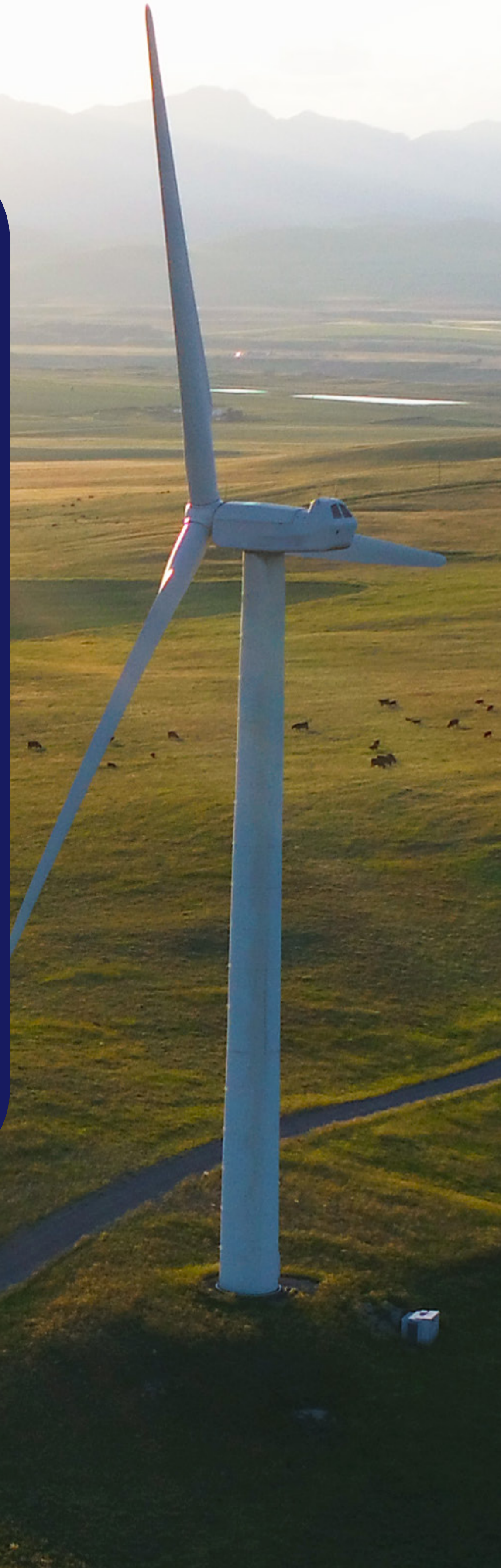
transalta™

2023 Integrated Report

Energizing the Future.

Contents



Letter from the President and CEO

John H. Kousinioris
President and Chief Executive Officer

Dear Fellow Shareholders,

Across our sector, 2023 was marked by significant challenges, ranging from increasing geopolitical risks, high inflation and rising equipment and capital costs, to financial setbacks with key equipment suppliers and industry participants. In this environment, our industry is demanding higher returns for projects to better compensate for the considerable inherent risks of investments. While the transition to clean energy will have challenges, it represents a significant opportunity for a highly capable, experienced and flexible company like ours to deliver growth and innovate in navigating the path forward. The past year brought to the forefront the "trilemma of transition" confronting the global power sector. At TransAlta, we refer to this as the three-legged stool of transition. In order to be successful, decarbonization efforts need to balance affordability, reliability as well as the reduction of emissions. All three elements need to be prudently managed to successfully advance and pursue the transition that is required to meet the challenges of climate change.

Continuing Exceptional Business Performance

Despite the challenging landscape experienced in 2023, it was another exceptional year of performance for TransAlta. We generated record results for the third year in a row, with revenues of $3.4 billion and adjusted EBITDA of $1.6 billion, in line with our adjusted EBITDA record of last year. We also delivered record net earnings to shareholders of $644 million, a $640 million increase from 2022.

On a free cash flow basis, we generated $890 million or an impressive $3.22 per share. We exceeded our guidance expectations for free cash flow, and we increased our quarterly common share dividend by nine per cent, which represents our fifth consecutive annual dividend increase. I am proud to say since 2021 that we have generated an exceptional $8.93 per share of free cash flow.

In addition to distributing dividends, we also returned $87 million to shareholders in 2023 through share repurchases. We will continue to use share repurchases as part of our capital allocation strategy, which continues to be dynamic with the changing market landscape and the readiness and timing of our growth opportunities. It is my view that our strong free cash flow results and expectations for 2024 are not appropriately reflected in the current trading price of our common shares. We have an evergreen normal course issuer bid in place that we have actively used over the past several years, and we expect to continue making accretive share buy backs at this price level.

Our increased common share dividend of $0.24 per common share, combined with our current intentions around share repurchases, would see up to approximately 40 per cent of our expected 2024 free cash flow returned to shareholders.

Our Growth team advanced 678 MW of construction projects in 2023. We achieved commercial operation at the 130 MW Garden Plain wind facility in Alberta and the 48 MW Northern Goldfields combined solar and battery storage facilities in Australia. As for our remaining construction projects, we expect the 300 MW White Rock facilities, the 200 MW Horizon Hill facility and the Mount Keith Transmission Expansion to achieve commercial operation by the end of the first quarter. Together these facilities, along with the fully rehabilitated Kent Hills facilities, are expected to contribute over $175 million in EBITDA annually.

Finally, I am pleased to say that 2023 was also a record year for our safety performance. We operated without any lost time injuries across our global operations and delivered a Total Recordable Injury Frequency rate of 0.30, an outstanding result that improved upon our previous best outcome of 0.39, which was achieved in 2022. Availability was also excellent across our facilities, at 88.8 per cent fleet-wide in 2023.

Delivered Structural Simplification and Strategic Acquisitions

In 2023, we took two key strategic steps forward with the acquisitions of TransAlta Renewables and Heartland Generation.

The acquisition of TransAlta Renewables represented a key milestone for us. It allowed us to simplify our corporate structure, unify our capital structure and add a net economic interest in 1.2 GW of generating capacity to our fleet. The transaction enables us to move forward with a simplified and unified strategy, positioning us well for future success.

We also announced an agreement to acquire Heartland Generation and its entire business operations, representing approximately 1.8 GW of generation in Alberta and British Columbia. This acquisition, which remains subject to regulatory approval, will add highly flexible and complementary natural gas assets to our Alberta portfolio. As the energy transition continues to drive new investment in renewables, there will also be an increasing need for low-cost, highly flexible and fast-responding generation to support grid reliability. The Heartland acquisition supports the competitive positioning of our fleet to meet current and future demand for reliable electricity with a robust and diversified portfolio, while being aligned with our longer-term emissions reduction commitments. Our commitment to decarbonization remains unchanged.

Global Leader in Carbon Reductions

We are proud of our decarbonization efforts and are on track to meet our target of reducing our scope 1 and 2 greenhouse gas emissions by 75 per cent below 2015 levels by 2026. We have retired 4,664 MW of coal-fired generation capacity since 2018 while converting 1,659 MW of coal-fired capacity to natural-gas-fired generation. Comparatively, our converted natural gas units' CO2 intensity is approximately 57 per cent lower than coal generation. Since 2015, we have reduced scope 1 and 2 greenhouse gas emissions by 21.3 MT CO_2e or 66 per cent, which is an incredible achievement for our fleet.

Prudent Capital Allocation and Investment Discipline

We remain focused on maintaining a balanced, prudent and disciplined approach to capital allocation with the aim of generating value for our shareholders. We continue to view investments in contracted clean energy assets, and strategic gas assets, as providing meaningful long-term shareholder value. We see many opportunities to deploy capital into higher-returning, longer-life assets, and we are focusing our efforts on capturing those opportunities over the next few years.

The path to the energy transition presents tremendous opportunities for our company given our skill set, competitive advantages and market positioning – opportunities that we are uniquely positioned to capture in each of our core markets of Canada, the United States and Australia.

At our Investor Day, we provided an update to our Clean Electricity Growth Plan goals that laid out a plan to add up to 1.75 GW of additional clean electricity over the next five years, by deploying approximately $3.5 billion of growth capital, for which we have a fully funded plan, to achieve an annual EBITDA contribution of approximately $350 million.

Although we continue to advance a number of projects toward final investment decisions, we will remain disciplined in our investment decisions to ensure we obtain appropriate risk-adjusted returns for our shareholders. Securing, acquiring and developing great projects is challenging and it is critical that we meet or exceed our targeted rates of return when we deploy our growth capital for the benefit of our shareholders. Our Clean Electricity Growth Plan is an aspirational one. We will not grow simply for the sake of growth or to meet targets.

Long-term shareholder value creation will ultimately drive our investment and capital allocation decisions. Our goal is to enhance shareholder returns, and we will look to enhance shareholder returns through our dividend and share repurchases, particularly given the current trading price of our common shares, which we consider to be undervalued.

Clean Electricity Growth Plan to 2028

As we execute our plan, we expect that approximately 70 per cent of our adjusted EBITDA will be sourced from clean generation by the end of 2028 – an amount significantly higher than the approximately 40 per cent that we have today. And, as we make the shift, TransAlta will be greener, more contracted and more diversified.

We see abundant opportunities for the company as the world increasingly electrifies to meet its growth and climate change goals. We are in a great position to succeed over the balance of the decade and beyond, with considerable optionality in our generating base and growth pipeline, coupled with our strong balance sheet and excellent financial outlook.

We see robust demand for renewable energy as corporate and government sustainability commitments remain firm. Power purchase agreement prices are responding to reflect supply and input cost pressures. We continue to strengthen our development capabilities and competitive advantages. In 2023, we combined our growth and energy marketing teams under a single leader while maintaining focus on our customer advantages in customer delivery, project development marketing, financing and operational optimization.

Preparing for 2024 and Beyond

At TransAlta, we have been working hard to set ourselves up to meet the needs of a responsible transition. We retain a cost-effective legacy fleet to maintain affordability, and we are investing in a diversified, flexible and responsive generating fleet to meet future system reliability requirements. We are also making investments in zero-carbon generation and new technologies, while relying less on our merchant gas generation to further our decarbonization objectives. As we transition our fleet towards a greener and more contracted asset base, our business risk profile will reduce and provide a positive catalyst to a multiple rerate.

In 2024, I will be focusing my efforts on our capital allocation strategy and ensuring that we return value to our shareholders through share repurchases and dividends, while also pursuing growth opportunities with appropriate returns without compromising our balance sheet strength and resilience.

Our continuing strong free cash flow will permit us to fund returns to shareholders and transition TransAlta to a higher proportion of contracted clean generation. Our portfolio continues to perform and is expected to generate approximately $1.70 per share of free cash flow in 2024, contributing to our balanced approach. In 2024, we expect to return up to 40 per cent of free cash flow to our shareholders through share repurchases and dividends. We also remain focused on identifying the opportunities and challenges that will push our company forward in the second half of the decade and into the 2030s.

Our achievements in 2023 would not have been possible without the collective contributions of all of our employees. It has been an honour to lead our talented team of committed, driven and skilled employees who embody our core values of safety, innovation, sustainability, respect, and integrity. I thank our employees for all that they do to ensure that we are powering and empowering our economies and communities sustainably.

I would also like to express my thanks to our Board of Directors for the support, guidance and wisdom that they provide day after day to our company.

We are grateful for the support and confidence of our shareholders. We greatly value your opinions and put your interests at the centre of our continued transformation and the development of our strategy.

Finally, we sincerely appreciate the support of all of our stakeholders.

I am confident in the future and believe our success will continue in 2024 and beyond.

John H. Kousinioris
President and Chief Executive Officer
February 22, 2024

Message from the Chairman of the Board

John P. Dielwart
Chair of the Board of Directors

Dear Fellow Shareholders,

As we report the financial results for the year ended December 31, 2023, I cannot overstate the pride I have in the accomplishments of all of TransAlta's employees. The Company, under direction from the Board, simplified TransAlta's structure with the acquisition of TransAlta Renewables, expanded its renewable portfolio with the commercial operation of our Garden Plain and Northern Goldfields facilities, and solidified its Alberta strategy through the announced acquisition of Heartland Generation.

The Company continues to manage its evolution for the benefit of our shareholders. We have reported another year of superior results that went well beyond the original expectations we had at the beginning of 2023. Our management team delivered another year of exceptional free cash flow for our shareholders, achieved record-setting safety results, continued to reduce our emissions ahead of targets and deployed our capital in a disciplined and prudent way throughout the year. TransAlta has delivered performance at all levels: financial, operational, safety and sustainability.

The Company's evolving strategy continues to provide exceptional results and 2023's record-setting performance reflect the success of that execution. We continue to transition the company through our Clean Electricity Growth Plan and are well-positioned as a credible and sought-after developer of choice for customers in all three core geographies in which we operate.

We announced ambitious growth targets at our recent Investor Day that would see our company transition over time to one that has 70 per cent of its adjusted EBITDA clean and contracted. Our strategy is directed towards achieving material growth in our portfolio by 2028. However, growth is challenging and it is not easy to develop projects to deliver the targeted rates of return we have set for the deployment of our capital. As a result, we will remain disciplined in the deployment of our capital and we will not grow for the sake of growth even if it means we do not achieve our 2028 targets. Creating shareholder value trumps growth. We will maintain discipline as we consider our growth aspirations and rates of return for growth projects. Acquisitions must also meet our target thresholds for value creation. Long-term shareholder value creation will drive our investment decisions and we remain committed to our prudent capital allocation approach. To the extent we deploy reduced growth capital, we will pursue enhanced shareholder returns through dividends (base and/or special) and share repurchases.

The Board would like to express our gratitude to the employees and capable leadership of TransAlta for their significant efforts in delivering another great year for the Company. The team has adapted to changing market conditions and will seek to add value to the Company in a disciplined and prudent way while being extremely mindful of capital allocation discipline and the creation of shareholder value.

We also send special thanks to all of our shareholders for their ongoing commitment to the Company and for their continued engagement. As fellow shareholders, we look forward to TransAlta's execution in 2024 and we value your engagement and viewpoints on our evolving strategy.

The Board of Directors will strive to increase shareholder value through continuous engagement with the management team to assess new opportunities that will add value to the Company and improve performance.

Finally, on behalf of the Board of Directors, I would like to extend my deep gratitude to the Honourable Rona Ambrose for her service to the Company. She has announced that she will not stand for re-election and will retire from the Board following the annual shareholders' meeting on April 25, 2024. She has been a valuable contributor to our Board since 2017 and we thank her for her leadership and insights during her tenure, especially as the Chair of the Governance, Safety and Sustainability Committee of the Board.

John Dielwart

John P. Dielwart
Chair of the Board of Directors
February 22, 2024

Who We Are

TransAlta owns, operates and develops a diverse fleet of electrical power generation assets in Canada, the United States and Australia with a focus on long-term shareholder value.

A leader in clean electricity committed to a sustainable future and a responsible energy transition

Our Mission

Provide safe, low-cost and reliable clean electricity

Our Values

- Safety
- Innovation
- Sustainability
- Respect
- Integrity

TransAlta at a Glance

TransAlta provides municipalities, medium and large industries, businesses and utility customers with clean, affordable, energy efficient and reliable power. Today, TransAlta is one of Canada's largest producers of wind power and Alberta's largest producer of hydro-electric power. For over 112 years, TransAlta has been a responsible operator and a proud member of the communities where we operate and where our employees work and live.

~5.3 GW

Development Pipeline
High-quality, diverse projects across Canada, the United States and Australia

112 years

Generation Experience
The foundation of our focused strategy

66%

Reduction in emissions
Since 2015

~1,260

Employees
Central to value creation

6,400 MW

Portfolio
A highly diversified portfolio of high-quality assets.

76

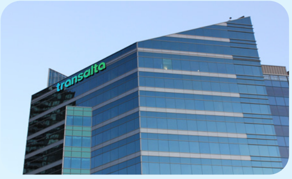
Generating Facilities
In Canada, the United States and Australia

Overview

Wind and Solar

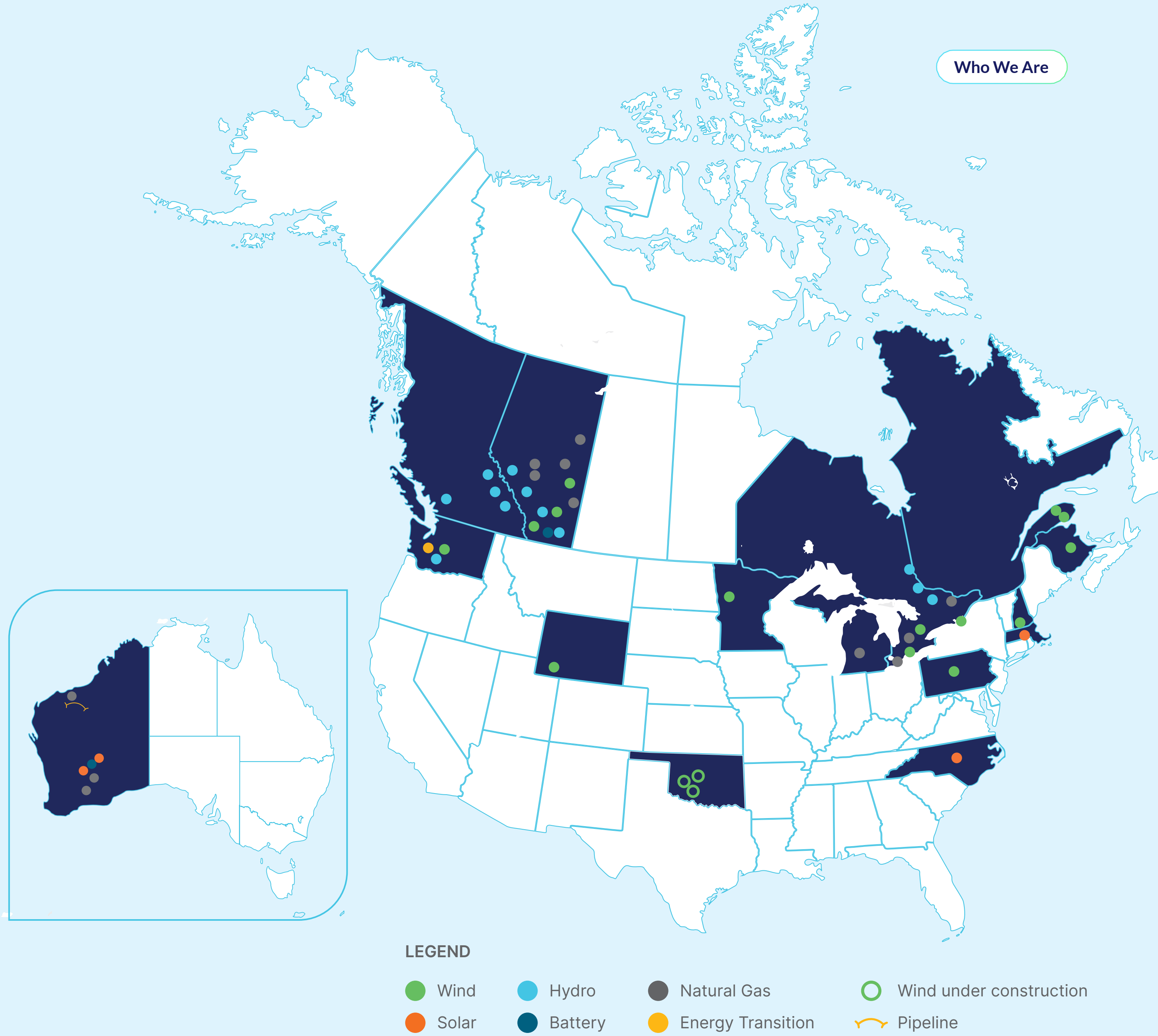
Hydro

Natural Gas



Energy Marketing

Development Pipeline and Capabilities



Australia

TransAlta Energy Australia is building on our over 25-year history in the country with significant new investments made over the past several years.

