long-term liabilities

1 During the six months ended June 30, 2022, nil (2021 – $8 million) revenues were recognized that were included in contract liabilities at the beginning of the period.

Contract assets and long-term contract assets primarily relate to the Company's right to revenues for services completed but not invoiced at the reporting date on long-term committed capacity natural gas pipelines contracts. The change in contract assets is primarily related to the transfer to Accounts receivable when these rights become unconditional and the customer is invoiced, as well as the recognition of additional revenues that remain to be invoiced. Contract liabilities and long-term contract liabilities primarily relate to force majeure fixed capacity payments received on long-term capacity arrangements in Mexico.

Future Revenues from Remaining Performance Obligations

As at June 30, 2022, future revenues from long-term pipeline capacity arrangements and transportation as well as natural gas storage and other contracts extending through 2049 are approximately $25.6 billion, of which approximately $3.8 billion is expected to be recognized during the remainder of 2022.

5. GOODWILL

Goodwill is tested for impairment on an annual basis, or more frequently if events or changes in circumstances indicate it might be impaired. The Company can initially make this assessment based on qualitative factors. If the Company concludes that it is more likely than not that the fair value of the reporting unit is less than its carrying value, it will then perform a quantitative goodwill impairment test.

Great Lakes

During first quarter 2022, TC Energy elected to pursue an unanticipated opportunity to extend the existing recourse rates on Great Lakes. This prompted the Company to re-evaluate the impact of maintaining recourse rates at the current level as opposed to moving forward with the previously presumed Great Lakes rate case process in 2022.

On March 18, 2022, Great Lakes reached a pre-filing settlement with its customers and filed an unopposed rate case settlement with FERC by which Great Lakes and the settling parties agreed to maintain existing recourse rates through October 31, 2025. While the settlement created short-term rate certainty, it prompted a re-evaluation of Great Lakes' long-term free cash flows. With recourse rates maintained at the current level for the next three years, the expectation of increased contracting, growth and other near-term commercial and regulatory opportunities were negatively impacted.

Management performed a quantitative impairment test that evaluated a range of assumptions through a discounted cash flow analysis using a risk-adjusted discount rate. It was determined that the estimated fair value of the Great Lakes reporting unit no longer exceeded its carrying value, including goodwill, and that an impairment charge was necessary. As a result, the Company recorded a pre-tax goodwill impairment charge of $571 million ($531 million after tax) within the U.S. Natural Gas Pipelines segment that is included in Goodwill and asset impairment charges and other in the Company's Condensed consolidated statement of income. The remaining goodwill balance related to Great Lakes is US$122 million at June 30, 2022 (December 31, 2021 – US$573 million). There is a risk that continued reductions in future cash flow forecasts and adverse changes in other key assumptions could result in a future impairment of the goodwill balance relating to Great Lakes.

The Company has elected to allocate goodwill impairment charges first to goodwill that is non-deductible for income tax purposes, with any remaining charge allocated to tax-deductible goodwill. The majority of the Great Lakes goodwill impairment charge was allocated to non-deductible goodwill and the income tax recovery of $40 million was attributable to the portion of the goodwill that was deductible for income tax purposes.

6. INCOME TAXES

Effective Tax Rates

The effective income tax rates were 26 per cent and 132 per cent for the six months ended June 30, 2022 and 2021, respectively. The decrease in the effective income tax rate was primarily due to the impacts of the Keystone XL asset impairment charge and other recorded in 2021, partially offset by the settlement of Mexico income tax assessments discussed below and the non-tax deductible portion of the Great Lakes goodwill impairment charge recorded in the six months ended June 30, 2022.

Mexico Tax Audit

In 2019, the Mexican tax authority, the Tax Administration Services (SAT), completed an audit of the 2013 tax return of one of the Company's subsidiaries in Mexico. The audit resulted in a tax assessment that denied the deduction for all interest expense and an assessment of additional tax, penalties and financial charges totaling less than US$1 million. The Company disagreed with this assessment and commenced litigation to challenge it. In January 2022, TC Energy received the tax court's ruling on the 2013 tax return, which upheld the SAT assessment. From September 2021 to February 2022, the SAT issued assessments for tax years 2014 through 2017 which denied the deduction of all interest expense as well as assessed incremental withholding tax on the interest. These assessments totaled approximately US$490 million in income and withholding taxes, interest, penalties and other financial charges.

On April 27, 2022, TC Energy settled with the SAT on all of the above matters for the tax years 2013 through 2021. In the six months ended June 30, 2022, the Company recorded US$152 million of income tax expense (inclusive of withholding taxes, interest, penalties and other financial charges).

7. LOANS RECEIVABLE FROM AFFILIATES

Related party transactions are conducted in the normal course of business and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Sur de Texas

TC Energy holds a 60 per cent equity interest in a joint venture with IEnova to own the Sur de Texas pipeline, for which TC Energy is the operator. In 2017, TC Energy entered into a MXN$21.3 billion unsecured revolving credit facility with the joint venture, which bore interest at a floating rate and was fully repaid upon maturity on March 15, 2022 in the amount of approximately $1.2 billion.

The Company's Condensed consolidated statement of income reflected the related interest income and foreign exchange impact on this loan which were fully offset upon consolidation with corresponding amounts included in TC Energy's proportionate share of Sur de Texas' equity earnings as follows:

	three months ended June 30		six months ended June 30		Affected line item in the Condensed consolidated statement of income
(unaudited - millions of Canadian $)	2022	2021	2022	2021	
Interest income[1]	—	21	**19**	42	Interest income and other
Interest expense[2]	—	(21)	**(19)**	(42)	Income from equity investments
Foreign exchange gains/(losses)[1]	—	32	**(28)**	(3)	Interest income and other
Foreign exchange (losses)/gains[1]	—	(32)	**28**	3	Income from equity investments

1 Included in the Corporate segment.

2 Included in the Mexico Natural Gas Pipelines segment.

On March 15, 2022, as part of refinancing activities with the Sur de Texas joint venture the peso-denominated loan discussed above was replaced with a new U.S. dollar-denominated loan of an equivalent $1.2 billion (US$938 million) with a floating interest rate and maturity date of March 15, 2023. At June 30, 2022, Loans receivable from affiliates under Current assets on the Company's Condensed consolidated balance sheet reflected this $1.2 billion (US$938 million) loan receivable from the Sur de Texas joint venture.