1996
First facility commissioned

498 MW
Gross installed capacity

9 Facilities
Currently operating

Canada

We began in Alberta over 112 years ago with the construction of our first hydro facility. Today, our operations span the country, providing the electricity Canadians need every day.

1911
First plant commissioned

5,044 MW
Gross installed capacity

57 Facilities
Currently operating

United States

Our United States operations began in Centralia, Washington. Since then, our US fleet has expanded to include gas, hydro, solar and wind generation.

2000
First facility acquired

1,219 MW
Gross installed capacity

10 Facilities
Currently operating

Who We Are

Development Pipeline

Early and Advanced Stage

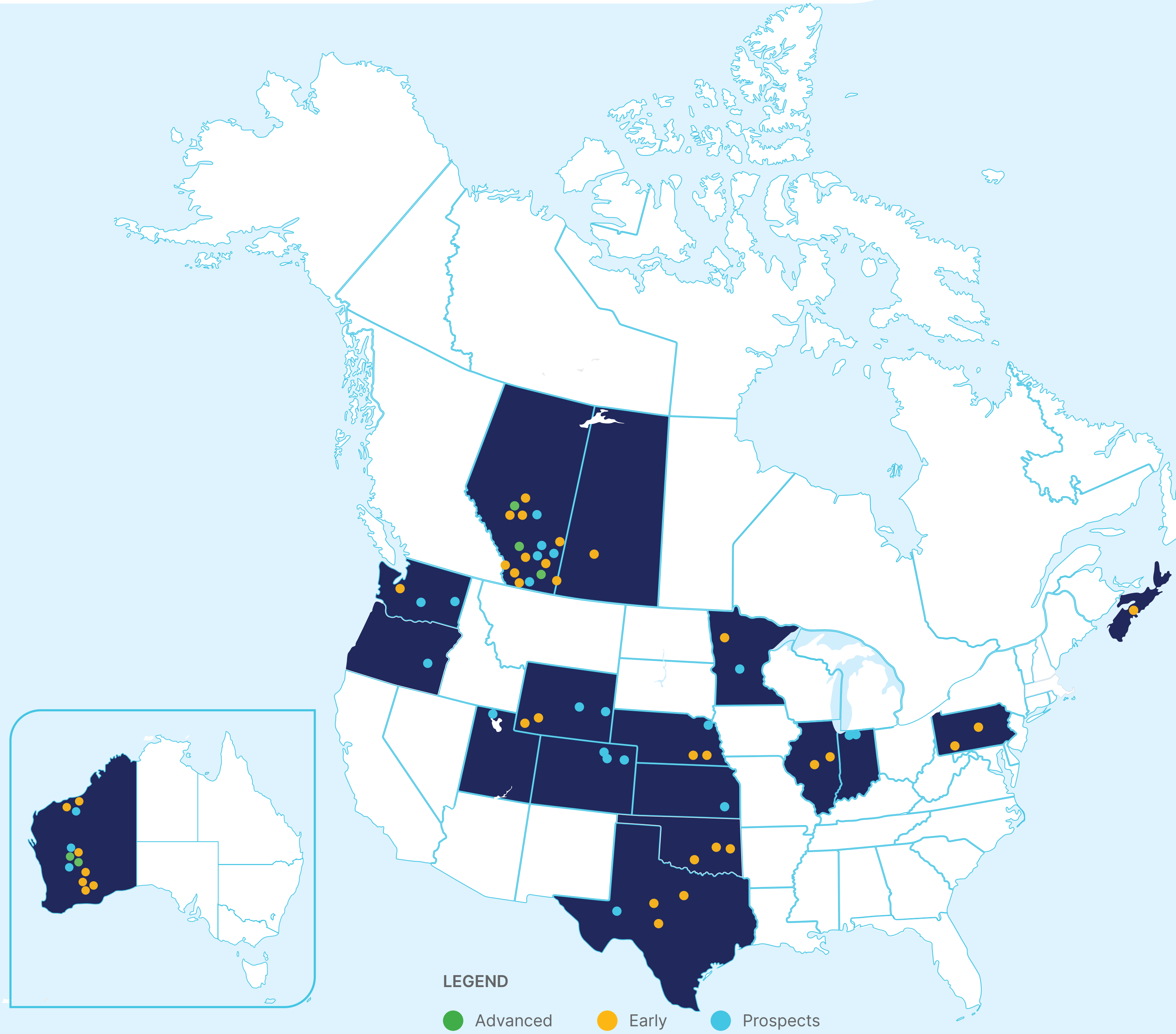
500 MW
Australia

3.2 GW
Canada

2.7 GW
United States

Prospects

3.0 GW



* Prospects as of December 31, 2023.

PLEASE NOTE: Prospects are subject to change. There is no certainty that the prospects indicated on the map above will move forward to early and advanced stage projects.


Northern Goldfields, Western Australia

Where We Are Going

We believe the current decade will be one of significant clean energy expansion and opportunities, and we are excited about the role that TransAlta will play. We have a proven track record along with the expertise and experience to meet the challenge.

Where We Are Going

Clean Electricity Growth Plan to 2028

Up to
1.75 GW
Clean electricity

$350 million
New annual EBITDA

2024 → 2028

$3.5 billion
Growth capex

10 GW
Development pipeline

Our investment focus to 2028

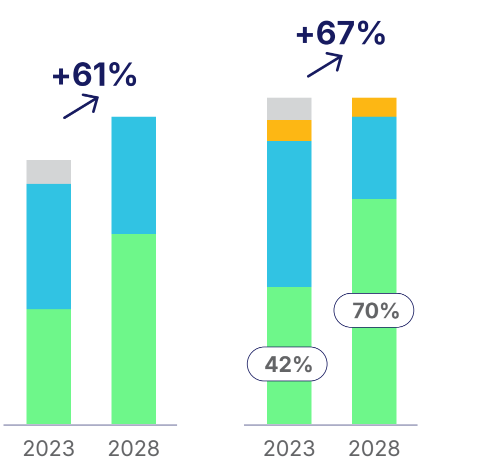
- Renewables and storage
- Responsive and flexible generation
- New technologies

Evolution of the Company

Renewables

Capacity
(MW)*

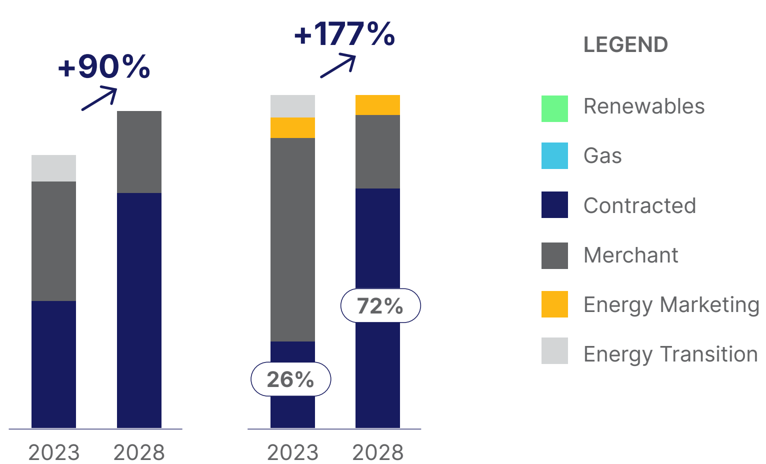
Adjusted EBITDA
(%)



Contracted

Capacity
(MW)

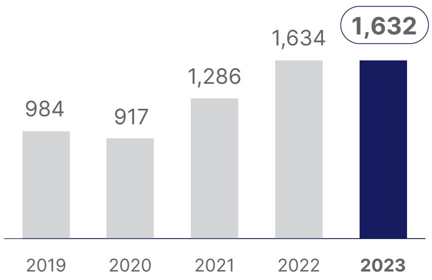
Adjusted EBITDA
(%)



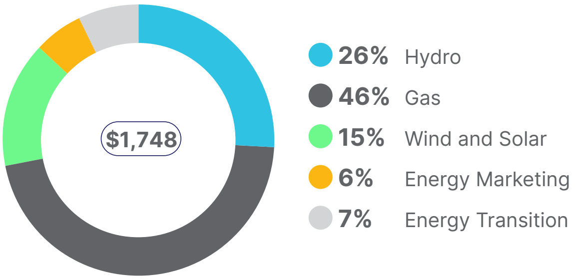
* Includes Horizon Hill, White Rock, the Clean Electricity Growth Plan and assets from the Heartland acquisition.

Financial Highlights

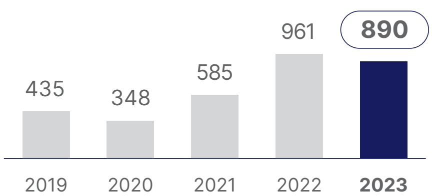
Adjusted EBITDA[1]
($ millions)



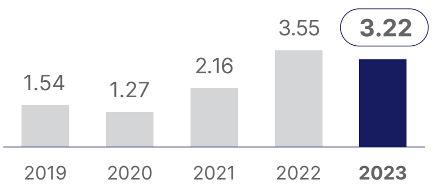
2023 Adjusted EBITDA by Segment[2]
($ millions)



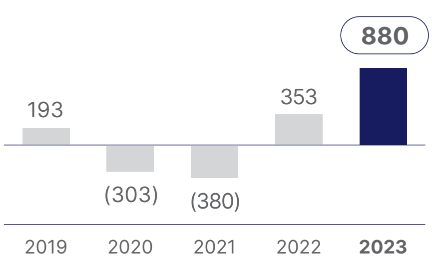
Free Cash Flow[1]
($ millions)



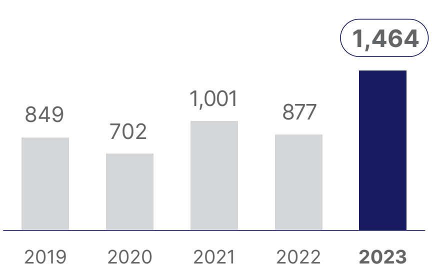
Free Cash Flow per Share[1]
($)



Earnings (Loss) before Income Taxes
($ millions)



Cash Flow from Operating Activities
($ millions)



(1) Non-IFRS measure. See pages M48 to M58.

(2) Excludes the results from the Corporate segment and our equity investments.

Hydro

Year ended Dec. 31	2023	2022	2021
Installed capacity (MW)[1]	**922**	922	925
Production (GWh)	**1,769**	1,988	1,936
Ancillary volumes (GWh)	**2,582**	3,124	2,897
Revenues[2]	**529**	607	383
Gross margin[3]	**510**	585	367
Adjusted EBITDA[3]	**459**	527	322

Gas

Year ended Dec. 31	2023	2022	2021
Installed capacity (MW)[1]	**3,084**	3,084	3,084
Production (GWh)	**11,873**	11,448	10,565
Revenues[2]	**1,525**	1,521	1,126
Gross margin[3]	**964**	801	634
Adjusted EBITDA[3]	**801**	629	488

Energy Marketing

Year ended Dec. 31	2023	2022	2021
Revenues[2]	**152**	218	202
Adjusted EBITDA[3]	**109**	183	166

Consolidated

Year ended Dec. 31	2023	2022	2021
Installed capacity (MW)[1]	**6,761**	6,583	7,387
Total production (GWh)	**22,029**	21,258	22,105
Revenues[4]	**3,355**	2,976	2,721
Adjusted EBITDA[3]	**1,632**	1,634	1,286

Wind and Solar

Year ended Dec. 31	2023	2022	2021
Installed capacity (MW)[1]	**2,084**	1,906	1,906
Production (GWh)	**4,243**	4,248	3,898
Revenues[2]	**373**	407	348
Gross margin[3]	**343**	375	331
Adjusted EBITDA[3]	**257**	311	262

Energy Transition

Year ended Dec. 31	2023	2022	2021
Installed capacity (MW)[1]	**671**	671	1,472
Production (GWh)	**4,144**	3,574	5,706
Revenues[2]	**746**	724	728
Gross margin[3]	**189**	159	236
Adjusted EBITDA[3]	**122**	86	133

Corporate

Year ended Dec. 31	2023	2022	2021
OM&A	**(115)**	(101)	(84)
Adjusted EBITDA[3]	**(116)**	(102)	(85)

(1) Gross installed capacity.
(2) For details of the adjustments to revenues included in adjusted EBITDA refer to the Additional IFRS and Non-IFRS Measures section of the MD&A.
(3) Adjusted EBITDA and gross margin are not defined and have no standardized meaning under IFRS. Refer to the Additional IFRS and Non-IFRS Measures section of the MD&A. See pages M48 to M52.
(4) In accordance with IFRS.

How We Are Doing It

As a customer-centred clean electricity leader, we are well-positioned to support the ESG and sustainability goals of our customers through a responsible energy transition. Our strategy focuses on renewable electricity growth, reliability and a deep commitment to sustainability. We believe we are uniquely positioned as the world continues to electrify and adopt sustainability practices.

Sustainability Targets

Achieving Results

Our 2023 and longer-term sustainability targets support the long-term success of our business so that the Company will continue to be positioned as an ESG leader in the future. We establish goals and targets to improve our ESG performance and to manage both current and emerging material sustainability issues.

Nine UN SDGs we support

2023 ESG Highlights

Our performance against a selection of 2023 sustainability targets is highlighted below:

ENVIRONMENT
GHG emissions reduction

Absolute 75%

2015 Baseline — 2026 goal

Down 66% from baseline

SOCIAL
Workforce diversity

Gender 40%

0 — 2030 goal

27% women

GOVERNANCE
Board diversity

Gender 50%

0 — 2030 goal

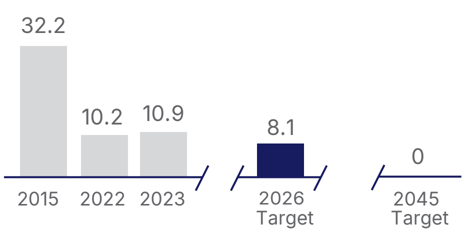
46% women

Clean Electricity Transition

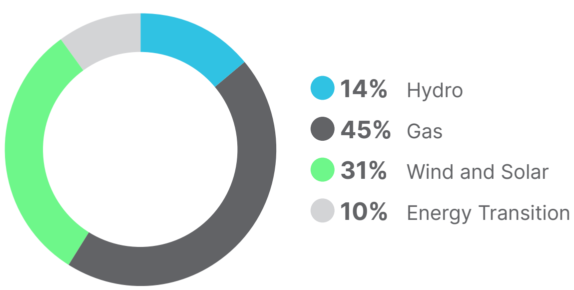
Delivering on our Clean Electricity Growth Plan

We are focused on achieving tangible greenhouse gas emissions reductions. We have adopted a net-zero by 2045 target and an ambitious CO_2 emissions reduction target of 75% by 2026 from 2015 levels.

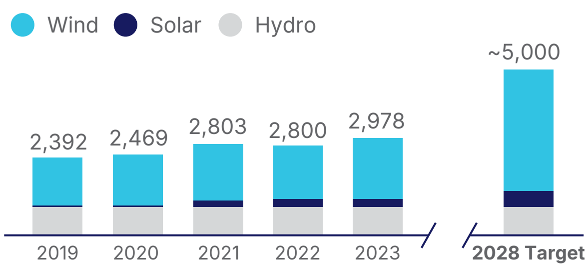
TransAlta GHG Emissions (million tonnes CO_2)



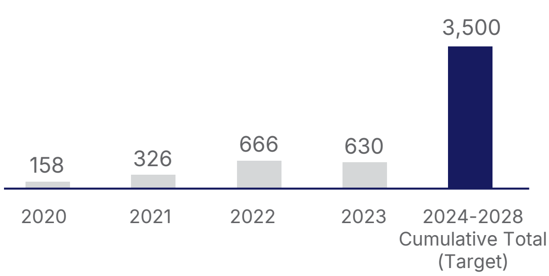
Composition of Generation Fleet



Installed Renewable Capacity (MW)



Renewable Growth Capital[1] ($ millions)



(1) See page M92 of the MD&A for details.

Committed to a Sustainable Future

Achieving Net Zero by 2045

2020

2021

2021–2026

Retired last **coal** unit in Canada in 2021

Replaced 800 MW of **gas** generation with 800 MW of **renewables** under our Clean Electricity Growth Plan ("the Plan")

Updated the Plan to **add 1.75 GW** of **renewables** by 2028

Retiring last coal unit at the end of 2025

2025

2026

2026–2030

Continue **delivering** the Plan

2030

2030–2045

Continued **growth** in **renewables**

Introduction of **net-zero technologies**

2035

2040

2045

Net Zero

Energy Innovation Outlook

(Technologies being explored)

TransAlta fleet **EV** pilot

WaterCharger 180 MW **lithium-ion** battery storage

Commercial **hydrogen** hubs and turbines

Tent Mountain **pumped hydro storage**

Brazeau **pumped storage**

Commercial small modular **fission reactors**

Commercial **fusion reactors**

Culture

Cultural Transformation Journey

Supporting health and wellbeing
- Raising awareness by becoming thriving corporate athletes

Enhancing the employee experience
- Listening to our employees, evolving the future of work

Increasing connection and collaboration
- Building culture champions

Enhancing employee psychological safety
- Creating a culture of results, learning and purpose through speaking up

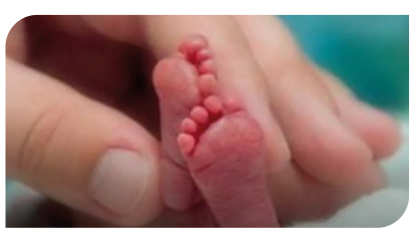
Driving results and recognition
- Rewarding performance and increasing engagement

Community Investment

In 2023, TransAlta contributed approximately $3.2 million in donations and sponsorships.

United Way

In 2023, TransAlta employees, retirees, contractors and the Company raised over $1.5 million for the United Way across Canada and the US.



Calgary Health Foundation

In 2023, TransAlta donated the final $200,000 of its $2 million commitment to develop a Neonatal Intensive Care Unit at Foothills Medical Centre to serve all of southern Alberta.

Centralia Coal Transition Board

Since 2012, TransAlta has been supporting community investments in the arts, colleges and in programs to support displaced workers under a US$55 million commitment to Washington State.

Awards & Recognition

TransAlta has been recognized in recent years for our performance as a responsible operator and proud community member where we work and live. Our ESG performance continues to be celebrated.

TransAlta Corporation ranked first on **Newsweek's** inaugural **World's Most Trustworthy Companies 2023** list for the Energy and Utilities category.

TransAlta Corporation received a score of **AA**, which is the second-highest rating given by MSCI on ESG-related business practices.

TransAlta Corporation received an **A-**, which is in the Leadership band. This is above the thermal power generation sector average of B.

TransAlta Corporation received three awards for **best overall (mid-cap) in the utilities sector, best ESG reporting (mid-cap) and best innovation** in shareholder communications.

Bloomberg Gender-Equality Index (2020 to 2023)

Human Resources Director – Best Places to Work Award (2023)

Electricity Canada's Women in Electricity Award (2023)

Diversio certified for our Equity, Diversity and Inclusion program

Energy Intelligence Green Utilities Report (2020 to 2023)

Alberta Business Awards 2023 – Health and Wellness Award of Distinction

United Way Thanks a Million Recipient (2001-2023)

Canadian Occupational Safety – Canada's Safest Employers Award for Best Wellness Program (2023)

TRANSALTA CORPORATION Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") contains forward-looking statements. These statements are based on certain estimates and assumptions and involve risks and uncertainties. Actual results may differ materially. Refer to the Forward-Looking Statements section of this MD&A for additional information.

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This MD&A should be read in conjunction with our 2023 audited annual consolidated financial statements (the "consolidated financial statements") and our 2023 Annual Information Form ("AIF"), each for the fiscal year ended Dec. 31, 2023. In this MD&A, unless the context otherwise requires, "we", "our", "us", the "Company" and "TransAlta" refer to TransAlta Corporation and its subsidiaries. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") for Canadian publicly accountable enterprises as issued by the International Accounting Standards Board ("IASB") and in effect at Dec. 31, 2023. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted, except amounts per share, which are in whole dollars to the nearest two decimals. This MD&A is dated Feb. 22, 2024. Additional information respecting TransAlta, including our AIF for the year ended Dec. 31, 2023, is available on SEDAR+ at ***www.sedarplus.ca****, on EDGAR at* ***www.sec.gov*** *and on our website at* ***www.transalta.com****. Information on or connected to our website is not incorporated by reference herein.*

Forward-Looking Statements

This MD&A includes "forward-looking information" within the meaning of applicable Canadian securities laws and "forward-looking statements" within the meaning of applicable United States securities laws, including the *Private Securities Litigation Reform Act* of 1995 (collectively referred to herein as "forward-looking statements"). All forward-looking statements are based on our beliefs as well as assumptions based on information available at the time the assumption was made and on management's experience and perception of historical trends, current conditions and expected future developments, as well as other factors deemed appropriate in the circumstances. Forward-looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "can", "could", "would", "shall", "believe", "expect", "estimate", "anticipate", "intend", "plan", "forecast", "foresee", "potential", "enable", "continue" or other comparable terminology. These statements are not guarantees of our future performance, events or results and are subject to risks, uncertainties and other important factors that could cause our actual performance, events or results to be materially different from those set out in or implied by the forward-looking statements.

In particular, this MD&A contains forward-looking statements including, but not limited to, statements relating to: the acquisition of Heartland (as defined below) and its entire business operations in Alberta and British Columbia, including closing conditions and regulatory approvals pursuant to the Heartland acquisition and the anticipated timing and completion of the acquisition; the annual average earnings before interest, taxes, depreciation and amortization ("EBITDA") to be generated from the Heartland acquisition and other benefits expected to arise from such transaction; the Company's 2024 Outlook, including Adjusted EBITDA, free cash flow, annualized dividend per share, sustaining capital and energy marketing gross margin; the Company's expanded growth targets to deliver 1.75 GW with a target investment of $3.5 billion by 2028 which is anticipated to deliver annual EBITDA of $350 million; the expansion of the Company's development pipeline to 10 GW by 2028; the Company's investment strategy to deliver long-term value to shareholders; the common share dividend level through 2024; the Company's projects under construction, including capital costs, the timing of commercial operations and expected annual EBITDA; the impact of new asset additions in 2024 of Garden Plain, Northern Goldfields solar, Kent Hills, Mount Keith transmission, White Rock and Horizon Hill; the development of the early-stage and advanced-stage projects; achieving the anticipated benefits of the transfer of PTCs (defined below) generated from the White Rock and Horizon Hill wind projects; executing growth with Hancock under the Joint Development Agreement; the proportion of EBITDA to be generated from renewable sources to increase to 70 per cent by the end of 2028; the Company's ability to achieve its long-term decarbonization goal to be net zero by 2045; the reduction of carbon emissions by 75 per cent from 2015 emissions levels by 2026; the expected impact and quantum of carbon compliance costs; regulatory developments and their expected impact on the Company; expectations regarding refinancing debt; and the Company continuing to maintain adequate liquidity.

The forward-looking statements contained in this MD&A are based on many assumptions including, but not limited to, the following: no significant changes to applicable laws and regulations beyond those that have already been announced; no significant changes to fuel and purchased power costs; no material adverse impacts to long-term investment and credit markets; no significant changes to power price and hedging assumptions, including hedged volumes and prices; no significant changes to gas commodity prices and transport costs; no significant changes to decommissioning and restoration costs; no significant changes to interest rates; no significant changes to the demand and growth of renewables generation; no significant changes to the integrity and reliability of our assets; planned and unplanned outages and use of our assets; and no significant changes to the Company's debt and credit ratings.

Forward-looking statements are subject to a number of significant risks and uncertainties that could cause actual plans, performance, results or outcomes to differ materially from current expectations. Factors that may adversely impact what is expressed or implied by forward-looking statements contained in this MD&A include risks relating to: fluctuations in power prices, including merchant pricing in Alberta, Ontario and Mid-Columbia; failure or delay in closing the Heartland acquisition; failure to realize the benefits of the Heartland acquisition, including the inability to advance the Battle River Carbon Hub Project to final investment decision or commercial operation, and any loss of value in the Heartland portfolio during the interim period prior to closing; reductions in production; restricted access to capital and increased borrowing costs, including any difficulty raising debt, equity or tax equity, as applicable, on reasonable terms or at all; labour relations matters, reduced labour availability and the ability to continue to staff our operations and facilities; reliance on key personnel; disruptions to our supply chains, including our ability to secure necessary equipment; force majeure claims; our ability to obtain regulatory and any other third-party approvals on the expected timelines or at all in respect of our growth projects; long-term commitments on gas transportation capacity that may not be fully utilized over time; adverse financial impacts arising from the Company's hedged position; risks associated with development and construction projects, including as it pertains to increased capital costs, permitting, labour and engineering risks, disputes with contractors and potential delays in the construction or commissioning of such projects; significant fluctuations in the Canadian dollar against the US dollar and Australian dollar; changes in short-term and long-term electricity supply and demand; counterparty credit risk and any higher rate of losses on our accounts receivables; inability to achieve our environmental, social and governance ("ESG") targets; the impact of the energy transition on our business; impairments and/or writedowns of assets; adverse impacts on our information technology systems and our internal control systems, including cybersecurity threats; commodity risk management and energy trading risks, including the effectiveness of the Company's risk management tools associated with hedging and trading procedures to protect against significant losses; our ability to contract our generation for prices that will provide expected returns and to replace contracts as they expire; changes to the legislative, regulatory and political environments in the jurisdictions in which we operate; environmental requirements and changes in, or liabilities under, these requirements; disruptions in the transmission and distribution of electricity; the effects of weather, including man-made or natural disasters and other climate-change related risks; increases in costs; reductions to our generating units' relative efficiency or capacity factors; disruptions in the source of fuels, including natural gas, coal, water, solar or wind resources required to operate our facilities; operational risks, unplanned outages and equipment failure and our ability to carry out or have completed any repairs in a cost-effective or timely manner or at all; failure to meet financial expectations; general domestic and international economic and political developments, including armed hostilities, the threat of terrorism, adverse diplomatic developments or other similar events; industry risk and competition in the business in which we operate; structural subordination of securities; public health crisis risks; inadequacy or unavailability of insurance coverage; our provision for income taxes and any risk of reassessment; and legal, regulatory and contractual disputes and proceedings involving the Company. The foregoing risk factors, among others, are described in further detail in the Governance and Risk Management section of this MD&A and the Risk Factors section in our AIF for the year ended Dec. 31, 2023.

Readers are urged to consider these factors carefully when evaluating the forward-looking statements, which reflect the Company's expectations only as of the date hereof and are cautioned not to place undue reliance on them. The forward-looking statements included in this document are made only as of the date hereof and we do not undertake to publicly update these forward-looking statements to reflect new information, future events or otherwise, except as required by applicable laws. The purpose of the financial outlooks contained herein is to give the reader information about management's current expectations and plans and readers are cautioned that such information may not be appropriate for other purposes. In light of these risks, uncertainties and assumptions, the forward-looking statements might occur to a different extent or at a different time than we have described, or might not occur at all. We cannot assure that projected results or events will be achieved.

Description of the Business

TransAlta is a Canadian corporation and one of Canada's largest publicly traded power generators. Established in 1911, the Company now has over 112 years of operating experience in the development, production and sale of electricity. We own, operate and manage a geographically diversified portfolio of generation assets that include water, wind, solar, battery storage, natural gas and transition coal. We are one of the largest producers of wind power in Canada and the largest producer of hydro power in Alberta. We also have industry-leading energy marketing capabilities where we seek to maximize margins by securing and optimizing high-value products and markets for ourselves and our customers in dynamic market conditions. Our mix of merchant and contracted assets along with our energy marketing business provides resilient and growing cash flows that support our ability to pay dividends to our shareholders and reinvest in growth.

The Company's goal is to be a leading clean electricity company that is committed to a sustainable future and a responsible energy transition. Our strategic priorities include accelerating growth into customer-centred renewables and storage, selectively expanding flexible generation and reliability assets to support the transition, defining the next generation of power solutions and maintaining financial strength and capital allocation discipline. We are primarily focused on opportunities within our core markets of Canada, the US and Western Australia.

Our sustainability goals and our Clean Electricity Growth Plan remain the focus of our strategy, which includes our commitment to retire our last remaining operational coal facility at the end of 2025. We remain on track to achieve our 2026 greenhouse gas ("GHG") emissions reduction target of 75 per cent scope 1 and 2 GHG emissions reductions since 2015 and our carbon net-zero goal by 2045. Since 2005, we have reduced our scope 1 and 2 GHG emissions by 31 million tonnes ("MT") of CO_2e or a 74 per cent reduction, proudly representing approximately 10 per cent of Canada's Paris Agreement 2030 decarbonization target(1).

Portfolio of Assets

Our asset portfolio is geographically diversified with operations across Canada, the United States and Australia. The portfolio also generates power using a diverse set generation technologies and reliably supplies a broad cross section of counterparties.

Our Hydro, Wind and Solar, Gas and Energy Transition segments are responsible for operating and maintaining our electrical generation facilities. Our Energy Marketing segment is responsible for marketing and scheduling our merchant asset fleet in North America (excluding Alberta) along with the procurement of gas, transport and storage for our gas fleet, providing knowledge to support our growth team, and generating a stand-alone gross margin separate from our asset business through a leading North American energy marketing and trading platform.

Our highly diversified portfolio consists of both high-quality contracted assets and merchant assets. Approximately, 56 percent of our total installed capacity, including 81 per cent of our Wind and Solar fleet and 53 per cent of our Gas fleet, is contracted with investment-grade or creditworthy counterparties. The weighted-average contract life for these contracted facilities is 10 years.

Our merchant assets include our unique hydro merchant portfolio and our merchant legacy thermal portfolio and wind assets. Our merchant exposure is primarily in Alberta, where 53 per cent of our capacity is located and 75 per cent of our Alberta capacity is available to participate in the merchant market. The Alberta optimization team is responsible for marketing and scheduling our merchant asset fleet in Alberta.

A significant portion of the thermal generation capacity in the portfolio has been hedged to provide cash flow certainty. The Company's hedging strategy includes maintaining a significant base of commercial and industrial customers and is supplemented with financial hedges. In 2023, 78 per cent of our energy production in Alberta was sold under long term contracts or fixed price hedges. Refer to the 2024 Outlook section and the Optimization of the Alberta Portfolio of this MD&A for further details.

Our diversified fleet is a key success factor in our ability to deliver resilient cash flows while capturing higher risk-adjusted returns for our shareholders.

(1) In 2005, TransAlta's estimated scope 1 and 2 GHG emissions were 41.9 MT of CO_2e, which did not receive independent limited assurance. Canada's Paris Agreement 2030 decarbonization target assumed 293 MT of CO_2e or a 40 per cent reduction from a 2005 baseline of 732 MT of CO_2e.

The following table provides our consolidated ownership of our facilities across the regions in which we operate as of Dec. 31, 2023:

	Hydro		Wind & Solar		Gas		Energy Transition		Total	
Year ended Dec. 31, 2023	Gross Installed Capacity (MW)	Number of facilities	Gross Installed Capacity (MW)(1)	Number of facilities	Gross Installed Capacity (MW)(1)	Number of facilities	Gross Installed Capacity (MW)	Number of facilities	Gross Installed Capacity (MW)(1)	Number of facilities
Alberta	834	17	766	14	1,960	7	—	—	3,560	38
Canada, excluding Alberta	88	7	751	9	645	3	—	—	1,484	19
US	—	—	519	7	29	1	671	2	1,219	10
Australia	—	—	48	3	450	6	—	—	498	9
Total	**922**	**24**	**2,084**	**33**	**3,084**	**17**	**671**	**2**	**6,761**	**76**

(1) Gross installed capacity for consolidated reporting represents 100 per cent output of a facility. Capacity figures for the Wind and Solar segment includes 100 per cent of the Kent Hills wind facilities, and capacity figures for the Gas segment include 100 per cent of the Ottawa and Windsor facilities, 100 per cent of the Poplar Creek facility, 50 per cent of the Sheerness facility and 60 per cent of the Fort Saskatchewan facility.

Stable and Predictable Cash Flows

The following table provides our contracted capacity by MW and as a percentage of total gross installed capacity of our facilities across the regions in which we operate as of Dec. 31, 2023:

As at Dec. 31, 2023	Hydro	Wind & Solar	Gas	Energy Transition	Total
Alberta	—	374	511	—	885
Canada, excluding Alberta	88	751	645	—	1,484
US	—	519	29	381	929
Australia	—	48	450	—	498
Total contracted capacity (MW)	88	1,692	1,635	381	3,796
Contracted capacity as a % of total capacity (%)	10%	81%	53%	57%	56%

The weighted average contract life (years) of our facilities across the regions in which we operate as of Dec. 31, 2023 is:

As at Dec. 31, 2023	Hydro	Wind & Solar	Gas	Energy Transition	Total
Alberta(1)(2)	—	16	7	—	11
Canada, excluding Alberta(2)	10	10	8	—	9
US(2)	—	10	2	2	7
Australia(2)	—	15	15	—	15
Total weighted contract life (years)(2)	10	12	10	2	10

(1) The weighted-average remaining contract life in the Wind and Solar segment is related to the contract period for Garden Plain (130 MW), McBride Lake (38 MW), and Windrise (206 MW). The weighted-average remaining contract life in the Gas segment is related to the contract period for Poplar Creek (230 MW), Fort Saskatchewan (71 MW) and a capacity-contract that is not directly contracted with any one facility (210 MW).

(2) For power generated under long-term power purchase agreements ("PPAs") and other long-term contracts, the weighted-average remaining contract life is based on long-term average gross installed capacity.

The majority of TransAlta's long-term power purchase agreements are with investment-grade rated or creditworthy counterparties.

Highlights

For the year ended Dec. 31, 2023, the Company demonstrated strong performance mainly due to the continued strong market conditions in Alberta in the first half of the year, higher production in the Gas and Energy Transition segments, and higher hedged volumes and lower realized gas prices in the Gas segment, partially offset by lower wind and water resources. The Energy Marketing segment's performance was lower compared to 2022 due to the lower realized settled trades during the year on market positions compared to the prior year.

Year ended Dec. 31	2023	2022	2021
Operational information			
Adjusted availability (%)	**88.8**	90.0	86.6
Production (GWh)	**22,029**	21,258	22,105
Select financial information			
Revenues	**3,355**	2,976	2,721
Earnings (loss) before income taxes	**880**	353	(380)
Adjusted EBITDA(1)	**1,632**	1,634	1,286
Net earnings (loss) attributable to common shareholders	**644**	4	(576)
Cash flows			
Cash flow from operating activities	**1,464**	877	1,001
Funds from operations(1)	**1,351**	1,346	994
Free cash flow(1)	**890**	961	585
Per share			
Weighted average number of common shares outstanding	**276**	271	271
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**2.33**	0.01	(2.13)
Dividends declared per common share	**0.22**	0.21	0.19
Funds from operations per share(1)(2)	**4.89**	4.97	3.67
Free cash flow per share(1)(2)	**3.22**	3.55	2.16
Liquidity and capital resources			
Available liquidity	**1,738**	2,118	2,177
Adjusted net debt to adjusted EBITDA(1) (times)	**2.5**	2.2	2.6
Total consolidated net debt(1)(3)	**3,453**	2,854	2,636

As at Dec. 31	2023	2022	2021
Total assets	**8,659**	10,741	9,226
Total long-term liabilities	**5,253**	5,864	4,702
Total liabilities	**6,995**	8,752	6,633

(1) These items are not defined and have no standardized meaning under IFRS. Presenting these items from period to period provides management and investors with the ability to evaluate earnings (loss) trends more readily in comparison with prior periods' results. Refer to the Segmented Financial Performance and Operating Results section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS. Also, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(2) Funds from operations ("FFO") per share and free cash flow ("FCF") per share are calculated using the weighted average number of common shares outstanding during the period. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for the purpose of these non-IFRS ratios.

(3) Refer to the table in the Financial Capital section of this MD&A for more details on the composition of total consolidated net debt.

Operating Performance

Adjusted Availability

The following table provides adjusted availability (%) by segment:

Year ended Dec. 31	2023	2022	2021
Hydro	**90.8**	96.7	92.4
Wind and Solar	**86.9**	83.8	91.9
Gas	**91.6**	94.6	85.7
Energy Transition(1)	**79.8**	79.0	78.8
Adjusted availability (%)	**88.8**	90.0	86.6

(1) Availability, not adjusted for dispatch optimization, was 79.8 per cent for the year ended Dec. 31, 2023 (2022 - 77.2 per cent; 2021 - 75.3 per cent).

Availability is an important measure for the Company as it represents the percentage of time a facility is available to produce electricity and is therefore an important indicator of the overall performance of the fleet.

Availability is impacted by planned and unplanned outages, including the extended outage at the Kent Hills wind facility within the Wind and Solar fleet. Availability adjusted to exclude the Kent Hills extended outage for the years ended Dec. 31, 2022 and 2023, was 91.0 per cent and 92.8 per cent, respectively. The Company schedules dedicated time (planned outages) to maintain, repair or make improvements to the facilities at a time that will minimize the impact to the operations. In high price environments, actual outage schedules may change to accelerate the return to service of the unit.

Adjusted availability for the year ended Dec. 31, 2023, was 88.8 per cent, compared to 90.0 per cent in 2022, and was consistent with management's expectations. Lower adjusted availability was primarily due to:

- Planned outages in the Hydro segment, mainly at our Alberta Hydro Assets, to perform scheduled maintenance and
- Planned outages at Sundance Unit 6, Sheerness Unit 1, Keephills Units 2 and 3 and Sarnia for scheduled maintenance in the Gas segment, partially offset by
- Lower planned outages at Centralia Unit 2 in the Energy Transition segment and
- The partial return to service of the Kent Hills wind facilities.

Production and Long-Term Average Generation

	2023			2022			2021		
Year ended Dec. 31	Actual production (GWh)	LTA generation (GWh)	Production as a % of LTA	Actual production (GWh)	LTA generation (GWh)	Production as a % of LTA	Actual production (GWh)	LTA generation (GWh)	Production as a % of LTA
Hydro	**1,769**	**2,015**	**88%**	1,988	2,015	99%	1,936	2,030	95%
Wind and Solar	**4,243**	**5,387**	**79%**	4,248	4,950	86%	3,898	4,345	90%
Gas	**11,873**			11,448			10,565		
Energy Transition	**4,144**			3,574			5,706		
Total	**22,029**			21,258			22,105		

In addition to adjusted availability, the Company utilizes long-term average production ("LTA generation") as another indicator of performance for the renewable assets whereby actual production levels are compared against the expected long-term average. In the short term, for each of the Hydro and Wind and Solar segments, the conditions will vary from one period to the next. Over longer durations, facilities are expected to produce in line with their long-term averages, which is considered a reliable indicator of performance.

LTA generation is calculated on an annualized basis from the average annual energy yield predicted from our simulation model based on historical resource data performed over a period of typically greater than 25 years.

LTA generation for Energy Transition is not considered as we are currently transitioning these units with the expectation that they will retire by the end of 2025 and the LTA generation for Gas is not applicable as these units are dispatchable and their production is largely dependent on market conditions and merchant demand.

Total production for 2023, increased by 771 GWh or 4 per cent compared to 2022.

Production from the Centralia facility within the Energy Transition segment benefited from fewer planned and unplanned outage hours compared to the prior year and was able to be dispatched during periods of higher merchant pricing for the region.

The Company's Gas segment had a strong performance, resulting in production that was both higher than the prior year as well as higher than expectations for the year. The Gas segment was available during periods of supply tightness, allowing for the Company to operate during periods of peak pricing. The Gas segment was unfavourably impacted by relatively mild weather in the fourth quarter of 2023, as the Company did not experience the same weather conditions compared to the same period in 2022, which had tighter supply due to the extreme cold weather in Alberta.