These loans represent TC Energy's proportionate share of debt financing to the joint venture. The related repayment and issuance discussed above are included in Investing activities in the Company's Condensed consolidated statement of cash flows.

Coastal GasLink Pipeline Limited Partnership

TC Energy holds a 35 per cent equity interest in Coastal GasLink Pipeline Limited Partnership (Coastal GasLink LP), and has been contracted to develop and operate the Coastal GasLink pipeline.

Subordinated Demand Revolving Credit Facility

The Company has a subordinated demand revolving credit facility with Coastal GasLink LP to provide additional short-term liquidity and funding flexibility to the project. The facility bears interest at a floating market-based rate and had a capacity of $500 million with an outstanding balance of $1 million as at June 30, 2022 (December 31, 2021 – $1 million) reflected in Loans receivable from affiliates under Current assets on the Company's Condensed consolidated balance sheet.

Subordinated Loan Agreement

In 2021, TC Energy entered into a subordinated loan agreement with Coastal GasLink LP to provide interim temporary financing to fund incremental project costs as a bridge to a required increase in project-level financing. Under this agreement, financing was provided through a combination of interest-bearing loans subject to floating market-based interest rates and non-interest-bearing loans. The total capacity committed under this subordinated loan agreement was $3.8 billion with an outstanding balance of $350 million as at June 30, 2022 (December 31, 2021 – $238 million) that is reflected in Long-term loans receivable from affiliate on the Company’s Condensed consolidated balance sheet. Refer to Note 16, Subsequent events, for additional information on the amendments to this loan agreement.

8. LONG-TERM DEBT

Long-Term Debt Issued

Long-term debt issued by the Company in the six months ended June 30, 2022 included the following:

(unaudited - millions of Canadian $, unless otherwise noted)					
Company	**Issue date**	**Type**	**Maturity date**	**Amount**	**Interest rate**
TRANSCANADA PIPELINES LIMITED					
	May 2022	Medium Term Notes	May 2032	800	5.33%
	May 2022	Medium Term Notes	May 2026	400	4.35%
	May 2022	Medium Term Notes	May 2052	300	5.92%
ANR PIPELINE COMPANY					
	May 2022	Senior Unsecured Notes	May 2032	US 300	3.43%
	May 2022	Senior Unsecured Notes	May 2034	US 200	3.58%
	May 2022	Senior Unsecured Notes	May 2037	US 200	3.73%
	May 2022	Senior Unsecured Notes	May 2029	US 100	3.26%

Capitalized Interest

In the three and six months ended June 30, 2022, TC Energy capitalized interest related to capital projects of $4 million and $6 million, respectively (2021 – $1 million and $18 million, respectively).

9. JUNIOR SUBORDINATED NOTES ISSUED

Junior subordinated notes issued by the Company in the six months ended June 30, 2022 included the following:

(unaudited - millions of Canadian $, unless otherwise noted)					
Company	**Issue date**	**Type**	**Maturity date**	**Amount**	**Interest rate**
TransCanada PipeLines Limited	March 2022	Junior Subordinated Notes[1]	March 2082	US 800	5.85%

1 The junior subordinated notes were issued to TransCanada Trust, a financing trust subsidiary wholly owned by TCPL. While the obligations of TransCanada Trust are fully and unconditionally guaranteed by TCPL on a subordinated basis, TransCanada Trust is not consolidated in TC Energy's financial statements since TCPL does not have a variable interest in TransCanada Trust and the only substantive assets of TransCanada Trust are junior subordinated notes of TCPL.

In March 2022, TransCanada Trust (the Trust) issued US$800 million of Trust Notes – Series 2022-A to investors with a fixed interest rate of 5.60 per cent per annum for the first 10 years and resetting on the 10th anniversary and every five years thereafter. All of the proceeds of the issuance by the Trust were loaned to TCPL for US$800 million of junior subordinated notes of TCPL at an initial fixed rate of 5.85 per cent per annum, including a 0.25 per cent administration charge. The rate on the junior subordinated notes of TCPL will reset every five years commencing March 2032 until March 2052 to the then Five-Year Treasury Rate, as defined in the document governing the subordinated notes, plus 4.236 per cent per annum; from March 2052 until March 2082, the interest rate will reset to the then Five-Year Treasury Rate plus 4.986 per cent per annum. The junior subordinated notes are callable at TCPL's option at any time from December 7, 2031 to March 7, 2032 and on each interest payment and reset date thereafter at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

The junior subordinated notes are subordinated in right of payment to existing and future senior indebtedness and other obligations of TCPL.

10. COMMON SHARES AND PREFERRED SHARES

The Board of Directors of TC Energy declared quarterly dividends as follows:

	three months ended June 30		six months ended June 30	
(unaudited - Canadian $, rounded to two decimals)	**2022**	2021	**2022**	2021
per common share	**0.90**	0.87	**1.80**	1.74
per Series 1 preferred share	**0.22**	0.22	**0.43**	0.43
per Series 2 preferred share	**0.16**	0.12	**0.28**	0.25
per Series 3 preferred share	**0.11**	0.11	**0.21**	0.21
per Series 4 preferred share	**0.12**	0.08	**0.20**	0.17
per Series 5 preferred share	**0.12**	0.12	**0.24**	0.24
per Series 6 preferred share	**0.14**	0.10	**0.25**	0.20
per Series 7 preferred share	**0.24**	0.24	**0.49**	0.49
per Series 9 preferred share	**0.24**	0.24	**0.47**	0.47
per Series 11 preferred share	**0.21**	0.21	**0.21**	0.21
per Series 13 preferred share	**—**	0.34	**—**	0.34
per Series 15 preferred share	**0.31**	0.31	**0.31**	0.31

Preferred Shares

On May 31, 2022, TC Energy redeemed all 40,000,000 issued and outstanding Series 15 preferred shares at a redemption price of $25.00 per share and paid the final quarterly dividend of $0.30625 per Series 15 preferred share, for the period up to but excluding May 31, 2022. The Company used the proceeds from the March 2022 issuance of US$800 million of junior subordinated notes through the Trust to finance this preferred share redemption.