Production for our renewables assets for the year ended Dec. 31, 2023, was lower by 224 GWh, or 4 per cent, compared to 2022 and was 81 per cent of LTA generation.

Lower than average renewable resources in the year impacted production in both the Hydro and the Wind and Solar segments. Hydro production was further impacted by lower availability due to increased planned maintenance outages compared to 2022, while the Wind and Solar segment production was positively impacted by the addition of the Garden Plain wind facility, the partial return to service of the Kent Hills wind facility and the addition of the Northern Goldfields solar facilities during the year.

Market Pricing

Year ended Dec. 31, 2023	2023	2022	2021
Alberta spot power price ($/MWh)	**134**	162	102
Mid-Columbia spot power price (US$/MWh)	**76**	82	49
Ontario spot power price ($/MWh)	**28**	47	30
Natural gas price (AECO) per GJ ($)	**2.54**	5.08	3.39

For the year ended Dec. 31, 2023, spot electricity prices in Alberta and the Pacific Northwest were lower compared to 2022. Lower prices in both regions resulted from lower natural gas prices and overall weaker weather-driven demand in the second half of 2023, with notably lower prices due to above normal weather patterns in the fourth quarter of 2023. For Alberta specifically, warm weather in the fourth quarter resulted in a strong wind resource pattern which, combined with new installed capacity, added supply in the market compared to the prior year.

AECO natural gas prices for the year ended Dec. 31, 2023, were lower compared to 2022 mainly due to improved production and storage levels in Alberta and North America.

Financial Performance review on Consolidated Information

Year ended Dec. 31	2023	2022	2021
Revenues	**3,355**	2,976	2,721
Fuel and purchased power	**1,060**	1,263	1,054
Carbon compliance	**112**	78	178
Operations, maintenance and administration	**539**	521	511
Depreciation and amortization	**621**	599	529
Asset impairment charges (reversals)	**(48)**	9	648
Interest income	**59**	24	11
Earnings (loss) before income taxes	**880**	353	(380)
Income tax expense	**84**	192	45
Net earnings (loss) attributable to common shareholders	**644**	4	(576)
Net earnings attributable to non-controlling interests	**101**	111	112

Current Year Variance Analysis (2023 versus 2022)

Revenues totalling $3,355 million, increased by $379 million, or 13 per cent, compared to 2022, primarily due to:

- Higher realized and unrealized gains from hedging and derivative positions across the segments, partially offset by
- Lower revenue from merchant sales due to lower spot power prices and production in Alberta.

Fuel and purchased power costs totalling $1,060 million, decreased by $203 million, or 16 per cent, compared to 2022, primarily due to:

- Lower natural gas commodity pricing, partially offset by
- Higher fuel usage in both the Gas and Energy Transition segments.

Carbon compliance costs totalling $112 million, increased by $34 million, or 44 per cent, compared to 2022, primarily due to:

- An increase in the carbon price per tonne from $50 per tonne in 2022 to $65 per tonne in 2023,
- Higher production in the Gas segment and
- No utilization of emission credits to settle GHG obligations as was done in the prior year.

Operations, maintenance and administration ("OM&A") expenses totalling $539 million, increased by $18 million, or 3 per cent, compared to 2022, primarily due to:

- Higher spending on strategic and growth initiatives,
- Higher costs associated with the relocation of the Company's head office and
- Increased costs due to inflationary pressures.

Depreciation and amortization totalling $621 million, increased by $22 million, or 4 per cent, compared to 2022, primarily due to:

- Revisions to useful lives on certain facilities and
- Commercial operation of new facilities.

Asset impairment reversals totalling $48 million, increased by $57 million, or 633 per cent, compared to an asset impairment charge in 2022, primarily due to:

- Decommissioning and restoration provisions for retired assets being favourably impacted by a change in timing of expected cash outflows, partially offset by lower discount rates, resulting in a net impairment reversal of $34 million and
- A Hydro segment impairment reversal of $10 million due to a contract extension and favourable changes in power price assumptions.

Interest income totalling $59 million increased by $35 million, or 146 per cent, compared to 2022, primarily due to higher cash balances and favourable interest rates.

Earnings before income taxes totalling $880 million, increased by $527 million, or 149 per cent, compared to 2022, due to the above noted items.

Income tax expense totalling $84 million, decreased by $108 million, or 56 per cent, compared to 2022, due to a recovery relating to the reversal of previously derecognized Canadian deferred tax assets and lower US non-deductible expenses relating to the US operations, partially offset by higher earnings from Canadian operations.

Net earnings attributable to non-controlling interests totalling $101 million, decreased by $10 million, or 9 per cent, compared to 2022, primarily due to lower net earnings for TA Cogen.

Adjusted EBITDA

For the year ended Dec. 31, 2023, the Company's adjusted EBITDA was $1,632 million as compared to $1,634 million in 2022, a decrease of $2 million. The major factors impacting adjusted EBITDA are summarized in the following table:

	Year ended Dec. 31
Adjusted EBITDA for the year ended Dec. 31, 2022	1,634
Hydro: lower primarily due to lower ancillary services volumes, lower spot power and ancillary services prices and lower than average water resources, partially offset by realized gains from hedging and sales of environmental attributes.	(68)
Wind and Solar: lower primarily due to lower environmental attribute revenues, lower spot power pricing in Alberta, lower wind resource across the operating fleets, lower liquidated damages recognized at the Windrise wind facility and higher OM&A, partially offset by the commercial operation of the Garden Plain wind facility, the Northern Goldfields solar facilities and the partial return of service of the Kent Hills wind facilities.	(54)
Gas: higher primarily due to higher power price hedges partially offsetting the impacts of lower Alberta spot prices, lower natural gas commodity costs and higher production, partially offset by lower thermal revenues, higher carbon prices and higher carbon costs and fuel usage related to production. The Gas fleet significantly exceeded management's expectations.	172
Energy Transition: higher primarily due to higher production from higher availability and higher merchant sales volumes, partially offset by lower market prices compared to the prior year.	36
Energy Marketing: lower primarily due to lower realized settled trades during the year on market positions in comparison to prior year and higher OM&A. Energy Marketing results were in line with management's expectations and performance was consistent with our revised full year financial guidance provided in the second quarter of 2023.	(74)
Corporate: lower primarily due to increased spending to support strategic and growth initiatives and higher costs associated with the relocation of the Company's head office.	(14)
Adjusted EBITDA[1] for the year ended Dec. 31, 2023	**1,632**

(1) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Free Cash Flow

During the second quarter of 2023, the Company revised and increased our 2023 guidance for FCF based on the strong financial performance attained in the first half of the year and our expectations for the balance of the year. For the year ended Dec. 31, 2023, the Company's FCF decreased by $71 million, or 7 per cent, compared to 2022, and was in line with our revised expected full year financial guidance. The major factors impacting FCF are summarized in the following table:

	Year ended Dec. 31
FCF for the year ended Dec. 31, 2022	961
Lower adjusted EBITDA: lower FCF due to the items noted in Adjusted EBITDA above.	(2)
Higher interest income: Higher cash balances and favourable interest rates positively impacting FCF.	35
Lower current income tax expense: Previously restricted non-capital loss carryforwards were utilized to offset taxable income resulting in higher FCF.	15
Higher sustaining capital expenditures: Higher planned major maintenance costs for the Hydro and Gas segments, partially offset by lower planned major maintenance in Wind and Solar and Energy Transition segments, resulting in lower FCF.	(31)
Higher distributions paid to subsidiaries' non-controlling interests: Related to timing of distributions paid to TA Cogen, partially offset by lower distributions paid to TransAlta Renewables resulting in lower FCF.	(36)
Lower provisions: Lower provisions being accrued compared to the prior year, with no notable settlements being recorded in either year resulting in lower FCF due to the timing of provisions accrued.	(26)
Other non-cash items[1]	(12)
Other[2]	(14)
FCF[3] for the year ended Dec. 31, 2023	**890**

(1) Other non-cash items consists of Alberta market pool incentives, carbon obligation, contract liabilities, and the SunHills royalty onerous contract. Refer to the Reconciliation of Cash Flow from Operations to FFO and FCF section tables in this MD&A for more details.

(2) Other consists of higher realized foreign exchange loss, higher decommissioning and restoration costs settled, higher dividends paid on preferred shares and higher principal payments on lease liabilities. Refer to the Reconciliation of Cash Flow from Operations to FFO and FCF section tables in this MD&A for more details.

(3) FCF is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Capital Expenditures

We are in a long-cycle, capital-intensive business that requires significant capital expenditures. Our goal is to undertake sustaining capital expenditures that ensure our facilities operate reliably and safely.

Year ended Dec. 31	2023	2022	2021
Hydro	**41**	35	26
Wind and Solar	**15**	18	13
Gas	**76**	41	128
Energy Transition	**15**	19	19
Corporate	**27**	29	13
Total sustaining capital expenditures	**174**	142	199

Total sustaining capital expenditures in 2023 were $32 million higher compared to 2022, primarily due to:

- Higher planned major maintenance at our Alberta Hydro Assets,
- Higher planned major maintenance at our Sarnia, Sundance Unit 6 and Keephills Units 2 and 3 facilities in the Gas segments, partially offset by
- Lower planned major maintenance in the Wind and Solar segment primarily due to a reduction in major component replacements and
- Lower planned outage work performed in the Energy Transition segment.

Total sustaining capital expenditures in 2022 were $57 million lower compared to 2021, primarily due to:

- Coal-to-gas conversions being completed in 2021, partially offset by
- Higher planned major maintenance in 2022 in the Hydro segment and a higher level of major component replacements in 2022 in the Wind and Solar segment and
- Higher spend on leasehold improvements associated with the planned relocation of the Company's head office.

Year ended Dec. 31	2023	2022	2021
Hydro	**6**	2	3
Wind and Solar	**659**	759	124
Gas	**13**	3	38
Energy Transition	**—**	—	70
Corporate(1)	**61**	10	47
Total growth and development expenditures	**739**	774	282

(1) Expenditures related to projects in the development phase are included in the Corporate segment.

In 2023 and 2022, the growth and development expenditures incurred primarily related to:

- The Garden Plain wind facility, which achieved commercial operation in August 2023;
- The Northern Goldfields solar facilities, which achieved commercial operation in November 2023;
- The White Rock wind projects, which are expected to reach commercial operation in the first quarter of 2024;
- The Horizon Hill wind project, which is expected to reach commercial operation in the first quarter of 2024; and
- The Mount Keith 132kV expansion, which is on track to be completed in the first quarter of 2024.

Refer to the Strategic Priorities and Clean Electricity Growth Plan to 2028 section of this MD&A for more details.

Significant and Subsequent Events

Change to Board of Directors

The Honourable Rona Ambrose has decided that she will not stand for re-election and will retire from the Board of Directors ("the Board") following the annual shareholder meeting on April 25, 2024. The Board extends its gratitude for her service to the Company. She has been a valuable contributor to the Board since 2017 and we thank her for her leadership and insights during her tenure, especially as Chair of the Governance, Safety and Sustainability Committee of the Board.

Production Tax Credit ("PTC") Sale Agreements

On Feb. 22, 2024, the Company entered into 10-year transfer agreements with an AA- rated customer for the sale of approximately 80 per cent of the expected PTCs to be generated from the White Rock wind projects and the Horizon Hill wind project. The expected annual average EBITDA from these contracts is approximately $57 million (US$43 million).

Normal Course Issuer Bid ("NCIB") and Automatic Share Purchase Plan ("ASPP")

On May 26, 2023, the Toronto Stock Exchange ("TSX") accepted the notice filed by the Company to implement an NCIB for a portion of its common shares. Pursuant to the NCIB, TransAlta may repurchase up to a maximum of 14,000,000 common shares, representing approximately 7.29 per cent of its public float of common shares as at May 17, 2023. Purchases under the NCIB may be made through open market transactions on the TSX and any alternative Canadian trading platforms on which the common shares are traded, based on the prevailing market price. Any common shares purchased under the NCIB will be cancelled. The period during which TransAlta is authorized to make purchases under the NCIB commenced on May 31, 2023, and ends on May 30, 2024, or such earlier date on which the maximum number of common shares are purchased under the NCIB or the NCIB is terminated at the Company's election.

On Dec. 19, 2023, the Company entered into an ASPP to facilitate repurchases of TransAlta's common shares under its NCIB.

Under the ASPP, the Company's broker may purchase common shares from the effective date of the ASPP until the end of the ASPP. All purchases of common shares made under the ASPP will be included in determining the number of common shares purchased under the NCIB. The ASPP will terminate on the earliest of the date on which: (a) the maximum purchase limits under the ASPP are reached; (b) Feb. 24, 2024; or (c) the Company terminates the ASPP in accordance with its terms.

During the year ended Dec. 31, 2023, the Company purchased and cancelled a total of 7,537,500 common shares, at an average price of $11.49 per common share, for a total cost of $87 million.

The NCIB provides the Company with a capital allocation alternative with a view to ensuring long-term shareholder value. TransAlta's Board of Directors and management believe that, from time to time, the market price of the common shares might not be reflective of the underlying value and purchases of common shares for cancellation under the NCIB may provide an opportunity to enhance shareholder value.

Northern Goldfields Solar Achieves Commercial Operation

On Nov. 22, 2023, the Company announced that the 48 MW Northern Goldfields solar and battery storage facilities achieved commercial operation. The facilities consist of the 27 MW Mount Keith solar facility, the 11 MW Leinster solar facility, the 10 MW Leinster battery energy storage system and interconnecting transmission infrastructure, all of which are now integrated into TransAlta's existing 169 MW Southern Cross Energy North remote network in Western Australia. The facilities are fully contracted to BHP Nickel West for a term of 15 years and are expected to reduce BHP's scope 2 emissions at Mount Keith and Leinster by 12 per cent annually.

TransAlta Announces Growth Targets to 2028 and Declares 9% Dividend Increase

On Nov. 21, 2023, the Company held its 2023 Investor Day event and announced it had updated its strategic growth targets to 2028, which strengthens the Company's commitment to being a leader in clean electricity by delivering customer-centred power solutions. The growth targets include:

- Adding up to 1.75 GW of new capacity to the Company's fleet by investing approximately $3.5 billion to develop, construct or acquire new assets through to the end of 2028,
- A focus on customer-centred renewables and storage through the development of its 4.8 GW development pipeline and
- Expanding the Company's development pipeline to 10 GW by 2028.

The Board approved an annualized $0.02 per share increase, or 9 per cent increase to our common share dividend and declared a dividend of $0.06 per common share to be paid on April 1, 2024. The quarterly dividend of $0.06 per common share represents an annualized dividend of $0.24 per common share.

TransAlta Enters Joint Development Agreement with Hancock

On Nov. 21, 2023, the Company entered into a joint development agreement with Hancock Prospecting Pty Ltd. ("Hancock"), Australia's fourth largest iron ore producer. This arrangement will build on TransAlta's expertise in supplying power to remote mining operations in Western Australia. TransAlta will work collaboratively with Hancock to define and supply behind-the-fence generation solutions for Hancock in the Port Hedland area.

TransAlta to Acquire Heartland Generation from Energy Capital Partners

On Nov. 2, 2023, the Company announced that it had entered into a definitive share purchase agreement with an affiliate of Energy Capital Partners, the parent of Heartland Generation Ltd. and Alberta Power (2000) Ltd. (collectively, "Heartland"), pursuant to which TransAlta will acquire Heartland and its entire business operations in Alberta and British Columbia. The acquisition will add 10 facilities to TransAlta's fleet, totalling 1,844 MW of new capacity. The transaction is expected to close in the first half of 2024, subject to customary closing conditions, including receipt of regulatory approvals.

The purchase price for the acquisition is $390 million, subject to working capital and other adjustments, as well as the assumption of $268 million of low-cost debt. The Company will finance the transaction using cash on hand and drawing on its credit facilities.

The assets are expected to add approximately $115 million of average annual EBITDA including synergies. Approximately 55 per cent of revenues are under contract with highly creditworthy counterparties, with a weighted-average remaining contract life of 16 years. Corporate pre-tax synergies are expected to exceed $20 million annually.

The acquisition will competitively position the Company to respond to the highly dynamic and shifting electricity landscape in Alberta given the expected significant increase in renewables and other large baseload generation coming online in the next several years in the province. The Clean Electricity Growth Plan continues to be at the heart of our strategy and is primarily focused on meeting the future needs of our customers with clean electricity solutions.

TransAlta Corporation Completes Acquisition of TransAlta Renewables Inc.

On Oct. 5, 2023, the Company completed the acquisition of TransAlta Renewables pursuant to the terms of the previously announced arrangement agreement between the parties (the "Arrangement"). TransAlta acquired all of the outstanding common shares of TransAlta Renewables ("RNW Shares") not already owned, directly or indirectly, by TransAlta and certain of its affiliates, resulting in TransAlta Renewables becoming a wholly owned subsidiary of the Company. Prior to the Arrangement, TransAlta and its affiliates collectively held 160,398,217 RNW Shares, representing 60.1 per cent of the issued and outstanding RNW Shares, with the remaining 106,510,884 RNW Shares held by TransAlta Renewables shareholders ("RNW Shareholders") other than TransAlta and its affiliates.

The Arrangement was approved by RNW Shareholders at a special meeting of shareholders held on Sept. 26, 2023, and by the Court of King's Bench of Alberta on Oct. 4, 2023. The consideration paid totalled $1.3 billion which consisted of $800 million of cash and approximately 46 million common shares of the Company.

The closing of the acquisition of TransAlta Renewables represents a key milestone for the Company and the simplified and unified corporate structure positions it well for future success.

TransAlta Tops Newsweek's Inaugural List of World's Most Trustworthy Companies

On Sept. 14, 2023, the Company announced that it ranked first on Newsweek's inaugural "World's Most Trustworthy Companies 2023" list for the Energy and Utilities category. The list identifies the top 1,000 companies in 21 countries and across 23 industries. Newsweek's 2023 World's Most Trustworthy Companies were chosen based on a holistic approach to evaluating three pillars of public trust – customers, investors and employees. The list was compiled based on an extensive survey of over 70,000 participants, gathering 269,000 evaluations of companies that people trust as a customer, as an investor or as an employee.

Garden Plain Wind Facility Achieved Commercial Operation

In August 2023, the Garden Plain wind facility was commissioned adding 130 MW to our gross installed capacity. The facility is fully contracted with Pembina Pipeline Corporation and PepsiCo Canada, with a weighted average contract life of approximately 17 years.

Tent Mountain Pumped Hydro Development Project

On April 24, 2023, the Company acquired a 50 per cent interest in the Tent Mountain Renewable Energy Complex ("Tent Mountain"), an early-stage 320 MW pumped storage hydro development project located in southwest Alberta, from Evolve Power Ltd. ("Evolve"), formerly known as Montem Resources Limited. The acquisition includes land rights, fixed assets and intellectual property associated with Tent Mountain.

The Company and Evolve own the Tent Mountain project within a special purpose partnership that is jointly managed, with the Company acting as project developer. The partnership is actively seeking an offtake agreement for the energy and environmental attributes that will be generated by the facility.

Annual Shareholder Meeting

On April 28, 2023, the Company held its annual meeting of shareholders. All director nominees were elected to the Board, including Candace MacGibbon, a new member to the Board.

The Company also received strong support on all other items of business, including say-on-pay and an amendment to the Company's Share Unit Plan.

Segmented Financial Performance and Operating Results

Segmented information is prepared on the same basis that the Company manages its business, evaluates financial results and makes key operating decisions. The following table reflects the summary financial information on a consolidated basis for the year ended Dec. 31:

	Adjusted EBITDA[1]		
Year ended Dec. 31	**2023**	**2022**	**2021**
Hydro	**459**	527	322
Wind and Solar	**257**	311	262
Gas	**801**	629	488
Energy Transition	**122**	86	133
Energy Marketing	**109**	183	166
Corporate	**(116)**	(102)	(85)
Total adjusted EBITDA[1]	**1,632**	1,634	1,286
Earnings (loss) before income taxes	**880**	353	(380)

(1) This item is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Hydro

Year ended Dec. 31	2023	2022	Change		2021	Change	
Gross installed capacity (MW)[1]	922	922	—	— %	925	(3)	— %
LTA generation (GWh)[2]	2,015	2,015	—	— %	2,030	(15)	(1)%
Availability (%)	90.8	96.7	(5.9)	(6)%	92.4	4.3	5 %
Production							
Contract production (GWh)	277	323	(46)	(14)%	434	(111)	(26)%
Merchant production (GWh)	1,492	1,665	(173)	(10)%	1,502	163	11 %
Total energy production (GWh)	1,769	1,988	(219)	(11)%	1,936	52	3 %
Ancillary service volumes (GWh)[3]	2,582	3,124	(542)	(17)%	2,897	227	8 %
Alberta Hydro Assets revenues[4][5]	291	328	(37)	(11)%	185	143	77 %
Other Hydro Assets and other revenues[4][6]	51	42	9	21 %	41	1	2 %
Alberta Hydro ancillary services revenues[3]	173	236	(63)	(27)%	160	76	48 %
Environmental attribute revenues	14	1	13	1300 %	1	—	— %
Total gross revenues	529	607	(78)	(13)%	387	220	57 %
Net payment relating to Alberta Hydro PPA	—	—	—	— %	(4)	4	(100)%
Revenues[7]	529	607	(78)	(13)%	383	224	58 %
Fuel and purchased power	19	22	(3)	(14)%	16	6	38 %
Gross margin[8]	510	585	(75)	(13)%	367	218	59 %
OM&A	48	55	(7)	(13)%	42	13	31 %
Taxes, other than income taxes	3	3	—	— %	3	—	— %
Adjusted EBITDA[8]	459	527	(68)	(13)%	322	205	64 %
Supplemental Information:							
Gross revenues per MWh							
Alberta Hydro Assets energy ($/MWh)[4][5]	175	197	(22)	(11)%	123	74	60 %
Alberta Hydro Assets ancillary ($/MWh)[3]	67	76	(9)	(12)%	55	21	38 %

(1) In the fourth quarter of 2022, the Company closed the sale of two Hydro assets resulting in a reduction in capacity of 3 MW.

(2) 2022 and 2021 LTA generation revised for consistency with calculation methodology used in 2023.

(3) Ancillary services as described in the AESO Consolidated Authoritative Document Glossary.

(4) Alberta Hydro Assets include 13 hydro facilities on the Bow and North Saskatchewan river systems. Other Hydro assets includes our hydro facilities in BC and Ontario, hydro facilities in Alberta (other than the Alberta Hydro Assets) and transmission revenues.

(5) The Company entered into forward hedges for the first and third quarter of 2023 that are included in the Alberta Hydro Asset revenues.

(6) Other revenue includes revenues from our transmission business and other contractual arrangements, including the flood mitigation agreement with the Government of Alberta and Black Start services.

(7) For details of the adjustments to revenues included in adjusted EBITDA refer to the Additional IFRS and Non-IFRS Measures section of this MD&A.

(8) Adjusted EBITDA and gross margin are not defined and have no standardized meaning under IFRS. Refer to the Additional IFRS and Non-IFRS Measures section of this MD&A.

2023

Revenues for the year ended Dec. 31, 2023, decreased compared to 2022, primarily due to:

- Lower ancillary services volumes due to the AESO procuring lower volumes given its decision to reduce the cumulative volume of imports into Alberta,
- Lower spot power prices and ancillary services prices in the Alberta market and
- Lower production due to lower availability from planned outages at our Alberta Hydro Assets and lower than average water resources, partially offset by
- Realized gains from our hedging strategy for the Alberta Hydro Assets and
- Sales of environmental attributes driven by an increase in emission credit sales.

Adjusted EBITDA for the year ended Dec. 31, 2023, decreased compared to 2022, primarily due to:

- Lower revenues as explained by the factors above.

For further discussion on the Alberta market conditions and pricing, refer to the Alberta Electricity Portfolio section of this MD&A.

2022

Revenues for the year ended Dec. 31, 2022, increased compared to 2021, primarily due to:

- Higher merchant and ancillary service prices and volumes in the Alberta market,
- Higher production and higher availability due to lower planned and unplanned outages at our Alberta Hydro Assets and
- Higher ancillary service volumes due to higher availability and demand.

Adjusted EBITDA for the year ended Dec. 31, 2022, increased compared to 2021, primarily due to:

- Higher revenues as explained by the factors above, partially offset by
- Higher OM&A costs for the year related to increased insurance premiums for updated replacement value coverage and the Company's performance-related incentive accruals.

Wind and Solar

Year ended Dec. 31	2023	2022	Change		2021	Change	
Gross installed capacity (MW)[1]	**2,084**	**1,906**	*178*	*9 %*	1,906	*—*	*— %*
LTA generation (GWh)	**5,387**	**4,950**	*437*	*9 %*	4,345	*605*	*14 %*
Availability (%)	**86.9**	**83.8**	*3.1*	*4 %*	91.9	*(8.1)*	*(9)%*
Production							
Contract production (GWh)	**3,095**	**3,182**	*(87)*	*(3)%*	2,850	*332*	*12 %*
Merchant production (GWh)	**1,148**	**1,066**	*82*	*8 %*	1,048	*18*	*2 %*
Total production (GWh)	**4,243**	**4,248**	*(5)*	*— %*	3,898	*350*	*9 %*
Wind and Solar revenues	**347**	**357**	*(10)*	*(3)%*	320	*37*	*12 %*
Environmental attribute revenues	**26**	**50**	*(24)*	*(48)%*	28	*22*	*79 %*
Revenues[2]	**373**	**407**	*(34)*	*(8)%*	348	*59*	*17 %*
Fuel and purchased power	**30**	**31**	*(1)*	*(3)%*	17	*14*	*82 %*
Carbon compliance	**—**	**1**	*(1)*	*(100)%*	—	*1*	*100 %*
Gross margin[3]	**343**	**375**	*(32)*	*(9)%*	331	*44*	*13 %*
OM&A	**80**	**68**	*12*	*18 %*	59	*9*	*15 %*
Taxes, other than income taxes	**12**	**12**	*—*	*— %*	10	*2*	*20 %*
Net other operating income[2]	**(6)**	**(16)**	*10*	*(63)%*	—	*(16)*	*(100)%*
Adjusted EBITDA[3]	**257**	**311**	*(54)*	*(17)%*	262	*49*	*19 %*
Supplemental information:							
Kent Hills wind rehabilitation expenditures[4]	**87**	**77**	*10*	*13 %*	—	*77*	*100 %*
Insurance proceeds - Kent Hills	**(1)**	**(7)**	*6*	*(86)%*	—	*(7)*	*(100)%*

(1) Gross installed capacity and availability for 2023 includes the 130 MW Garden Plain wind facility that achieved commercial operation in August 2023 and the 48 MW Northern Goldfields solar facilities that achieved commercial operation in November 2023.

(2) For details of the adjustments to revenues and net other operating income included in adjusted EBITDA, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(3) Adjusted EBITDA and gross margin are not defined and have no standardized meaning under IFRS. Refer to the Additional IFRS and Non-IFRS Measures section of this MD&A.

(4) The Kent Hills wind facilities rehabilitation capital expenditures are segregated from the sustaining capital expenditures due to the extraordinary nature of the expenditures.

2023

Revenues for the year ended Dec. 31, 2023, decreased compared to 2022 primarily due to:

- Lower environmental attribute revenues driven by a reduction of offsets and emission credit sales,
- Lower spot power pricing in Alberta and
- Weaker than long-term average wind resource across the operating fleets, partially offset by
- Commercial operation of the Garden Plain wind facility and the Northern Goldfield Solar facilities in the third and fourth quarter, respectively and
- The partial return to service of the Kent Hills wind facilities.

Adjusted EBITDA for the year ended Dec. 31, 2023, decreased compared to the same period in 2022, primarily due to:

- Lower revenues as explained by the factors above,
- Higher OM&A related to salary escalations, higher insurance costs and long-term service agreement escalations and
- Lower liquidated damages recognized at the Windrise wind facility.

2022

Revenues for the year ended Dec. 31, 2022, increased compared to 2021, primarily due to:

- Higher production from the addition of the Windrise wind facility and the acquisition of the North Carolina Solar facilities in the fourth quarter of 2021 and higher wind resources in Eastern Canada,
- Higher realized merchant and spot power pricing in Alberta and
- Higher environmental attribute revenue, partially offset by
- Lower availability as a result of the extended outage at the Kent Hills 1 and 2 wind facilities.

Adjusted EBITDA for the year ended Dec. 31, 2022, increased compared to 2021, primarily due to:

- Higher revenue as explained by the factors above and
- The recognition of liquidated damages recoverable from turbine availability being below the contractual target at the Windrise wind facility, partially offset by
- Higher fuel and purchased power from increases in transmission rates,
- Higher OM&A related to the addition of the Windrise wind and North Carolina Solar facilities during the year and
- A one-time favourable adjustment as a result of the AESO transmission line loss ruling that was included in 2021.

Gas

Year ended Dec. 31	2023	2022	Change		2021	Change	
Gross installed capacity (MW)	3,084	3,084	—	— %	3,084	—	— %
Availability (%)	91.6	94.6	(3.0)	(3)%	85.7	8.9	10 %
Production							
Contract sales volume (GWh)	4,172	3,609	563	16 %	3,622	(13)	— %
Merchant sales volume (GWh)	7,889	7,927	(38)	— %	7,084	843	12 %
Purchased power (GWh)(1)	(188)	(88)	(100)	114 %	(141)	53	(38)%
Total production (GWh)	11,873	11,448	425	4 %	10,565	883	8 %
Revenues(2)	1,525	1,521	4	— %	1,126	395	35 %
Fuel and purchased power(2)	449	637	(188)	(30)%	374	263	70 %
Carbon compliance	112	83	29	35 %	118	(35)	(30)%
Gross margin(3)	964	801	163	20 %	634	167	26 %
OM&A	192	195	(3)	(2)%	173	22	13 %
Taxes, other than income taxes	11	15	(4)	(27)%	13	2	15 %
Net other operating income	(40)	(38)	(2)	5 %	(40)	2	(5)%
Adjusted EBITDA(3)	801	629	172	27 %	488	141	29 %

(1) Power required to fulfill contractual obligations during planned and unplanned outages is included in purchased power.

(2) For details of the adjustments to revenues and fuel and purchased power included in adjusted EBITDA, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(3) Adjusted EBITDA and gross margin are not defined and have no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

2023

Revenues for the year ended Dec. 31, 2023, increased compared to 2022, primarily due to:

- Higher production due to the fleet being available during periods of supply tightness and peak pricing and
- Higher power price hedges, partially offsetting the impact of lower Alberta spot prices, partially offset by
- Lower thermal revenues due to lower steam revenue pricing at the Sarnia facility compared to 2022.

Adjusted EBITDA for the year ended Dec. 31, 2023, increased compared to 2022, primarily due to:

- Lower natural gas commodity costs for the Alberta gas assets and
- Higher revenues explained above, partially offset by
- Higher carbon costs and fuel usage related to production with the utilization of emission credits to settle a portion of the GHG obligation in 2022 and
- Carbon price increases from $50 per tonne to $65 per tonne, impacting our Canadian gas assets.

The Gas fleet significantly exceeded management's expectations for the segment.

2022

Revenues for the year ended Dec. 31, 2022, increased compared to 2021, primarily due to:

- Higher production due to higher availability and dispatch optimization of the Alberta assets,
- Higher realized energy prices through dispatch optimization of our Alberta assets, net of hedging and
- Higher Ontario merchant pricing and steam generation.

Adjusted EBITDA for the year ended Dec. 31, 2022, increased compared to 2021, primarily due to:

- Higher revenues explained above and
- Lower carbon compliance costs due to reductions in GHG emissions as a result of operating exclusively on natural gas in Alberta rather than coal, and the utilization of compliance credits to settle a portion of the GHG obligation, partially offset by
- Increased natural gas consumption on recently converted units and higher natural gas prices,
- Carbon price increases from $35 per tonne to $50 per tonne and
- Higher OM&A due to the Company's performance-related incentive accruals and increased general operating expenses.

Energy Transition

Year ended Dec. 31	2023	2022	Change		2021	Change	
Gross installed capacity (MW)[1]	**671**	**671**	—	— %	1,472	(801)	(54)%
Availability (%)	**79.8**	**77.2**	2.6	3 %	75.3	1.9	3 %
Adjusted availability (%)[2]	**79.8**	**79.0**	0.8	1 %	78.8	0.2	— %
Production							
Contract sales volume (GWh)	**3,329**	**3,329**	—	— %	3,329	—	— %
Merchant sales volume (GWh)	**4,417**	**3,951**	466	12 %	6,052	(2,101)	(35)%
Purchased power (GWh)[3]	**(3,602)**	**(3,706)**	104	(3)%	(3,675)	(31)	1 %
Total production (GWh)	**4,144**	**3,574**	570	16 %	5,706	(2,132)	(37)%
Revenues[4]	**746**	**724**	22	3 %	728	(4)	(1)%
Fuel and purchased power	**557**	**566**	(9)	(2)%	432	134	31 %
Carbon compliance	**—**	**(1)**	1	(100)%	60	(61)	(102)%
Gross margin[5]	**189**	**159**	30	19 %	236	(77)	(33)%
OM&A	**64**	**69**	(5)	(7)%	97	(28)	(29)%
Taxes, other than income taxes	**3**	**4**	(1)	(25)%	6	(2)	(33)%
Adjusted EBITDA[5]	**122**	**86**	36	42 %	133	(47)	(35)%
Supplemental information:							
Highvale mine reclamation spend	**15**	**12**	3	25 %	6	6	100 %
Centralia mine reclamation spend	**13**	**16**	(3)	(19)%	9	7	78 %

(1) The gross installed capacity for 2023 and 2022, excludes Keephills Unit 1 (395 MW retired on Dec. 31, 2021) and Sundance Unit 4 (406 MW retired on March 31, 2022).

(2) Adjusted for dispatch optimization.

(3) All of the power produced by Centralia is sold by the Energy Marketing segment for physical market delivery, which is shown as merchant sales volumes. Power required to fulfil contractual obligations is included in purchased power. Total production from the facility includes the net result of merchant sales volumes and purchased power.

(4) For details of the adjustments to revenues included in adjusted EBITDA refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(5) Adjusted EBITDA and gross margin are not defined and have no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

2023

Revenues for the year ended Dec. 31, 2023, increased compared to 2022, primarily due to:

- Higher production from higher availability due to lower planned and unplanned outages at Centralia Unit 2 and
- Less economic dispatch leading to higher merchant sales volumes, partially offset by
- Lower market prices.

Adjusted EBITDA for the year ended Dec. 31, 2023, increased compared to 2022, primarily due to:

- Higher revenues as explained by the factors above,
- Lower purchased power costs due to lower pricing and increased volumes of production and
- Lower OM&A expenses due to the retirement of Sundance Unit 4 in the first quarter of 2022.

Mine reclamation spend for the year ended Dec. 31, 2023, was consistent compared to 2022.

2022

Revenues for the year ended Dec. 31, 2022, decreased compared to 2021, primarily due to:

- Lower production due to the retirements of the Keephills Unit 1 and Sundance Unit 4, partially offset by
- Increased production from higher availability at Centralia Unit 2 from lower planned and unplanned outages and
- Higher merchant and contract prices at Centralia.

Adjusted EBITDA for the year ended Dec. 31, 2022, decreased compared to 2021 primarily due to:

- Lower revenues as explained by the factors above and
- Higher purchased power costs during outages at Centralia, partially offset by

- Lower OM&A as a result of lower operating costs relating to retirements on the coal fleet in 2021 and
- Lower carbon costs in Alberta related to the retirements on the coal fleet, thereby reducing emissions generated.

Mine reclamation spend for the Highvale and Centralia mines increased compared to 2021, primarily due to the advancement of reclamation activities.

Energy Marketing

Year ended Dec. 31	2023	2022	Change		2021	Change	
Revenues[1]	**152**	**218**	*(66)*	*(30)%*	202	*16*	*8 %*
OM&A	**43**	**35**	*8*	*23 %*	36	*(1)*	*(3)%*
Adjusted EBITDA[2]	**109**	**183**	*(74)*	*(40)%*	166	*17*	*10 %*

(1) For details of the adjustments to revenues included in adjusted EBITDA, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A. Adjusted EBITDA is not defined and has no standardized meaning under IFRS.

(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

2023

Adjusted EBITDA for the year ended Dec. 31, 2023, decreased compared to 2022. This was in line with management's expectations, but lower year over year, primarily due to:

- Lower realized settled trades during the year on market positions in comparison to the prior year and
- OM&A increased mainly due to higher incentives related to revenues before adjustments.

The Company was able to capitalize on volatility in the trading of both physical and financial power and gas products across North American deregulated markets while maintaining the overall risk profile of the business unit.

2022

Adjusted EBITDA for the year ended Dec. 31, 2022, increased compared to 2021, primarily due to:

- Higher realized settled trades during the year on market positions in comparison to prior year and
- The Company capitalizing on short-term volatility in the trading markets without materially changing the risk profile of the business unit.

Corporate

Year ended Dec. 31	2023	2022	Change		2021	Change	
OM&A	**115**	**101**	*14*	*14%*	84	*17*	*20%*
Taxes, other than income taxes	**1**	**1**	—	*—%*	1	—	*—%*
Adjusted EBITDA[1]	**(116)**	**(102)**	*(14)*	*14%*	(85)	*(17)*	*20%*

(1) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

2023

Adjusted EBITDA for the year ended Dec. 31, 2023, decreased compared to 2022, primarily due to:

- Increased spending to support strategic and growth initiatives,
- Higher costs associated with the relocation of the Company's head office and
- Increased costs due to inflationary pressures.

2022

Adjusted EBITDA for the year ended Dec. 31, 2022, decreased compared to 2021, primarily due to:

- Higher incentive accruals reflecting the Company's performance;
- No additional receipts of Canada Emergency Wage Subsidy proceeds as occurred in 2021 and
- Higher losses on the total return swap.

Performance by Segment with Supplemental Geographical Information

The following table provides adjusted EBITDA performance of our facilities across the regions we operate in:

Year ended Dec. 31, 2023	Hydro	Wind & Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Alberta	451	77	571	(10)	109	(116)	1,082
Canada, excluding Alberta	8	95	89	—	—	—	192
US	—	84	10	132	—	—	226
Australia	—	1	131	—	—	—	132
Adjusted EBITDA(1)	**459**	**257**	**801**	**122**	**109**	**(116)**	**1,632**
Earnings before income taxes							**880**

Year ended Dec. 31, 2022	Hydro	Wind & Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Alberta	515	114	404	(18)	183	(102)	1,096
Canada, excluding Alberta	12	106	87	—	—	—	205
US	—	91	8	104	—	—	203
Australia	—	—	130	—	—	—	130
Adjusted EBITDA(1)	527	311	629	86	183	(102)	1,634
Earnings before income taxes							353

(1) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Presenting this from period to period provides management and investors with the ability to evaluate earnings (loss) trends more readily in comparison with prior periods' results. Refer to the Segmented Financial Performance and Operating Results section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS. Also, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Optimization of the Alberta Portfolio

Our merchant exposure is primarily in Alberta, where 53 per cent of our capacity is located, and 75 per cent of our Alberta assets are available to participate in the merchant market. Our portfolio of merchant assets in Alberta consists of hydro facilities, wind facilities, a battery storage facility and natural gas generation facilities.