11. OTHER COMPREHENSIVE INCOME/(LOSS) AND ACCUMULATED OTHER COMPREHENSIVE LOSS

Components of other comprehensive income/(loss), including the portion attributable to non-controlling interests and related tax effects, are as follows:

three months ended June 30, 2022 (unaudited - millions of Canadian $)	**Before tax amount**	**Income tax (expense)/ recovery**	**Net of tax amount**
Foreign currency translation gains and losses on net investment in foreign operations	**633**	**30**	**663**
Change in fair value of net investment hedges	**(36)**	**9**	**(27)**
Change in fair value of cash flow hedges	**(7)**	**1**	**(6)**
Reclassification to net income of gains and losses on cash flow hedges	**9**	**(2)**	**7**
Reclassification to net income of actuarial gains and losses on pension and other post-retirement benefit plans	**3**	**—**	**3**
Other comprehensive income on equity investments	**219**	**(54)**	**165**
Other Comprehensive Income	**821**	**(16)**	**805**

three months ended June 30, 2021 (unaudited - millions of Canadian $)	**Before tax amount**	**Income tax (expense)/ recovery**	**Net of tax amount**
Foreign currency translation gains and losses on net investment in foreign operations	(231)	(2)	(233)
Change in fair value of net investment hedges	17	(4)	13
Change in fair value of cash flow hedges	(14)	3	(11)
Reclassification to net income of gains and losses on cash flow hedges	12	(2)	10
Reclassification to net income of actuarial gains and losses on pension and other post-retirement benefit plans	6	(2)	4
Other comprehensive loss on equity investments	(76)	19	(57)
Other Comprehensive Loss	(286)	12	(274)

six months ended June 30, 2022 (unaudited - millions of Canadian $)	**Before tax amount**	**Income tax (expense)/ recovery**	**Net of tax amount**
Foreign currency translation gains and losses on net investment in foreign operations	**340**	**22**	**362**
Change in fair value of net investment hedges	**(11)**	**3**	**(8)**
Change in fair value of cash flow hedges	**17**	**(5)**	**12**
Reclassification to net income of gains and losses on cash flow hedges	**24**	**(9)**	**15**
Reclassification to net income of actuarial gains and losses on pension and other post-retirement benefit plans	**5**	**(1)**	**4**
Other comprehensive income on equity investments	**459**	**(114)**	**345**
Other Comprehensive Income	**834**	**(104)**	**730**

six months ended June 30, 2021 (unaudited - millions of Canadian $)	Before tax amount	Income tax (expense)/ recovery	Net of tax amount
Foreign currency translation gains and losses on net investment in foreign operations	(519)	(12)	(531)
Change in fair value of net investment hedges	32	(8)	24
Reclassification to net income of gains and losses on cash flow hedges	23	(5)	18
Reclassification to net income of actuarial gains and losses on pension and other post-retirement benefit plans	9	(2)	7
Other comprehensive income on equity investments	173	(43)	130
Other Comprehensive Loss	(282)	(70)	(352)

The changes in AOCI by component are as follows:

three months ended June 30, 2022 (unaudited - millions of Canadian $)	Currency translation adjustments	Cash flow hedges	Pension and other post-retirement benefit plans adjustments	Equity investments	Total[1]
AOCI balance at April 1, 2022	**(1,289)**	**(86)**	**(112)**	**(20)**	**(1,507)**
Other comprehensive income/(loss) before reclassifications[2]	**632**	**(6)**	**—**	**166**	**792**
Amounts reclassified from AOCI	**—**	**7**	**3**	**(1)**	**9**
Net current period other comprehensive income	**632**	**1**	**3**	**165**	**801**
AOCI balance at June 30, 2022	**(657)**	**(85)**	**(109)**	**145**	**(706)**

1 All amounts are net of tax. Amounts in parentheses indicate losses recorded to OCI.

2 Other comprehensive income/(loss) before reclassifications on currency translation adjustments is net of a non-controlling interest gain of $4 million.

six months ended June 30, 2022 (unaudited - millions of Canadian $)	Currency translation adjustments	Cash flow hedges	Pension and other post-retirement benefit plans adjustments	Equity investments	Total[1]
AOCI balance at January 1, 2022	**(1,009)**	**(112)**	**(113)**	**(200)**	**(1,434)**
Other comprehensive income before reclassifications[2]	**352**	**12**	**—**	**347**	**711**
Amounts reclassified from AOCI[3]	**—**	**15**	**4**	**(2)**	**17**
Net current period other comprehensive income	**352**	**27**	**4**	**345**	**728**
AOCI balance at June 30, 2022	**(657)**	**(85)**	**(109)**	**145**	**(706)**

1 All amounts are net of tax. Amounts in parentheses indicate losses recorded to OCI.

2 Other comprehensive income before reclassifications on currency translation adjustments is net of a non-controlling interest gain of $2 million.