Generating capacity in Alberta is subject to market forces, rather than rate regulation. Power from commercial generation is cleared through a wholesale electricity market. Power is dispatched in accordance with an economic merit order administered by the AESO, based upon offers by generators to sell power in the real-time energy-only market. Our merchant Alberta fleet operates under this framework and we internally manage our offers to sell power.

Optimization of portfolio performance in the Alberta merchant market is driven by the diversity of fuel types and enables portfolio management. It also provides us with capacity that can be monetized as ancillary services or dispatched into the energy market during times of supply tightness. A significant portion of the thermal generation capacity in the portfolio has been hedged to provide cash flow certainty. The Company's hedging strategy includes maintaining a significant base of commercial and industrial customers and is supplemented with financial hedges. In 2023, 78 per cent of our energy production in Alberta was sold under long-term contracts or fixed price hedges.

The Alberta hydro fleet provides ancillary services and grid reliability products such as Black Start service in the event of a system-wide blackout in the province and drought mitigation by systematically regulating river flows. Our Alberta wind and hydro fleets provide a steady stream of environmental credits to meet ESG goals.

During 2023, the Company entered into a definitive share purchase agreement relating to Heartland Generation Ltd. and Alberta Power (2000) Ltd. (collectively "Heartland") and expects to close the transaction in the first half of 2024, subject to certain customary closing conditions being met. The Heartland acquisition will further expand our portfolio capabilities. The fast-ramping nature of certain of the Heartland units will be ideally positioned to capture expected price swings and periodic higher realized prices in the Alberta market.

	2023					2022					2021				
Year ended Dec. 31	Hydro	Wind & Solar	Gas	Energy Transition	Total	Hydro	Wind & Solar	Gas	Energy Transition	Total	Hydro	Wind & Solar	Gas	Energy Transition	Total
Gross installed capacity (MW)	834	766	1,960	—	3,560	834	636	1,960	—	3,430	834	636	1,960	801	4,231
Total production (GWh)	1,492	1,907	8,360	—	11,759	1,665	1,686	8,106	19	11,476	1,586	1,319	7,281	2,591	12,777
Contract production (GWh)	—	774	861	—	1,635	—	620	526	—	1,146	—	271	509	—	780
Merchant production (GWh)	1,492	1,133	7,499	—	10,124	1,665	1,066	7,580	19	10,330	1,586	1,048	6,772	2,591	11,997
Hedged production (GWh)	378	—	7,172	—	7,550	—	—	7,228	—	7,228	—	—	6,992	—	6,992
Production contracted or hedged (%)	25%	41%	96%	—%	78%	—%	37%	96%	—%	73%	—%	21%	103%	—%	61%
Revenues[(1)] ($)	509	130	1,083	5	1,727	583	155	989	6	1,733	358	97	674	257	1,386
Fuel and purchased power ($)	17	20	336	—	373	18	21	442	5	486	13	9	258	92	372
Carbon compliance ($)	—	—	106	—	106	—	1	70	(1)	70	—	—	96	60	156
Gross margin ($)	492	110	641	5	1,248	565	133	477	2	1,177	345	88	320	105	858

(1) Revenues have been adjusted to exclude the impact of unrealized mark-to-market gains or losses and to include realized gains and losses on closed exchange positions.

Total production for the year ended Dec. 31, 2023, was 11,759 GWh compared to 11,476 GWh of electricity in 2022. The increase of 283 GWh, or 2 per cent, was primarily due to:

- The commercial operation of the Garden Plain wind facility in the third quarter of 2023,
- Higher production from our Gas assets due to strong market conditions in the first half of 2023, partially offset by
- Lower water resources in the Alberta Hydro assets.

Hedged production for the year ended Dec. 31, 2023, increased compared to 2022, primarily due to:

- The opportunity to secure additional margins with strategic hedges for the hydro assets.

Gross margin for the year ended Dec. 31, 2023, was $1,248 million compared to $1,177 million in 2022. The increase of $71 million, or 6 per cent, was primarily due to:

- Higher power price hedges, partially offsetting the impacts of lower Alberta spot prices and
- Lower natural gas prices compared to 2022, partially offset by
- Lower ancillary services revenues due to the AESO procuring lower volumes given its decision to reduce the cumulative volume of imports into Alberta.

The following table provides information for the Company's Alberta electricity portfolio:

Year ended Dec. 31, 2023	2023	2022	2021
Alberta Market			
Spot power price average per MWh	**134**	162	102
Natural gas price (AECO) per GJ	**2.54**	5.08	3.39
Carbon compliance price per tonne	**65**	50	40
Alberta Portfolio Results			
Realized merchant power price per MWh(1)	**136**	126	91
Hydro energy spot power price per MWh	**175**	197	122
Hydro ancillary spot price per MWh	**67**	76	55
Wind energy spot power price per MWh	**73**	90	63
Gas and Energy Transition spot power price per MWh	**162**	194	114
Hedged power price average per MWh	**111**	86	72
Hedged volume (GWh)	**7,550**	7,228	6,992
Fuel and purchased power per MWh(2)	**45**	60	38
Carbon compliance cost per MWh(2)	**13**	9	16

(1) Realized merchant power price for the Alberta electricity portfolio is the average price realized as a result of the Company's merchant power sales and portfolio optimization activities (excluding assets under long-term contract and ancillary revenues) divided by total merchant GWh produced.

(2) Fuel and purchased power per MWh and carbon compliance cost per MWh are calculated on production from carbon-emitting generation in the Gas and Energy Transition segments, and carbon compliance cost per MWh includes emission credits used to settle a portion of GHG carbon pricing obligations.

The average spot power price per MWh for the year ended Dec. 31, 2023 decreased from $162 per MWh in 2022 to $134 per MWh in 2023, primarily due to:

- Moderate temperatures in the last six months of the year compared with the prior year;
- Higher total renewable generation in the Alberta market from new wind and solar facilities and higher wind resources during the fourth quarter of 2023; and
- Lower natural gas prices.

Realized merchant power price per MWh of production for the year ended Dec. 31, 2023, increased by $10 per MWh, compared to 2022, primarily due to:

- Optimization of our available capacity across all fuel types; and
- Higher hedge prices compared to the prior year.

Fuel and purchased power cost per MWh for the year ended Dec. 31, 2023, decreased by $15 per MWh, compared to 2022, primarily due to lower natural gas prices.

Carbon compliance cost per MWh of production for the year ended Dec. 31, 2023, increased by $4 per MWh, compared to 2022, primarily due to:

- Carbon compliance prices increasing from $50 per tonne in 2022 to $65 per tonne in 2023; and
- No utilization of emission credits to settle the GHG obligation during the year. In the prior year, the Company used emission credits to settle a portion of the carbon compliance obligation resulting in a lower carbon cost per MWh.

Fourth Quarter Highlights

The Hydro, Wind and Gas facilities in the Alberta electricity portfolio in the fourth quarter of 2022 had high availability during periods of peak pricing, which resulted from extreme cold weather and periods of province-wide planned and unplanned outages resulting in exceptional financial performance during the quarter. The Company did not experience the same weather conditions in the fourth quarter of 2023; with the weather being relatively mild compared to the fourth quarter of 2022.

Consolidated Financial Highlights

Three months ended Dec. 31	2023	2022
Operational information		
Adjusted availability (%)	**86.9**	89.5
Production (GWh)	**5,783**	6,005
Select financial information		
Revenues	**624**	854
Earnings (loss) before income taxes	**(35)**	7
Adjusted EBITDA(1)	**289**	541
Net (loss) attributable to common shareholders	**(84)**	(163)
Cash flows		
Cash flow from operating activities	**310**	351
Funds from operations(1)	**229**	459
Free cash flow(1)	**121**	315
Per share		
Weighted average number of common shares outstanding	**308**	269
Net (loss) per share attributable to common shareholders, basic and diluted	**(0.27)**	(0.61)
Dividends declared per common share	**0.12**	0.11
Funds from operations per share(1)(2)	**0.74**	1.71
Free cash flow per share(1)(2)	**0.39**	1.17

(1) These items are not defined and have no standardized meaning under IFRS. Refer to the Segmented Financial Performance and Operating Results section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS. Also, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(2) FFO per share and FCF per share are calculated using the weighted average number of common shares outstanding during the period. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for the purpose of these non-IFRS ratios.

Operating Performance

Adjusted Availability

The following table provides adjusted availability (%) by segment:

Three months ended Dec. 31	2023	2022
Hydro	**76.6**	96.8
Wind and Solar	**90.3**	85.7
Gas	**89.5**	92.8
Energy Transition	**79.6**	76.4
Adjusted availability (%)	**86.9**	89.5

Adjusted availability for the three months ended Dec. 31, 2023, was 86.9 per cent compared to 89.5 per cent for the same period in 2022, primarily due to:

- Planned outages in the Gas segment and Hydro segment, partially offset by
- Higher availability for the Wind and Solar segment, mainly due to the partial return to service of the Kent Hills wind facilities and
- Lower unplanned outages in the Energy Transition segment.

Production and Long-Term Average Generation

	2023			2022		
Three months ended Dec. 31	**Actual production (GWh)**	**LTA generation (GWh)**	**Production as a % of LTA**	**Actual production (GWh)**	**LTA generation (GWh)**	**Production as a % of LTA**
Hydro	**326**	**447**	**73%**	344	435	79%
Wind and Solar	**1,479**	**1,621**	**91%**	1,222	1,499	82%
Gas	**2,892**			3,375		
Energy Transition	**1,086**			1,064		
Total	**5,783**			6,005		

Production for the three months ended Dec. 31, 2023, was 5,783 GWh compared to 6,005 GWh for the same period in 2022. The decrease was primarily due to:

- Lower dispatch of the Alberta Gas assets due to warmer temperatures and
- Lower availability, partially offset by
- Higher production in the Wind and Solar segment with the addition of the Garden Plain wind facility.

During the fourth quarter of 2023, weather impacts were relatively mild compared to the prior period, as the Company did not experience the same weather conditions as the fourth quarter of 2022, which had extreme cold weather in Alberta, resulting in periods of exceptional peak pricing in 2022.

Financial Performance review on Consolidated Information

Three months ended Dec. 31	2023	2022
Revenues	**624**	854
Fuel and purchased power	**278**	446
Carbon compliance	**27**	27
Operations, maintenance and administration	**150**	157
Depreciation and amortization	**132**	188
Gain on sale of assets and other	**—**	46
Earnings (loss) before income taxes	**(35)**	7
Income tax expense	**19**	89
Net loss attributable to common shareholders	**(84)**	(163)
Net earnings attributable to non-controlling interests	**5**	56

Current Year Variance Analysis (Fourth quarter 2023 versus 2022)

Revenues for the three months ended Dec. 31, 2023, decreased by $230 million, or 27 per cent, compared to the same period in 2022, primarily due to:

- Lower merchant sales due to lower spot power prices and production in Alberta and
- Lower realized ancillary services prices and volumes in the Hydro segment, partially offset by
- Higher realized and unrealized gains from hedging and derivative positions across the segments.

Fuel and purchased power costs for the three months ended Dec. 31, 2023, decreased by $168 million, or 38 per cent, compared to the same period in 2022, primarily due to:

- Lower natural gas commodity costs and
- Lower consumption of natural gas within our Gas segment.

Carbon compliance costs for the three months ended Dec. 31, 2023, were consistent with the same period in 2022 due to:

- Carbon price increases from $50 per tonne to $65 per tonne, offset by
- Reduced production volumes.

OM&A expenses for the three months ended Dec. 31, 2023, decreased by $7 million, or 4 per cent, compared to the same period in 2022, primarily due to:

- Lower incentive accruals in line with the Company's performance in comparison to the Company's exceptional performance in the fourth quarter of 2022, partially offset by
- The write-down of parts and material inventory for the gas facilities.

Depreciation and amortization for the three months ended Dec. 31, 2023, decreased by $56 million, or 30 per cent, compared to the same period in 2022, primarily due to:

- Revisions to useful lives on certain facilities, partially offset by
- Commercial operation of new facilities.

Gain on sale of assets and other for the three months ended Dec. 31, 2023, decreased by $46 million, or 100 per cent, compared to the same period in 2022, primarily due to the sale of certain gas generation assets in 2022.

Loss before income taxes totalling $35 million, decreased by $42 million, or 600 per cent, compared to earnings before income taxes of $7 million in 2022, due to the above noted items.

Income tax expense for the three months ended Dec. 31, 2023, decreased by $70 million, or 79 per cent, compared to 2022, due to lower earnings before tax in 2023 and the reduction of non-deductible expenses in the U.S.

Net loss attributable to common shareholders in the three months ended Dec. 31, 2023 was $84 million compared to a net loss of $163 million in the same period of 2022, an improvement of $79 million, or 48 percent, primarily due to the above noted items.

Net earnings attributable to non-controlling interests for the three months ended Dec. 31, 2023, decreased by $51 million, or 91 per cent, compared to the same period in 2022, primarily due to lower net earnings for TA Cogen and the acquisition of TransAlta Renewables on Oct. 5, 2023.

Segmented Financial Performance and Operating Results for the Fourth Quarter

A summary of our adjusted EBITDA by segment and earnings (loss) before income taxes for the three months ended Dec. 31, 2023, and 2022 is as follows:

	Adjusted EBITDA[(1)]	
Three months ended Dec. 31	**2023**	**2022**
Hydro	**56**	133
Wind and Solar	**82**	92
Gas	**141**	264
Energy Transition	**26**	19
Energy Marketing	**14**	63
Corporate	**(30)**	(30)
Total adjusted EBITDA[(1)]	**289**	541
Earnings (loss) before income taxes	**(35)**	7

(1) This item is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

The major factors impacting adjusted EBITDA for the three months ended Dec. 31, 2023, are summarized in the following table:

	Three months ended Dec. 31
Adjusted EBITDA for the three months ended Dec. 31, 2022	541
Hydro: lower due to decreased revenues from lower merchant and ancillary prices in the Alberta market and lower ancillary services volumes.	(77)
Wind and Solar: lower due to lower merchant pricing in Alberta, lower wind resource in Eastern Canada and the US and higher OM&A due to new long-term service agreements, partially offset by higher revenues related to the partial return to service of the Kent Hills facilities and the addition of the Garden Plain wind facility and Northern Goldfields solar facilities.	(10)
Gas: lower due to lower realized prices and production volume in the Alberta market, lower thermal revenues due to lower steam revenue pricing at the Sarnia facility compared to 2022, and higher OM&A with the inventory writedown at the Sundance and Keephills 2 facilities.	(123)
Energy Transition: higher due to higher production due to lower unplanned outages, partially offset by lower revenues as a result of lower market prices.	7
Energy Marketing: lower realized settled trades during the fourth quarter on market positions in comparison to the prior period in 2022.	(49)
Corporate: consistent with the same period in 2022.	—
Adjusted EBITDA(1) for the three months ended Dec. 31, 2023	**289**

(1) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

FCF for the three months ended Dec. 31, 2023, decreased by $194 million or 62 per cent, compared to the same period in 2022.

	Three months ended Dec. 31
FCF for the three months ended Dec. 31, 2022	315
Lower adjusted EBITDA: lower FCF due to the items noted above.	(252)
Lower distributions paid to subsidiaries' non-controlling interests: lower net earnings in TA Cogen and no dividends paid to TransAlta Renewables shareholders resulting in higher FCF.	42
Other(1)	16
FCF(2) for the three months ended Dec. 31, 2023	**121**

(1) Refer to the Reconciliation of Cash Flow from Operations to FFO and FCF section tables in this MD&A for more details.

(2) FCF is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Selected Quarterly Information

Our results are seasonal due to the nature of the electricity market and related fuel costs. Higher maintenance costs are often incurred in the spring and fall when electricity prices are expected to be lower; electricity prices generally increase in the peak winter and summer months in our main markets due to increased heating and cooling loads. Margins are also typically impacted in the second quarter due to the volume of hydro production resulting from spring runoff and rainfall in the Pacific Northwest, which impacts production at Centralia. Typically, hydroelectric facilities generate most of their electricity and revenues during the spring months when melting snow starts feeding watersheds and rivers. Inversely, wind speeds are historically greater during the cold winter months and lower in the warm summer months.

	Q1 2023	Q2 2023	Q3 2023	Q4 2023
Revenues	1,089	625	1,017	**624**
Earnings (loss) before income taxes	383	79	453	**(35)**
Net earnings (loss) attributable to common shareholders	294	62	372	**(84)**
Net earnings (loss) per share attributable to common shareholders, basic and diluted[1]	1.10	0.23	1.41	**(0.27)**
Cash flow from operating activities	462	11	681	**310**

	Q1 2022	Q2 2022	Q3 2022	Q4 2022
Revenues	735	458	929	854
Earnings (loss) before income taxes	242	(22)	126	7
Net earnings (loss) attributable to common shareholders	186	(80)	61	(163)
Net earnings (loss) per share attributable to common shareholders, basic and diluted[1]	0.69	(0.30)	0.23	(0.61)
Cash flow from (used in) operating activities[2]	451	(129)	204	351

(1) Basic and diluted earnings (loss) per share attributable to common shareholders is calculated in each period using the basic and diluted weighted average common shares outstanding during the period, respectively. As a result, the sum of the earnings (loss) per share for the four quarters making up the calendar year may sometimes differ from the annual earnings (loss) per share.

(2) The cash flow used in operating activities for the second quarter of 2022 was negative due to unfavourable changes in working capital mainly due to movements in our collateral accounts related to higher commodity prices and volatility in the markets.

Net earnings (loss) attributable to common shareholders over the prior eight quarters has also been impacted by the following variations and events:

- Higher revenues arising from higher overall availability during periods of peak pricing and higher power prices in Alberta in the second, third and fourth quarters of 2022 and the first and second quarters of 2023;
- Lower natural gas pricing in 2023 and higher natural gas pricing in 2022;
- Lower carbon costs in 2022 were realized as the Company utilized emission credits to settle a portion of our GHG obligation in the second quarter of 2022. In 2023, the Company settled its carbon obligation with cash. Higher carbon costs in the first three quarters of 2023 were due to higher carbon price per tonne and were also due to higher production in the second quarter of 2023;
- The continued extended outage of the Kent Hills 1 and 2 wind facilities from the first quarter of 2022 through to the third quarter of 2023. The facilities were partially returned to service in the fourth quarter of 2023, with all turbines now commissioned and the remediation project completed in the first quarter of 2024;
- The effects of asset impairment reversals recognized in the first, second and third quarters of 2023 and the effects of asset impairment charges and reversals during all periods shown;
- The effects of changes in decommissioning provisions for retired assets from changes in estimated cash flows and discount rates in all periods shown, and changes in useful lives, recognized in the third quarter of 2022 and the third and fourth quarters of 2023;
- Insurance proceeds for the single tower failure at Kent Hills wind facilities of $7 million recognized in the second quarter of 2022;
- Liquidated damages recoverable from turbine availability being below the contractual target at the Windrise wind facility recorded in each quarter in 2022 and in each quarter in 2023;
- Sundance Unit 4 being retired in the first quarter of 2022;
- Commissioning of the Garden Plain wind facility in the third quarter of 2023 and the Northern Goldfields solar facilities in the fourth quarter of 2023;
- Gains relating to the sale of assets being recognized in the fourth quarter of 2022;
- Fluctuations in the Canadian dollar relative to the US dollar resulting in foreign exchange gains and losses on our US-denominated long-term debt balances not designated as hedges; and
- Fluctuations in current and deferred tax expense with earnings before tax across the quarters. Deferred tax expense decreased from 2022 mainly due to a lower non-deductible tax adjustment relating to the US along with a deferred tax recovery of a previous derecognition of Canadian tax assets.

Strategy and Capability to Deliver Results

Our strategic focus is to invest in clean electricity solutions that meet the needs and objectives of our customers and communities. We invest in a disciplined and prudent manner to deliver appropriately risk-adjusted returns to our shareholders. To support this strategy, we maintain a growing pipeline of project opportunities focused on hydro, wind, solar, energy storage and low emissions gas generation.