3 Losses related to cash flow hedges reported in AOCI and expected to be reclassified to net income in the next 12 months are estimated to be $38 million ($29 million, net of tax) at June 30, 2022. These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

Details about reclassifications out of AOCI into the Condensed consolidated statement of income are as follows:

(unaudited - millions of Canadian $)	three months ended June 30 2022	three months ended June 30 2021	six months ended June 30 2022	six months ended June 30 2021	Affected line item in the Condensed consolidated statement of income[1]
Cash flow hedges					
Commodities	**(5)**	(3)	**(14)**	(5)	Revenues (Power and Storage)
Interest rate	**(4)**	(9)	**(10)**	(18)	Interest expense
	(9)	(12)	**(24)**	(23)	Total before tax
	2	2	**9**	5	Income tax expense/(recovery)
	(7)	(10)	**(15)**	(18)	Net of tax
Pension and other post-retirement benefit plans					
Amortization of actuarial losses	**(3)**	(6)	**(5)**	(9)	Plant operating costs and other[2]
	—	2	**1**	2	Income tax expense/(recovery)
	(3)	(4)	**(4)**	(7)	Net of tax
Equity investments					
Equity income	**1**	(10)	**2**	(18)	Income from equity investments
	—	3	**—**	5	Income tax expense/(recovery)
	1	(7)	**2**	(13)	Net of tax

1 All amounts in parentheses indicate expenses to the Condensed consolidated statement of income.

2 These AOCI components are included in the computation of net benefit cost. Refer to Note 12, Employee post-retirement benefits, for additional information.

12. EMPLOYEE POST-RETIREMENT BENEFITS

The net benefit cost recognized for the Company's pension benefit plans and other post-retirement benefit plans is as follows:

	three months ended June 30				six months ended June 30			
	Pension benefit plans		Other post-retirement benefit plans		Pension benefit plans		Other post-retirement benefit plans	
(unaudited - millions of Canadian $)	2022	2021	2022	2021	2022	2021	2022	2021
Service cost[1]	**36**	42	**1**	2	**72**	85	**2**	3
Other components of net benefit cost[1]								
Interest cost	**31**	30	**3**	3	**62**	60	**6**	6
Expected return on plan assets	**(60)**	(59)	**(4)**	(3)	**(119)**	(117)	**(7)**	(6)
Amortization of actuarial losses	**2**	5	**1**	—	**5**	11	**1**	1
Amortization of regulatory asset	**3**	8	**1**	1	**6**	14	**1**	1
	(24)	(16)	**1**	1	**(46)**	(32)	**1**	2
Net Benefit Cost	**12**	26	**2**	3	**26**	53	**3**	5

1 Service cost and other components of net benefit cost are included in Plant operating costs and other in the Condensed consolidated statement of income.

13. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Risk Management Overview

TC Energy has exposure to market risk and counterparty credit risk, and has strategies, policies and limits in place to manage the impact of these risks on its earnings, cash flows and, ultimately, shareholder value.

Counterparty Credit Risk

TC Energy's exposure to counterparty credit risk includes its cash and cash equivalents, accounts receivable and certain contractual recoveries, available-for-sale assets, the fair value of derivative assets and loans receivable.

Market events causing disruptions in global energy demand and supply may contribute to economic uncertainties impacting a number of TC Energy's customers. While the majority of the Company's credit exposure is to large creditworthy entities, TC Energy maintains close monitoring and communication with those counterparties experiencing greater financial pressures. Refer to TC Energy's 2021 Annual Report for more information about the factors that mitigate the Company's counterparty credit risk exposure.

The Company reviews financial assets carried at amortized cost for impairment using the lifetime expected loss of the financial asset at initial recognition and throughout the life of the financial asset. TC Energy uses historical credit loss and recovery data, adjusted for management's judgment regarding current economic and credit conditions, along with supportable forecasts to determine any impairment, which is recognized in Plant operating costs and other. At June 30, 2022, there were no significant credit losses, no significant credit risk concentration and no significant amounts past due or impaired.

The Company has significant credit and performance exposure to financial institutions because they hold cash deposits and provide committed credit lines and letters of credit that help manage our exposure to counterparties and provide liquidity in commodity, foreign exchange and interest rate derivative markets.

Net Investment in Foreign Operations

The Company hedges a portion of its net investment in foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, foreign exchange forwards and foreign exchange options as appropriate.

The fair values and notional amounts for the derivatives designated as a net investment hedge were as follows:

	June 30, 2022		December 31, 2021	
(unaudited - millions of Canadian $, unless otherwise noted)	Fair value[1,2]	Notional amount	Fair value[1,2]	Notional amount
U.S. dollar foreign exchange options (maturing 2022 to 2023)	**(11)**	**US 3,800**	(4)	US 3,800
U.S. dollar cross-currency interest rate swaps (maturing 2023 to 2025)	**13**	**US 300**	23	US 400
	2	**US 4,100**	19	US 4,200

1 Fair value equals carrying value.

2 No amounts have been excluded from the assessment of hedge effectiveness.

The notional amounts and fair values of U.S. dollar-denominated debt designated as a net investment hedge were as follows:

(unaudited - millions of Canadian $, unless otherwise noted)	June 30, 2022	December 31, 2021
Notional amount	**31,400 (US 24,400)**	30,700 (US 24,200)
Fair value	**30,600 (US 23,800)**	35,500 (US 28,100)

Non-Derivative Financial Instruments

Fair value of non-derivative financial instruments

Available-for-sale assets are recorded at fair value which is calculated using quoted market prices where available. Certain non-derivative financial instruments included in Cash and cash equivalents, Accounts receivable, Loans receivable from affiliates, Other current assets, Long-term loans receivable from affiliate, Restricted investments, Other long-term assets, Notes payable, Accounts payable and other, Dividends payable, Accrued interest and Other long-term liabilities have carrying amounts that approximate their fair value due to the nature of the item or the short time to maturity. Each of these instruments are classified in Level II of the fair value hierarchy, except for the Company's LMCI equity securities which are classified in Level I.

Credit risk has been taken into consideration when calculating the fair value of non-derivative financial instruments.

Balance sheet presentation of non-derivative financial instruments

The following table details the fair value of non-derivative financial instruments, excluding those where carrying amounts approximate fair value, and would be classified in Level II of the fair value hierarchy:

	June 30, 2022		December 31, 2021	
(unaudited - millions of Canadian $)	Carrying amount	Fair value	Carrying amount	Fair value
Long-term debt, including current portion[1,2]	**(41,589)**	**(40,516)**	(38,661)	(45,615)
Junior subordinated notes	**(10,074)**	**(9,059)**	(8,939)	(9,236)
	(51,663)	**(49,575)**	(47,600)	(54,851)

1 Long-term debt is recorded at amortized cost, except for US$600 million (December 31, 2021 – nil) that is attributed to hedged risk and recorded at fair value.