In 2021, we set out clear targets under the Clean Electricity Growth Plan. These targets included delivering 2 GW of incremental renewable capacity with a target capital investment of $3.6 billion in order to drive additional cumulative annual EBITDA of $315 million from new growth projects. Over the last two years, the Company achieved over 40 per cent of that original target by adding 800 MW of new capacity, together with the transmission expansion project for BHP Nickel West.

In 2023, given the market challenges of rising equipment and capital costs, we remained disciplined and patient with our greenfield efforts and shifted our focus towards priorities of simplification, contracted renewables and flexible generation. We looked to two strategic acquisitions that would position the Company well for the future, TransAlta Renewables and Heartland Generation Ltd.

We deployed $1.3 billion toward the acquisition of TransAlta Renewables which provided economic contribution from an incremental 1.2 GW of generating capacity, increasing the proportionate EBITDA and contractedness of the Company.

We also entered into a definitive share purchase agreement to acquire Heartland Generation Ltd. for an estimated total cost of $658 million. The acquisition will competitively position the Company in response to the changing dynamics in Alberta, given the expected significant increase in renewables and other large baseload generation coming online in the next several years in the highly dynamic and shifting electricity landscape in the province.

In 2023, our growth and execution teams progressed construction on new facilities, in all three of our core geographies, through one of the largest construction programs that the Company has ever undertaken. The fully contracted 130 MW Garden Plain and 48 MW Northern Goldfields solar and battery storage facilities reached commercial operation, adding $21-$23 million in incremental EBITDA. The 300 MW White Rock East and the White Rock West projects and the 200 MW Horizon Hill wind project are expected to reach commercial operation in the first quarter of 2024, adding $76-$82 million and $41-$44 million, respectively, in incremental EBITDA.

Strategic Priorities and Clean Electricity Growth Plan to 2028

On Nov. 21, 2023, the Company updated its five-year strategic growth targets and Clean Electricity Growth Plan. The Company established six strategic priorities to focus our path from 2024 to 2028. They are outlined below and include goals for growth, investment and ESG priorities.

The Company's growth targets include adding up to 1.75 GW of new generating capacity to the Company's fleet while targeting cumulative annual EBITDA from new growth of $350 million by investing approximately $3.5 billion to develop, construct and acquire new assets through 2024 to the end of 2028. The growth will focus on customer-centered renewables and storage through the execution of its current 5.3 GW development pipeline that it plans to expand to reach 10 GW by 2028.

We expect the Company's adjusted EBITDA generated from renewable sources, including hydro, wind and solar technologies, to increase to 70 per cent by the end of 2028. The Clean Electricity Growth Plan will largely be funded from current cash balances, cash generated from operations and debt financing.

Our investment focus to 2028 will focus on renewables and storage, but may also include efficient and flexible natural gas generation and new technology. The Company has a long-term decarbonization goal of net-zero by 2045.

Our current progress towards achieving these strategic targets is summarized below:

Strategic Targets 2024 to 2028

Goals	Target	Results	Comments
Optimize Alberta portfolio	Continue to optimize our existing asset base and maximize the value of our hydro fleet in Alberta.	On Track	The acquisition of Heartland will add 1,844 MW of complementary flexible capacity to the Alberta portfolio including contracted cogeneration, peaking generation, transmission capacity and development opportunities in hydrogen.
Execute Clean Electricity Growth Plan	Deliver up to 1.75 GW of renewable capacity with an estimated capital investment of $3.5 billion by the end of 2028.	On Track	The Company is currently advancing 418 MW of advanced-stage projects towards final investment decision in 2024.
	Deliver incremental average annual EBITDA of $350 million by the end of 2028.	On Track	In 2024, the Company plans to make investment decisions on new projects that will produce at least $80 million in incremental EBITDA.
	Expand the Company's development pipeline to 10 GW by the end of 2028.	On Track	In 2024, The Company plans to add an additional 1,500 MW to its development pipeline to further support our Clean Electricity Growth Plan.
Selective Expansion of Flexible Generation and Reliability Assets	Selectively expand our portfolio offerings in flexible generation and reliability assets such as peaking generation and short-term and long-term storage.	On Track	The Company plans to selectively invest in peaking generation and battery storage assets to optimize our portfolio. The acquisition of Heartland will add 387 MW of peaking gas capacity to our portfolio, the peaking assets will be optimized by the Company to address increasing intermittency in Alberta.
Maintain Our Financial Strength and Capital Allocation Discipline	Deliver strong cash flow from our existing portfolio to allocate towards our funding priorities including growth, dividends, debt repayments and share repurchases.	On Track	The Company had liquidity of $1.7 billion as at Dec. 31, 2023. The Company increased the annual common share dividend by 9 per cent to $0.24 per year effective April 1, 2024. In 2024, the Company announced that it intends to repurchase up to $150 million of common shares. The increased annual common share dividend, along with the share repurchase commitment, will represent a return of up to approximately 40 per cent of the midpoint of our 2024 FCF guidance to shareholders.
Define the Next Generation of Power Solutions	Meet the needs of our customers and communities through the implementation of innovative electricity solutions and parallel investments in new complementary sectors by the end of 2028.	On Track	The Company established an Energy Innovation team to progress our goals in this area. The team has completed an equity investment in Ekona Power Inc. ("Ekona"), an early-stage hydrogen production company, in order to pursue commercialization of low cost, net-zero aligned hydrogen. The Company also committed to invest US$25 million over the next four years in the Energy Impact Partners Frontier Fund, which provides a portfolio approach to investing in emerging technologies focused on net-zero emissions. In total, the Company invested US$12 million to this fund as at Dec. 31, 2023.
Lead in ESG and Market Policy Development	Actively participate in policy development to ensure the electricity that we provide contributes to emissions reduction, grid reliability and competitive energy prices to enable the successful evolution of the markets in which we operate and compete.	On Track	The Company is actively engaging the Government of Canada and Government of Alberta on the proposed federal Clean Electricity Regulations, as well as electricity market and renewable approval changes under review in Alberta. This includes participation in the AESO's Executive Working Group and the Canada Electricity Advisory Council. TransAlta's input is focused on how to achieve emissions reductions while maintaining reliability and affordability. The Company continues to work with the Government of Canada on the design details of the investment tax credits and clean technology funding provided through the Government of Canada, as well as exploring funding opportunities through the Government of Alberta.

Advanced-Stage Development

These projects have detailed engineering, advanced positions in the interconnection queue and/or are progressing offtake opportunities. Projects in advanced-stage development are progressing towards final investment decision and do not have final approval from the Board of Directors at time of reporting. The following table shows the pipeline of future growth projects currently under advanced-stage development:

Project	Type	Region	Target investment date	MW	Estimated spend	Average annual EBITDA[1]
Tempest	Wind	Alberta	2024	100	$260-$280	$22-$26
SCE Capacity Expansion	Gas	Western Australia	2024	94	AU$210-AU$230	AU$28-AU$32
WaterCharger	Battery Storage	Alberta	2024	180	$160-$180[2]	$15-$17
Pinnacle 1 & 2	Gas	Alberta	2024	44	$65-$75	$13-$15
Total[3]				**418**	**$740 - $813**	**$82 - $94**

(1) This item is not defined, has no standardized meaning under IFRS and is forward-looking. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further discussion.

(2) Estimated spend is net of government funding and anticipated tax credits.

(3) Total expected spending and average annual EBITDA was converted using a Canadian dollar forward exchange rate for 2023.

Early-Stage Development

These projects are in the early stages and may or may not move ahead. Generally, these projects will have:

- Collected meteorological data;
- Begun securing land control;
- Started environmental studies;
- Confirmed appropriate access to transmission; and
- Started preliminary permitting and other regulatory approval processes.

The following table shows the pipeline of future growth projects currently under early-stage development:

Project	Type	Region	Potential investment date(1)	MW
Canada				
Riplinger Wind	Wind	Alberta	2025	300
Sunhills Solar	Solar	Alberta	2025	170
McNeil Solar	Solar	Alberta	2025	57
New Brunswick Battery	Battery	New Brunswick	2025	10
Tent Mountain Pumped Storage(2)	Hydro	Alberta	2026	160
Provost	Wind	Alberta	2026	170
Antelope Coulee	Wind	Saskatchewan	2027+	200
Red Rock	Wind	Alberta	2027	100
Willow Creek 1	Wind	Alberta	2027	70
Willow Creek 2	Wind	Alberta	2027	70
Other Canadian Opportunities	Wind	Various	2026+	190
Brazeau Pumped Hydro	Hydro	Alberta	TBD	300-900
Alberta Thermal Redevelopment(3)	Various	Alberta	TBD	250-500
		Total		**2,047 - 2,897**
United States				
Monument Road	Wind	Nebraska	2025	152
Swan Creek	Wind	Nebraska	2025	126
Dos Rios	Wind	Oklahoma	2025	242
Cotton Belle 1	Solar	Texas	2025	104
Cotton Belle 2	Solar	Texas	2025	81
Square Top	Solar	Oklahoma	2026	195
Old Town	Wind	Illinois	2026	185
Canadian River	Wind	Oklahoma	2026	250
Prairie Violet	Wind	Illinois	2026	130
Quick Draw	Wind	Texas	2026	174
Big Timber	Wind	Pennsylvania	2026	50
Trapper Valley	Wind	Wyoming	2027	225
Wild Waters	Wind	Minnesota	2027+	40
Coolspring	Wind	Pennsylvania	2027+	120
Other US Opportunities	Wind	Various	2026+	144
Centralia Site Redevelopment(3)	Various	Washington	TBD	250-500
		Total		**2,468 - 2,718**
Australia				
Boodarie Solar	Solar	Western Australia	2024	50
Southern Cross Energy	Wind and Solar	Western Australia	TBD	120
Other Australian Opportunities	Gas, Solar, Transmission	Western Australia	2024+	230
		Total		**400**
Canada, United States and Australia		**Total**		**4,915 - 6,015**

(1) Potential investment date is to be determined ("TBD").

(2) This represents the Company's 50 per cent interest in Tent Mountain. See the Significant and Subsequent Events section of this MD&A for more details.

(3) The Company is currently evaluating redevelopment opportunities at these brownfield sites.

Projects under Construction

The following projects have been approved by the Board of Directors, have executed PPAs and are currently under construction or in the process of being commissioned. The projects under construction will be financed through existing liquidity in the near term. We will continue to explore permanent financing solutions on an asset-by-asset basis.

We are continually monitoring the timing and costs on our projects under construction. Our US projects have experienced schedule delays and increased costs attributable to complexities relating to transmission interconnections and wind turbine erection. The 300 MW White Rock wind projects and the 200 MW Horizon Hill wind project transmission lines are fully energized. The projects are expected to achieve commercial operation in the first quarter of 2024.

				Total project (millions)					
Project	**Type**	**Region**	**MW**	**Estimated spend**	**Spent to date**	**Target completion date**	**PPA Term[1]**	**Average annual EBITDA[2]**	**Status**
United States									
White Rock	**Wind**	OK	300	US$510 — US$530	US$477	Q1 2024	—	US$53-US$57	• Long-term PPAs executed • Installation/assembly complete • Final stages of commissioning underway
Horizon Hill	**Wind**	OK	200	US$330 — US$340	US$307	Q1 2024	—	US$31-US$33	• Long-term PPA executed • Installation/assembly complete • Final stages of commissioning underway
Australia									
Mount Keith 132kV Expansion	**Transmission**	WA	n/a	AU$54 — AU$57	AU$45	Q1 2024	15	AU$6 - AU$7	• Installation/assembly complete • Final stages of commissioning underway
Mount Keith West Network Upgrade	**Transmission**	WA	n/a	AU$37 — AU$40	AU$12	Q2 2025	14	AU$6 - AU$7	• Major equipment orders placed • Detailed design and execution planning underway • On track to be completed on schedule
Total[3]			**500**	**$1,228 — $1,274**	**1,360**			**$125 - $135**	

(1) The PPA term is confidential for the White Rock wind projects and Horizon Hill wind project.

(2) This item is not defined and has no standardized meaning under IFRS and is forward-looking. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further discussion.

(3) Total expected spending and average annual EBITDA were converted using a Canadian dollar forward exchange rate for 2023. Spend to date was converted using the period-end closing rate.

Financial Position

The following table highlights significant changes in the Consolidated Statements of Financial Position from Dec. 31, 2022, to Dec. 31, 2023:

	Dec. 31, 2023	Dec. 31, 2022	Increase/(decrease)
Assets			
Current assets			
Cash and cash equivalents	**348**	1,134	(786)
Trade and other receivables	**807**	1,589	(782)
Risk management assets	**151**	709	(558)
Other current assets(1)	**274**	282	(8)
Total current assets	**1,580**	3,714	(2,134)
Non-current assets			
Risk management assets	**52**	161	(109)
Property, plant and equipment, net	**5,714**	5,556	158
Long-term portion of finance lease receivable	**171**	129	42
Other non-current assets(2)	**1,142**	1,181	(39)
Total non-current assets	**7,079**	7,027	52
Total assets	**8,659**	10,741	(2,082)
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	**797**	1,346	(549)
Risk management liabilities	**314**	1,129	(815)
Income taxes payable	**9**	73	(64)
Credit facilities, long-term debt and lease liabilities	**532**	178	354
Other current liabilities(3)	**90**	162	(72)
Total current liabilities	**1,742**	2,888	(1,146)
Non-current liabilities			
Credit facilities, long-term debt and lease liabilities	**2,934**	3,475	(541)
Risk management liabilities (long-term)	**274**	333	(59)
Defined benefit obligation and other long-term liabilities	**251**	294	(43)
Deferred income tax liabilities	**386**	352	34
Other non-current liabilities(4)	**1,408**	1,410	(2)
Total non-current liabilities	**5,253**	5,864	(611)
Total liabilities	**6,995**	8,752	(1,757)
Equity			
Equity attributable to shareholders	**1,537**	1,110	427
Non-controlling interests	**127**	879	(752)
Total equity	**1,664**	1,989	(325)
Total liabilities and equity	**8,659**	10,741	(2,082)

(1) Includes restricted cash, prepaid expenses and other, and inventory.

(2) Includes investments, right-of-use assets, intangible assets, goodwill, deferred income tax assets and other assets.

(3) Includes bank overdraft, current portion of decommissioning and other provisions, current portion of contract liabilities and dividends payable.

(4) Includes exchangeable securities, long-term decommissioning and other provisions and contract liabilities.

(5) Significant changes in TransAlta's Consolidated Statements of Financial Position were as follows:

Working Capital

The deficit of current assets over current liabilities, including the current portion of long-term debt and lease liabilities, was $162 million as at Dec. 31, 2023 (Dec. 31, 2022 – excess of current assets over current liabilities of $826 million), primarily as a result of the $400 million Term Facility being reclassified from long-term to current liabilities in the period as it is due to be repaid in September 2024, along with lower receivables and collateral provided in the Energy Marketing segment due to reduced volatility in the market and market prices.

Current assets decreased by $2,134 million to $1,580 million as at Dec. 31, 2023, from $3,714 million as at Dec. 31, 2022, primarily due to:

- Lower trade receivables related to collections from higher revenues recognized in December 2022, and lower receivables and collateral provided in the Energy Marketing segment due to lower market prices,
- Lower cash and cash equivalents, mainly from the use of cash to complete the acquisition of the RNW Shares and
- Lower risk management assets mainly due to lower market prices and higher contract settlements.

Current liabilities decreased by $1,146 million from $2,888 million as at Dec. 31, 2022, to $1,742 million as at Dec. 31, 2023, mainly due to:

- Lower risk management liabilities due to lower market prices, as well as higher contract settlements during the year,
- Lower accounts payable and accrued liabilities including returning collateral received in the Energy Marketing segment due to lower market prices and
- Lower income taxes payable, partially offset by
- Higher debt classified as current as the $400 million Term Facility matures in the third quarter of 2024.

Non-Current Assets

Non-current assets as at Dec. 31, 2023, were $7,079 million, an increase of $52 million from $7,027 million as at Dec. 31, 2022, primarily due to:

- Higher property, plant and equipment ("PP&E") resulting from higher capital additions of $875 million, mainly related to the construction of growth projects and the rehabilitation of the Kent Hills wind facilities of $157 million, inclusive of insurance proceeds. The increase in PP&E additions was partially offset by depreciation of $585 million and
- Higher net investment in finance leases related to the Northern Goldfields solar facilities, partially offset by
- Lower risk management assets due to changes in market pricing across multiple markets and contract settlements.

Non-Current Liabilities

Non-current liabilities as at Dec. 31, 2023, were $5,253 million, a decrease of $611 million from $5,864 million as at Dec. 31, 2022, mainly due to:

- Lower long-term debt and lease liabilities related to scheduled debt repayments and the reclassification of the $400 million Term Facility to current liabilities,
- Lower risk management liabilities of $59 million related to contract settlements and pricing and
- Lower defined benefit obligations due to higher interest rates and a voluntary pension payment made to reduce our pension obligations, partially offset by
- Higher deferred tax liabilities.

Total Equity

As at Dec. 31, 2023, the decrease in total equity of $325 million was due to:

- A net decrease of $809 million from the acquisition of TransAlta Renewables,
- Distributions to non-controlling interests of $198 million,
- Share repurchases under the NCIB of $87 million and
- Dividends declared on common and preferred shares of $116 million, partially offset by
- Net earnings of $796 million and
- Net gains on derivatives from cash flow hedges of $99 million.

Financial Capital

The Company is focused on maintaining a strong balance sheet and financial position to ensure access to sufficient financial capital. Credit ratings provide information relating to the Company's financing costs, liquidity and operations, and affect the Company's ability to obtain short-term and long-term financing and/or the cost of such financing. Maintaining a strong balance sheet also allows the Company to enter into contracts with a variety of counterparties on terms and prices that are favourable to the Company's financial results and provide TransAlta with better access to capital markets through commodity and credit cycles.

In 2023, Moody's reaffirmed the Company's long-term rating of Ba1 with a stable outlook. Morningstar DBRS reaffirmed the Company's issuer rating and unsecured debt/medium-term notes rating of BBB (low) and the Company's preferred shares rating of Pfd-3 (low), all with stable outlook. In addition, S&P Global Ratings reaffirmed the Company's senior unsecured debt rating and issuer credit rating of BB+ with a stable outlook. Risks associated with our credit ratings are discussed in the Governance and Risk Management section of this MD&A.

Capital Structure

Our capital structure consists of the following components as shown below:

	2023		2022		2021	
	$	%	$	%	$	%
Net senior unsecured debt						
Recourse debt - CAD debentures	**251**	**5**	251	5	251	4
Recourse debt - US senior notes	**911**	**17**	934	18	888	16
Credit facilities	**397**	**7**	428	9	—	—
Other	**—**	**—**	1	—	4	—
Less: cash and cash equivalents(1)	**(345)**	**(6)**	(1,118)	(21)	(947)	(17)
Less: other cash and liquid assets(2)	**(12)**	**—**	(20)	—	(19)	—
Net senior unsecured debt	**1,202**	**23**	476	11	177	3
Other debt liabilities						
Exchangeable debentures	**344**	**6**	339	6	335	6
Non-recourse debt						
TAPC Holdings LP bond	**85**	**1**	94	2	102	2
Pingston bond	**39**	**1**	45	1	45	1
Melancthon Wolfe Wind bond	**168**	**3**	202	4	235	4
New Richmond Wind bond	**103**	**2**	112	2	120	2
Kent Hills Wind bond	**193**	**3**	206	4	221	4
Windrise Wind bond	**164**	**3**	170	3	171	3
South Hedland non-recourse debt	**691**	**13**	711	14	732	13
OCP Bond	**217**	**4**	241	4	263	5
US tax equity financing	**104**	**1**	123	2	135	2
Lease liabilities	**143**	**3**	135	2	100	2
Total consolidated net debt(3)(4)(5)	**3,453**	**63**	2,854	55	2,636	47
Exchangeable preferred securities(5)	**400**	**7**	400	7	400	7
Equity attributable to shareholders						
Common shares	**3,285**	**60**	2,863	54	2,901	51
Preferred shares	**942**	**17**	942	18	942	17
Contributed surplus, deficit and accumulated other comprehensive loss	**(2,690)**	**(49)**	(2,695)	(51)	(2,261)	(40)
Non-controlling interests	**127**	**2**	879	17	1,011	18
Total capital	**5,517**	**100**	5,243	100	5,629	100

(1) Cash and cash equivalents is net of bank overdraft.