2 Net income for the three and six months ended June 30, 2022 included unrealized losses of $2 million (December 31, 2021 – nil) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$600 million of long-term debt at June 30, 2022 (December 31, 2021 – nil). There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

Available-for-sale assets summary

The following tables summarize additional information about the Company's restricted investments that were classified as available-for-sale assets:

	June 30, 2022		December 31, 2021	
(unaudited - millions of Canadian $)	LMCI restricted investments	Other restricted investments[1]	LMCI restricted investments	Other restricted investments[1]
Fair values of fixed income securities[2,3]				
Maturing within 1 year	**1**	**47**	—	26
Maturing within 1-5 years	**33**	**113**	8	107
Maturing within 5-10 years	**1,080**	**—**	1,150	—
Maturing after 10 years	**72**	**—**	84	—
Fair value of equity securities[2,4]	**671**	**—**	817	—
	1,857	**160**	2,059	133

1 Other restricted investments have been set aside to fund insurance claim losses to be paid by the Company's wholly-owned captive insurance subsidiary.

2 Available-for-sale assets are recorded at fair value and included in Other current assets and Restricted investments on the Company's Condensed consolidated balance sheet.

3 Classified in Level II of the fair value hierarchy.

4 Classified in Level I of the fair value hierarchy.

(unaudited - millions of Canadian $)	June 30, 2022		June 30, 2021	
	LMCI restricted investments[1]	Other restricted investments[2]	LMCI restricted investments[1]	Other restricted investments[2]
Net unrealized (losses)/gains in the period				
three months ended	**(151)**	**(2)**	49	—
six months ended	**(300)**	**(6)**	9	(1)
Net realized losses in the period[3]				
three months ended	**(14)**	**—**	(2)	—
six months ended	**(16)**	**—**	(3)	—

1 Gains and losses arising from changes in the fair value of LMCI restricted investments impact the subsequent amounts to be collected through tolls to cover future pipeline abandonment costs. As a result, the Company records these gains and losses as regulatory assets and liabilities, respectively.

2 Losses on other restricted investments are included in Interest income and other in the Condensed consolidated statement of income.

3 Realized losses on the sale of LMCI restricted investments are determined using the average cost basis.

Derivative Instruments

Fair value of derivative instruments

The fair value of foreign exchange and interest rate derivatives has been calculated using the income approach which uses period-end market rates and applies a discounted cash flow valuation model. The fair value of commodity derivatives has been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes or other valuation techniques have been used. The fair value of options has been calculated using the Black-Scholes pricing model. Credit risk has been taken into consideration when calculating the fair value of derivative instruments. Unrealized gains and losses on derivative instruments are not necessarily representative of the amounts that will be realized on settlement.

In some cases, even though the derivatives are considered to be effective economic hedges, they do not meet the specific criteria for hedge accounting treatment or are not designated as a hedge and are accounted for at fair value with changes in fair value recorded in net income in the period of change. This may expose the Company to increased variability in reported earnings because the fair value of the derivative instruments can fluctuate significantly from period to period.

The recognition of gains and losses on derivatives for Canadian natural gas regulated pipeline exposures is determined through the regulatory process. Gains and losses arising from changes in the fair value of derivatives accounted for as part of rate-regulated accounting, including those that qualify for hedge accounting treatment, are expected to be recovered or refunded through the tolls charged by the Company. As a result, these gains and losses are deferred as regulatory assets and regulatory liabilities and are collected from or refunded to the rate payers in subsequent years when the derivative settles.

Balance sheet presentation of derivative instruments

The balance sheet classification of the fair value of derivative instruments was as follows:

at June 30, 2022 (unaudited - millions of Canadian $)	Cash flow hedges	Fair value hedges	Net investment hedges	Held for trading	Total fair value of derivative instruments[1]
Other current assets					
Commodities[2]	—	—	—	525	525
Foreign exchange	—	—	8	14	22
Interest rate	1	—	—	—	1
	1	—	8	539	548
Other long-term assets					
Commodities[2]	—	—	—	24	24
Foreign exchange	—	—	16	9	25
Interest rate	5	4	—	—	9
	5	4	16	33	58
Total Derivative Assets	6	4	24	572	606
Accounts payable and other					
Commodities[2]	(27)	—	—	(590)	(617)
Foreign exchange	—	—	(15)	(62)	(77)
	(27)	—	(15)	(652)	(694)
Other long-term liabilities					
Commodities[2]	(5)	—	—	(32)	(37)
Foreign exchange	—	—	(7)	(9)	(16)
Interest rate	—	(2)	—	—	(2)
	(5)	(2)	(7)	(41)	(55)
Total Derivative Liabilities	(32)	(2)	(22)	(693)	(749)
Total Derivatives	(26)	2	2	(121)	(143)

1 Fair value equals carrying value.

2 Includes purchases and sales of power, natural gas, liquids and emission credits.

at December 31, 2021 (unaudited - millions of Canadian $)	Cash flow hedges	Net investment hedges	Held for trading	Total fair value of derivative instruments[1]
Other current assets				
Commodities[2]	—	—	122	122
Foreign exchange	—	10	37	47
	—	10	159	169
Other long-term assets				
Commodities[2]	—	—	8	8
Foreign exchange	—	32	6	38
Interest rate	2	—	—	2
	2	32	14	48
Total Derivative Assets	2	42	173	217
Accounts payable and other				
Commodities[2]	(23)	—	(138)	(161)
Foreign exchange	—	(4)	(46)	(50)
Interest rate	(10)	—	—	(10)
	(33)	(4)	(184)	(221)
Other long-term liabilities				
Commodities[2]	(4)	—	(6)	(10)
Foreign exchange	—	(19)	(10)	(29)
Interest rate	(8)	—	—	(8)
	(12)	(19)	(16)	(47)
Total Derivative Liabilities	(45)	(23)	(200)	(268)
Total Derivatives	(43)	19	(27)	(51)

1 Fair value equals carrying value.

2 Includes purchases and sales of power, natural gas and liquids.

The majority of derivative instruments held for trading have been entered into for risk management purposes and all are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

Derivatives in fair value hedging relationships

The following table details amounts recorded on the Condensed consolidated balance sheet in relation to cumulative adjustments for fair value hedges included in the carrying amount of the hedged liabilities:

	Carrying amount		Fair value hedging adjustments[1]	
(unaudited - millions of Canadian $)	**June 30, 2022**	**December 31, 2021**	**June 30, 2022**	**December 31, 2021**
Long-term debt	**(774)**	—	**(2)**	—

1 At June 30, 2022 and December 31, 2021, adjustments for discontinued hedging relationships included in these balances were nil.

Notional and maturity summary

The maturity and notional amount or quantity outstanding related to the Company's derivative instruments excluding hedges of the net investment in foreign operations was as follows:

at June 30, 2022 (unaudited)	Power	Natural Gas	Liquids	Emission credits	Foreign exchange	Interest rate
Net sales/(purchases)[1]	**419**	**(35)**	**4**	**100**	**—**	**—**
Millions of U.S. dollars	**—**	**—**	**—**	**—**	**7,884**	**700**
Millions of Mexican pesos	**—**	**—**	**—**	**—**	**8,700**	**—**
Maturity dates	**2022-2026**	**2022-2027**	**2022-2023**	**2022**	**2022-2026**	**2025-2030**

1 Volumes for power, natural gas, liquids and emission credit derivatives are in GWh, Bcf, MMBbls and thousand metric tonnes CO_2, respectively.

at December 31, 2021 (unaudited)	Power	Natural Gas	Liquids	Foreign exchange	Interest rate
Net sales/(purchases)[1]	490	(52)	4	—	—
Millions of U.S. dollars	—	—	—	6,636	650
Millions of Mexican pesos	—	—	—	5,500	—
Maturity dates	2022-2026	2022-2027	2022	2022-2026	2024-2026

1 Volumes for power, natural gas and liquids derivatives are in GWh, Bcf and MMBbls, respectively.

Unrealized and Realized Gains and Losses on Derivative Instruments

The following summary does not include hedges of the net investment in foreign operations:

	three months ended June 30		six months ended June 30	
(unaudited - millions of Canadian $)	2022	2021	2022	2021
Derivative Instruments Held for Trading[1]				
Amount of unrealized (losses)/gains in the period				
Commodities	**(20)**	(15)	**(58)**	16
Foreign exchange	**(60)**	(63)	**(38)**	(58)
Amount of realized gains/(losses) in the period				
Commodities	**255**	48	**396**	109
Foreign exchange	**(13)**	117	**28**	158
Derivative Instruments in Hedging Relationships				
Amount of realized (losses)/gains in the period				
Commodities	**(15)**	(12)	**(18)**	(23)
Interest rate	**1**	(6)	**(2)**	(12)

1 Realized and unrealized gains and losses on held-for-trading derivative instruments used to purchase and sell commodities are included on a net basis in Revenues. Realized and unrealized gains and losses on foreign exchange held-for-trading derivative instruments are included on a net basis in Interest income and other.

Derivatives in cash flow hedging relationships

The components of OCI (Note 11) related to the change in fair value of derivatives in cash flow hedging relationships before tax and including the portion attributable to non-controlling interests were as follows:

	three months ended June 30		six months ended June 30	
(unaudited - millions of Canadian $, pre-tax)	**2022**	2021	**2022**	2021
Change in fair value of derivative instruments recognized in OCI[1]				
Commodities	**(14)**	(11)	**(19)**	(15)
Interest rate	**7**	(3)	**36**	15
	(7)	(14)	**17**	—

1 No amounts have been excluded from the assessment of hedge effectiveness. Amounts in parentheses indicate losses recorded to OCI.

Effect of fair value and cash flow hedging relationships

The following table details amounts presented in the Condensed consolidated statement of income in which the effects of fair value or cash flow hedging relationships were recorded:

	three months ended June 30		six months ended June 30	
(unaudited - millions of Canadian $)	**2022**	2021	**2022**	2021
Fair Value Hedges				
Interest rate contracts[1]				
Hedged items	**(2)**	—	**(2)**	—
Derivatives designated as hedging instruments	**1**	—	**1**	—
Cash Flow Hedges				
Reclassification of losses on derivative instruments from AOCI to Net income[2,3]				
Commodities[4]	**(5)**	(3)	**(14)**	(5)
Interest rate[1]	**(4)**	(9)	**(10)**	(18)

1 Presented within Interest expense in the Condensed consolidated statement of income.

2 Refer to Note 11, Other comprehensive income/(loss) and accumulated other comprehensive loss, for the components of OCI related to derivatives in cash flow hedging relationships.

3 There are no amounts recognized in earnings that were excluded from effectiveness testing.

4 Presented within Revenues (Power and Storage) in the Condensed consolidated statement of income.

Offsetting of derivative instruments

The Company enters into derivative contracts with the right to offset in the normal course of business as well as in the event of default. TC Energy has no master netting agreements, however, similar contracts are entered into containing rights to offset. The Company has elected to present the fair value of derivative instruments with the right to offset on a gross basis on the Condensed consolidated balance sheet. The following table shows the impact on the presentation of the fair value of derivative instrument assets and liabilities had the Company elected to present these contracts on a net basis:

at June 30, 2022 (unaudited - millions of Canadian $)	**Gross derivative instruments**	**Amounts available for offset**[1]	**Net amounts**
Derivative instrument assets			
Commodities	**549**	**(494)**	**55**
Foreign exchange	**47**	**(41)**	**6**
Interest rate	**10**	**—**	**10**
	606	**(535)**	**71**
Derivative instrument liabilities			
Commodities	**(654)**	**494**	**(160)**
Foreign exchange	**(93)**	**41**	**(52)**
Interest rate	**(2)**	**—**	**(2)**
	(749)	**535**	**(214)**

1 Amounts available for offset do not include cash collateral pledged or received.

at December 31, 2021 (unaudited - millions of Canadian $)	**Gross derivative instruments**	**Amounts available for offset**[1]	**Net amounts**
Derivative instrument assets			
Commodities	130	(91)	39
Foreign exchange	85	(54)	31
Interest rate	2	(1)	1
	217	(146)	71
Derivative instrument liabilities			
Commodities	(171)	91	(80)
Foreign exchange	(79)	54	(25)
Interest rate	(18)	1	(17)
	(268)	146	(122)

1 Amounts available for offset do not include cash collateral pledged or received.

With respect to the derivative instruments presented above, the Company provided cash collateral of $164 million and letters of credit of $71 million at June 30, 2022 (December 31, 2021 – $144 million and $130 million, respectively) to its counterparties. At June 30, 2022, the Company held no cash collateral and an $11 million balance in letters of credit (December 31, 2021 – nil and $6 million, respectively) from counterparties on asset exposures.

Credit-risk-related contingent features of derivative instruments

Derivative contracts entered into to manage market risk often contain financial assurance provisions that allow parties to the contracts to manage credit risk. These provisions may require collateral to be provided if a credit-risk-related contingent event occurs, such as a downgrade in the Company's credit rating to non-investment grade. The Company may also need to provide collateral if the fair value of its derivative financial instruments exceeds pre-defined exposure limits.

Based on contracts in place and market prices at June 30, 2022, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $15 million (December 31, 2021 – $5 million), for which the Company has provided no collateral in the normal course of business. If the credit-risk-related contingent features in these agreements were triggered on June 30, 2022, the Company would have been required to provide collateral equal to the fair value of the related derivative instruments discussed above. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds.

The Company has sufficient liquidity in the form of cash and undrawn committed revolving credit facilities to meet these contingent obligations should they arise.

Fair Value Hierarchy

The Company's financial assets and liabilities recorded at fair value have been categorized into three categories based on a fair value hierarchy.

Levels	How fair value has been determined
Level I	Quoted prices in active markets for identical assets and liabilities that the Company has the ability to access at the measurement date. An active market is a market in which frequency and volume of transactions provides pricing information on an ongoing basis.
Level II	This category includes interest rate and foreign exchange derivative assets and liabilities where fair value is determined using the income approach and commodity derivatives where fair value is determined using the market approach. Inputs include published exchange rates, interest rates, interest rate swap curves, yield curves and broker quotes from external data service providers.
Level III	This category includes long-dated commodity transactions in certain markets where liquidity is low and the Company uses the most observable inputs available or, if not available, long-term broker quotes to estimate the fair value for these transactions. There is uncertainty caused by using unobservable market data which may not accurately reflect possible future changes in fair value.

The fair value of the Company's derivative assets and liabilities measured on a recurring basis, including both current and non-current portions, were categorized as follows:

at June 30, 2022 (unaudited - millions of Canadian $)	Quoted prices in active markets (Level I)	Significant other observable inputs (Level II)[1]	Significant unobservable inputs (Level III)[1]	Total
Derivative instrument assets				
Commodities	**435**	**114**	**—**	**549**
Foreign exchange	**—**	**47**	**—**	**47**
Interest rate	**—**	**10**	**—**	**10**
Derivative instrument liabilities				
Commodities	**(488)**	**(151)**	**(15)**	**(654)**
Foreign exchange	**—**	**(93)**	**—**	**(93)**
Interest rate	**—**	**(2)**	**—**	**(2)**
	(53)	**(75)**	**(15)**	**(143)**

1 There were no transfers from Level II to Level III for the six months ended June 30, 2022.

at December 31, 2021 (unaudited - millions of Canadian $)	Quoted prices in active markets (Level I)	Significant other observable inputs (Level II)[1]	Significant unobservable inputs (Level III)[1]	Total
Derivative instrument assets				
Commodities	39	91	—	130
Foreign exchange	—	85	—	85
Interest rate	—	2	—	2
Derivative instrument liabilities				
Commodities	(49)	(116)	(6)	(171)
Foreign exchange	—	(79)	—	(79)
Interest rate	—	(18)	—	(18)
	(10)	(35)	(6)	(51)

1 There were no transfers from Level II to Level III for the year ended December 31, 2021.

The following table presents the net change in fair value of derivative assets and liabilities classified as Level III of the fair value hierarchy:

	three months ended June 30		six months ended June 30	
(unaudited - millions of Canadian $)	**2022**	2021	**2022**	2021
Balance at beginning of period	**(12)**	(4)	**(6)**	(4)
Net losses included in Net income	**(2)**	(1)	**(8)**	(1)
Net losses included in OCI	**(1)**	—	**(1)**	—
Balance at End of Period[1]	**(15)**	(5)	**(15)**	(5)

1 For the three and six months ended June 30, 2022, there were unrealized losses of $2 million and $8 million, recognized in Revenues attributed to derivatives in the Level III category that were held at June 30, 2022 (2021 – unrealized losses of $1 million and $1 million, respectively).

14. CONTINGENCIES AND GUARANTEES

Contingencies

TC Energy and its subsidiaries are subject to various legal proceedings, arbitrations and actions arising in the normal course of business. While the final outcome of such legal proceedings and actions cannot be predicted with certainty, it is the opinion of management that the resolution of such normal course proceedings and actions will not have a material impact on the Company's consolidated financial position or results of operations.

Guarantees

TC Energy and its partner on the Sur de Texas pipeline, IEnova, have jointly guaranteed the financial performance of the entity which owns the pipeline. Such agreements include a guarantee and a letter of credit which are primarily related to the delivery of natural gas.

TC Energy and its joint venture partner on Bruce Power, BPC Generation Infrastructure Trust, have each severally guaranteed certain contingent financial obligations of Bruce Power related to a lease agreement and contractor and supplier services.

The Company and its partners in certain other jointly-owned entities have either (i) jointly and severally, (ii) jointly or (iii) severally guaranteed the financial performance of these entities. Such agreements include guarantees and letters of credit which are primarily related to construction services and the payment of liabilities. For certain of these entities, any payments made by TC Energy under these guarantees in excess of its ownership interest are to be reimbursed by its partners.

The carrying value of these guarantees has been included in Other long-term liabilities on the Condensed consolidated balance sheet. Information regarding the Company's guarantees is as follows:

		June 30, 2022		December 31, 2021	
(unaudited - millions of Canadian $)	Term	Potential exposure[1]	Carrying value	Potential exposure[1]	Carrying value
Sur de Texas	to 2043	**95**	**—**	93	—
Bruce Power	to 2023	**88**	**—**	88	—
Other jointly-owned entities	to 2043	**80**	**3**	80	4
		263	**3**	261	4

1 TC Energy's share of the potential estimated current or contingent exposure.

15. VARIABLE INTEREST ENTITIES

Consolidated VIEs

The Company's consolidated VIEs consist of legal entities where the Company is the primary beneficiary. As the primary beneficiary, the Company has the power, through voting or similar rights, to direct the activities of the VIE that most significantly impact economic performance including purchasing or selling significant assets; maintenance and operations of assets; incurring additional indebtedness; or determining the strategic operating direction of the entity. In addition, the Company has the obligation to absorb losses or the right to receive benefits from the consolidated VIE that could potentially be significant to the VIE.

A significant portion of the Company's assets are held through VIEs in which the Company holds a 100 per cent voting interest, the VIE meets the definition of a business and the VIE's assets can be used for general corporate purposes. The consolidated VIEs whose assets cannot be used for purposes other than the settlement of the VIE's obligations, or are not considered a business, are as follows:

(unaudited - millions of Canadian $)	June 30, 2022	December 31, 2021
ASSETS		
Current Assets		
Cash and cash equivalents	**65**	72
Accounts receivable	**71**	70
Inventories	**28**	28
Other current assets	**9**	13
	173	183
Plant, Property and Equipment	**3,758**	3,672
Equity Investments	**900**	890
Goodwill	**427**	421
	5,258	5,166
LIABILITIES		
Current Liabilities		
Accounts payable and other	**241**	232
Accrued interest	**17**	17
Current portion of long-term debt	**30**	29
	288	278
Regulatory Liabilities	**71**	66
Other Long-Term Liabilities	**—**	1
Deferred Income Tax Liabilities	**13**	13
Long-Term Debt	**2,033**	2,025
	2,405	2,383

Non-Consolidated VIEs

The Company's non-consolidated VIEs consist of legal entities where the Company is not the primary beneficiary as it does not have the power to direct the activities that most significantly impact the economic performance of these VIEs or where this power is shared with third parties. The Company contributes capital to these VIEs and receives ownership interests that provide it with residual claims on assets after liabilities are paid.

The carrying value of these VIEs and the maximum exposure to loss as a result of the Company's involvement with these VIEs are as follows:

(unaudited - millions of Canadian $)	June 30, 2022	December 31, 2021
Balance Sheet Exposure		
Loan receivable from affiliate[1]	**1**	1
Equity investments		
Bruce Power	**4,757**	4,493
Pipeline equity investments	**2,135**	1,605
Long-term loans receivable from affiliate[1]	**350**	238
Off-Balance Sheet Exposure[2]		
Coastal GasLink[3]	**3,425**	3,037
Bruce Power[4]	**2,249**	974
Pipeline equity investments	**98**	171
Maximum Exposure to Loss	**13,015**	10,519

1 Refer to Note 7, Loans receivable from affiliates, for additional information.

2 Includes maximum potential exposure to guarantees and future funding commitments.

3 Represents the total capacity of $3,775 million committed under a subordinated loan agreement with Coastal GasLink LP less the $350 million balance outstanding under this loan agreement as at June 30, 2022 (December 31, 2021 – $3,275 million and $238 million, respectively). Refer to Note 7, Loans receivable from affiliates, and Note 16, Subsequent events, for additional information.

4 On March 7, 2022, the IESO verified Bruce Power's Unit 3 MCR program final cost and schedule duration estimate submitted in December 2021. As at June 30, 2022, the maximum exposure includes TC Energy's portion of capital to be invested under the Unit 3 MCR program as well as the expected increase in the capital to be invested under the Asset Management program through 2027.

16. SUBSEQUENT EVENTS

Coastal GasLink LP

Settlement Agreement with LNG Canada

Coastal GasLink LP and LNG Canada have reached a settlement that addresses and resolves disputes over certain incurred and anticipated costs of the Coastal GasLink pipeline project. Capital costs have increased from the original project cost estimate due to scope increases and the impacts of COVID-19, weather and other events outside of Coastal GasLink LP's control. The revised project agreements incorporate a new cost estimate. Following execution of these revised project agreements with LNG Canada, the Coastal GasLink LP project-level credit facilities will be increased.

TC Energy Equity Contributions and Subordinated Loan Agreement

In accordance with a binding commitment subject to the execution of definitive agreements with the Coastal GasLink LP partners, TC Energy will make an equity contribution to Coastal GasLink LP of $1.9 billion, which will be paid in installments commencing in August 2022, with no resulting change to its 35 per cent ownership.

In 2021, TC Energy entered into a subordinated loan agreement with Coastal GasLink LP to provide interim temporary financing to fund incremental project costs. Total capacity of this loan was $3.8 billion with an outstanding balance of $350 million as at June 30, 2022. The balance outstanding on this loan as at June 30, 2022 is expected to be repaid prior to the in-service date of the pipeline. In accordance with a binding commitment subject to the execution of definitive agreements with the Coastal GasLink LP partners, following amendments to this loan agreement, financing available to Coastal GasLink LP going forward will be provided through an interest-bearing loan, subject to a floating market-based interest rate, which will be repaid subsequent to the in-service date of the Coastal GasLink pipeline when final costs are determined.

Dividend Reinvestment Plan

TC Energy has reinstated issuance of common shares from treasury at a two per cent discount under its Dividend Reinvestment Plan commencing with the dividends declared on July 27, 2022.