(2) Includes principal portion of the TransAlta OCP restricted cash related to the TransAlta OCP bonds as this cash is restricted specifically to repay outstanding debt and also includes the fair value of economic and designated hedging instruments on debt, as the carrying value of the related debt is impacted by changes in foreign exchange rates.

(3) These items are not defined and have no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further discussion, including reconciliations to measures calculated in accordance with IFRS.

(4) The tax equity financing for the Skookumchuck wind facility, an equity-accounted joint venture, is not represented in these amounts.

(5) The total consolidated net debt excludes the exchangeable preferred securities as they are considered equity with dividend payments for credit purposes.

We have enhanced liquidity and shareholder value through the following:

2023

- Extended the committed syndicated credit facility by one year to June 30, 2027 and the committed bilateral credit facilities by one year to June 30, 2025;
- Refinanced the $45 million Pingston non-recourse bond due in 2023 with a non-recourse bond for approximately $39 million, with a fixed interest rate of 6.145 per cent per annum, payable semi-annually, and maturing on May 8, 2043; and
- Purchased and cancelled 7,537,500 common shares at an average price of $11.49 per share through our NCIB program, for a total cost of $87 million.

2022

- Issued US$400 million Senior Green Bonds, with a fixed coupon rate of 7.75 per cent per annum (effective interest rate of 5.98 per cent), due on Nov. 15, 2029;
- Repaid the US$400 million 4.50 per cent unsecured senior notes due 2022;
- Extended the committed syndicated credit facilities by one year to June 30, 2026 and the committed bilateral credit facilities by one year to June 30, 2024;
- Closed a two-year floating rate Term Facility with our banking syndicate for $400 million with a maturity date of Sept. 7, 2024. The Term Facility has interest rates that vary depending on the option selected (e.g. Canadian prime and bankers' acceptances); and
- Purchased and cancelled 4,342,300 common shares at an average price of $12.48 per share through our NCIB program, for a total cost of $54 million.

2021

- Obtained $173 million in project financing related to our Windrise wind facility.

Credit Facilities

The Company's credit facilities are summarized in the table below:

As at Dec. 31, 2023		Utilized			
Credit facilities	**Facility size**	**Outstanding letters of credit[1]**	**Cash drawings**	**Available capacity**	**Maturity date**
Committed					
TransAlta syndicated credit facility	1,950	417	—	1,533	Q2 2027
TransAlta bilateral credit facilities	240	178	—	62	Q2 2025
TransAlta Term Facility	400	—	400	—	Q3 2024
Total committed	**2,590**	**595**	**400**	**1,595**	
Non-committed					
TransAlta demand facilities	400	187	—	213	N/A
Total non-committed	**400**	**187**	**—**	**213**	

(1) TransAlta has obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties, including those related to potential environmental obligations, commodity risk management and hedging activities, pension plan obligations, construction projects and purchase obligations. Letters of credit drawn against the non-committed facilities reduce available capacity under the committed syndicated credit facilities.

On Oct. 5, 2023, upon closing the TransAlta Renewables transaction, the syndicated credit facilities were amended to effectively consolidate the TransAlta Renewables syndicated credit facility and non-committed demand facility into the TransAlta credit facilities. The cash drawings on the TransAlta Renewables' syndicated credit facility were repaid and the outstanding letters of credit were transferred to the TransAlta non-committed demand facility. The TransAlta Renewables credit facilities were then terminated. This resulted in the TransAlta syndicated credit facility increasing by $700 million to approximately $2.0 billion.

See the Significant and Subsequent events section of this MD&A for more details.

Non-Recourse Debt and Other

The Melancthon Wolfe Wind LP, TAPC Holdings LP, New Richmond Wind LP, Kent Hills Wind LP, TEC Hedland Pty Ltd. and Windrise Wind LP non-recourse bonds, and TransAlta OCP LP bonds, are subject to customary financing conditions and covenants that may restrict the Company's ability to access funds generated by the facilities' operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the fourth quarter of 2023, with the exception of Kent Hills Wind LP and TAPC Holdings LP. Kent Hills Wind LP cannot make any distributions to its partners until the foundation replacement work has been completed and TAPC Holdings LP has been impacted by higher interest rates in 2023. The funds in these entities that have accumulated since the fourth quarter test will remain there until the next debt service coverage ratio is calculated in the first quarter of 2024. At Dec. 31, 2023, $79 million (Dec. 31, 2022 – $50 million) of cash was subject to these financial restrictions.

At Dec. 31, 2023, $3 million (AU$3 million) of funds held by TEC Hedland Pty Ltd. are not able to be accessed by other corporate entities as the funds must be solely used by the project entities for the purpose of paying major maintenance costs.

Additionally, certain non-recourse bonds require that reserve accounts be established and funded through cash held on deposit and/or by providing letters of credit.

Between 2024 and 2026, we have a total of $811 million of debt repayments, including the $400 million maturity of the Term Facility, with the balance of $411 million related to scheduled non-recourse debt repayments. The $750 million of exchangeable securities can be exchanged at the earliest on Jan. 1, 2025.

US Tax Equity Financing and Production Tax Credits

The Company owns equity interests in wind facilities that are eligible for tax incentives available for renewable energy facilities in the US. Current US tax law allows qualified wind energy projects to receive production tax credits ("PTCs") that are earned for each MWh of generation during the first 10 years of the project's operation. In order to monetize tax incentives, the Company has partnered with Tax Equity Investors ("TEI") who invest in these facilities in exchange for a share of the tax incentives and cash. TransAlta accounts for the TEI interest as long-term debt, where cash distributions and allocations of tax incentives to the TEI primarily reduce the long-term debt balance. Upon the TEI achieving an agreed-upon after-tax investment return, the project Flip Point occurs. Prior to achieving the Flip Point, the TEI are allocated substantially all of the taxable attributes including PTCs produced and a proportion of cash. After the Flip Point has been reached, the Company retains substantially all of the cash and the taxable income (losses) generated by the facility.

In 2023, US tax laws were amended to allow entities to monetize certain clean energy tax credits, including PTCs, by transferring (selling) them to third-party taxpayers, in exchange for cash consideration.

The following table outlines information regarding the Company's tax equity financing arrangements with PTC eligibility:

Facility	Commercial operation date	Expected Flip Point	Initial TEI investment ($)	Expected annual PTC ($)	TEI allocation of cash distributions (pre-Flip Point) Undiscounted(1) ($)	TEI allocation of taxable income and PTCs (pre-Flip Point)
Lakeswind	2014	2029	45	1	11	99%
Big Level and Antrim	2019	2030	126	10	46	99%
Skookumchuck(2)	2020	2030	121	10	21	99%

(1) Cumulative expected cash distributions from Dec. 31, 2023 to the expected Flip Point.

(2) The Company has a 49 per cent interest in the Skookumchuck wind facility, which is treated as an equity investment under IFRS and our proportionate share of the net earnings is reflected as equity income on the statement of earnings under IFRS.

Returns to Providers of Capital

Interest Income and Interest Expense

Interest income and the components of interest expense are shown below:

Year ended Dec. 31	2023	2022	2021
Interest income	**59**	24	11
Interest on debt	**203**	164	163
Interest on exchangeable debentures	**29**	29	29
Interest on exchangeable preferred shares	**28**	28	28
Capitalized interest	**(57)**	(16)	(14)
Interest on lease liabilities	**9**	7	7
Credit facility fees, bank charges and other interest	**21**	27	20
Tax shield on tax equity financing	**—**	(2)	(9)
Accretion of provisions	**48**	49	32
Interest expense	**281**	286	256

Interest income was higher due to higher cash balances and favourable interest rates. Interest expense was lower than 2022, primarily due to higher capitalized interest resulting from higher capital expenditures on growth projects. This was partially offset by higher interest on debt due to higher credit facility borrowings and higher year-over-year interest rates on variable rate debt.

Share Capital

The following tables outline the common and preferred shares issued and outstanding:

	Number of shares (millions)		
As at	**Feb. 22, 2024**	**Dec. 31, 2023**	**Dec. 31, 2022**
Common shares issued and outstanding, end of period	**307.1**	**308.6**	268.1
Preferred shares			
Series A	**9.6**	**9.6**	9.6
Series B	**2.4**	**2.4**	2.4
Series C	**10.0**	**10.0**	10.0
Series D	**1.0**	**1.0**	1.0
Series E	**9.0**	**9.0**	9.0
Series G	**6.6**	**6.6**	6.6
Preferred shares issued and outstanding in equity	**38.6**	**38.6**	38.6
Series I - Exchangeable Securities(1)	**0.4**	**0.4**	0.4
Preferred shares issued and outstanding	**39.0**	**39.0**	39.0

(1) Brookfield invested $400 million in consideration for redeemable, retractable, first preferred shares. For accounting purposes, these preferred shares are considered debt and disclosed as such in the consolidated financial statements.

Non-Controlling Interests

On Oct. 5, 2023, the Company acquired all of the outstanding common shares of TransAlta Renewables not already owned, directly or indirectly, by TransAlta and certain of its affiliates. See the Significant and Subsequent Events section of this MD&A for details.

As at Dec. 31, 2023, the Company owned 50.01 per cent of TransAlta Cogeneration, LP ("TA Cogen") (Dec. 31, 2022 – 50.01 per cent), which owns, operates or has an interest in three natural-gas-fired cogeneration facilities (Ottawa, Windsor and Fort Saskatchewan) and a natural-gas-fired facility (Sheerness). As at Dec. 31, 2023, the Company owned 83 per cent of Kent Hills Wind LP (Dec. 31, 2022 - 83 per cent), which owns and operates three wind facilities. Throughout 2022, on Dec. 31, 2022, and from Jan. 1, 2023 to Oct. 4, 2023, the Company owned 60.1 per cent of TransAlta Renewables.

Since the Company owned a controlling interest in TA Cogen and Kent Hills Wind LP, we consolidated the entire earnings, assets and liabilities in relation to the subsidiaries. Earnings, assets and liabilities of these subsidiaries, and of TransAlta Renewables prior to Oct. 5, 2023, were allocated to the other owners in proportion to their ownership interests.

The reported net earnings attributable to non-controlling interests for the year ended Dec. 31, 2023, decreased by $10 million, compared to 2022, primarily as a result of lower TA Cogen net earnings attributable to non-controlling interests resulting from lower production and lower merchant pricing in the Alberta market. TransAlta Renewables net earnings attributable to non-controlling interests increased by $1 million for the year ended Dec. 31, 2023 compared to 2022.

Cash Flows

The following highlights significant changes in the Consolidated Statements of Cash Flows for the year ended Dec. 31, 2023 and Dec. 31, 2022:

Year ended Dec. 31	2023	2022	Increase/ (decrease)
Cash and cash equivalents, beginning of year	**1,134**	947	187
Provided by (used in):			
Operating activities	**1,464**	877	587
Investing activities	**(814)**	(741)	(73)
Financing activities	**(1,432)**	45	(1,477)
Translation of foreign currency cash	**(4)**	6	(10)
Cash and cash equivalents, end of year	**348**	1,134	(786)

Cash Flow from Operating Activities

Cash from operating activities for the year ended Dec. 31, 2023, increased compared with the same period in 2022, primarily due to the following:

	Year ended Dec. 31
Cash flow from operating activities for the year ended Dec. 31, 2022	877
Higher gross margin: Lower natural gas costs included in fuel and purchased power, partially offset by lower revenues net of unrealized gains and losses from risk management activities and higher carbon compliance costs.	127
Higher OM&A: Increased spending on strategic and growth initiatives; higher costs associated with the relocation of the Company's head office; and increased costs due to inflationary pressures.	(18)
Lower current income tax expense: Previously restricted non-capital loss carryforwards were utilized to offset taxable income.	15
Higher interest income: Higher cash balances and favourable interest rates	35
Favourable change in non-cash operating working capital balances: Lower accounts receivable and collateral provided as a result of volatility in the market and market prices, partially offset by lower accounts payable and collateral received related to derivative instruments.	440
Other	(12)
Cash flow from operating activities for the year ended Dec. 31, 2023	**1,464**

Cash Flow used in Investing Activities

Cash used in investing activities for the year ended Dec. 31, 2023, increased compared with the same period in 2022, primarily due to the following:

	Year ended Dec. 31
Cash flow used in investing activities for the year ended Dec. 31, 2022	(741)
Lower additions to PP&E: Additions in 2022 were mainly for the construction of the White Rock wind projects, Garden Plain wind facility, the Horizon Hill wind project and the Northern Goldfields solar facilities. In 2023, most of these facilities achieved commercial operation.	43
Lower intangible assets: Lower additions of intangibles under development.	18
Lower proceeds on sale of PP&E: In 2022, the Company closed the sale of two hydro facilities and sold equipment related to its Sundance Unit 5 energy transition assets and other equipment.	(37)
Unfavourable change in non-cash investing working capital balances: Lower capital accruals.	(28)
Other(1)	(69)
Cash flow used in investing activities for the year ended Dec. 31, 2023	**(814)**

(1) Other is mainly comprised of higher spend on project development costs in 2023, higher contributions to investments in 2023, lower insurance proceeds in 2023 and lower settlements in 2023.

Cash Flow from (used in) Financing Activities

Cash used in financing activities for the year ended Dec. 31, 2023, increased compared with the same period in 2022, primarily due to the following:

	Year ended Dec. 31
Cash flow from financing activities for the year ended Dec. 31, 2022	45
Lower repayment of long-term debt: In 2022, the Company repaid the US$400 million senior notes.	457
Higher share capital issuance: Used cash and issued shares to acquire TransAlta Renewables.	(811)
Lower net increase in borrowings under credit facilities: In 2022, the Company fully utilized the $400 million Term Facility, which continues to remain outstanding.	(495)
Lower issuance of long-term debt: In 2022, the Company issued US$400 million senior notes.	(493)
Lower realized gains on financial instruments: The Company recognized a gain on the repayment of US$400 million senior notes in 2022.	(72)
Higher distributions paid to non-controlling interests: Timing of distributions to TA Cogen, partially offset by lower distributions to TransAlta.	(36)
Higher repurchases of common shares under the NCIB.	(35)
Other	8
Cash flow used in financing activities for the year ended Dec. 31, 2023	**(1,432)**

Other Consolidated Analysis

Unconsolidated Structured Entities or Arrangements

Disclosure is required of all unconsolidated structured entities or arrangements such as transactions, agreements or contractual arrangements with unconsolidated entities, structured finance entities, special purpose entities or variable interest entities that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources. We currently have no such unconsolidated structured entities or arrangements.

Related-Party Transactions

In the normal course of operations, we enter into transactions on market terms with related parties, including consolidated and equity accounted entities, which have been measured at exchange value and are recognized in the consolidated financial statements, including, but not limited to asset management fees, power purchase and derivative contracts. Refer to Note 35, Related-Party Transactions in the consolidated financial statements for further details.

Guarantee Contracts

We have obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties, including those related to potential environmental obligations, commodity risk management and hedging activities, pension plan obligations, construction projects and purchase obligations. At Dec. 31, 2023, we provided letters of credit totalling $782 million (2022 – $1.2 billion) and cash collateral of $145 million (2022 – $304 million).

These letters of credit and cash collateral secure certain amounts included on our Consolidated Statements of Financial Position under risk management liabilities, defined benefit obligations and other long-term liabilities and decommissioning and other provisions. The decrease in the amount of letters of credit issued during 2023 relates to lower letters of credit on physical and financial derivative transactions in a net liability position.

Commitments

Contractual commitments are as follows:

	2024	2025	2026	2027	2028	2029 and thereafter	Total
Natural gas and transportation contracts(1)	55	49	50	48	57	436	695
Transmission(1)	9	9	6	4	5	93	126
Coal supply and mining agreements(1)	86	71	—	—	—	—	157
Long-term service agreements(1)	60	57	42	44	37	184	424
Operating leases(1,2)	3	3	2	2	2	25	37
Long-term debt(3)	526	142	143	153	162	2,237	3,363
Exchangeable securities(4)	—	—	—	—	—	750	750
Principal payments on lease liabilities(5)	4	4	4	4	4	123	143
Interest on long-term debt and lease liabilities(1,6)	186	167	158	151	143	711	1,516
Interest on exchangeable securities(1,4)	53	53	53	53	53	13	278
Growth(1,7)	47	—	—	—	—	—	47
Total	**1,029**	**555**	**458**	**459**	**463**	**4,572**	**7,536**

(1) Not recognized as a financial liability on the Consolidated Statements of Financial Position.

(2) Includes leases that have not been recognized as a lease liability and leases that have not yet commenced.

(3) Excludes impact of hedge accounting and derivatives.

(4) Cash payment could occur after Dec. 31, 2028 if exchangeable securities are not exchanged by Brookfield Renewable Partners or its affiliates (collectively "Brookfield"). At Brookfield's option, the exchangeable securities can be exchanged, at the earliest, on Jan. 1, 2025.

(5) Lease liabilities exclude a lease incentive of $12 million expected to be received in 2024, which is recognized in trade and other receivables.

(6) Interest on long-term debt is based on debt currently in place with no assumption as to refinancing on maturity.

(7) For further details on growth commitments, refer to the Strategy and Capability to Deliver Results section of this MD&A.

Contingencies

TransAlta is occasionally named as a party in various claims and legal and regulatory proceedings that arise during the normal course of its business. TransAlta reviews each of these claims, including the nature of the claim, the amount in dispute or claimed and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in the Company's favour or that such claims may not have a material adverse effect on TransAlta. Inquiries from regulatory bodies may also arise in the normal course of business, to which the Company responds as required.

The Company conducts internal reviews of its offers and offer behaviour in both the energy and ancillary services markets in Alberta on an ongoing basis and will self-report suspected contraventions or respond to inquiries from regulatory agencies as required. There currently is no certainty that any particular matter will be resolved in the Company's favour or that such matters may not have a material adverse effect on TransAlta.

Brazeau Facility - Well Licence Applications to Consider Hydraulic Fracturing Activities

The Alberta Energy Regulator ("AER") issued a subsurface order on May 27, 2019, which does not permit any hydraulic fracturing within three kilometres of the Brazeau facility but permits hydraulic fracturing in all formations (except the Duvernay) within three to five kilometres of the Brazeau facility. Subsequently, two oil and gas operators submitted applications to the AER for 10 well licences (which include hydraulic fracturing activities) within three to five kilometres of the Brazeau facility.

The Company's position, based on independent expert analysis commissioned by the Government of Alberta, is that hydraulic fracturing activities within five kilometres of the Brazeau facility pose an unacceptable risk and that the applications should be denied. The regulatory hearing to consider these applications - Proceeding 379 - was adjourned to April 2025. The other parties to the hearing, including the Company, have supported the adjournment.

Brazeau Facility - Claim Against the Government of Alberta

On Sept. 9, 2022, the Company filed a Statement of Claim against the Alberta Government in the Alberta Court of King's Bench seeking a declaration that: (a) granting mineral leases within five kilometres of the Brazeau facility is a breach of the 1960 agreement between the Company and the Alberta Government; and (b) the Alberta Government is required to indemnify the Company for any costs or damages that result from the risks of hydraulic fracturing near the Brazeau facility. On Sept. 29, 2022, the Alberta Government filed its Statement of Defence, which asserts, among other things, that the Company: (a) is trying to usurp the jurisdiction of the AER; and (b) is out of time under the *Limitations Act* (Alberta). The trial was scheduled for two weeks starting Feb. 26, 2024. The parties to the matter, along with Cenovus Energy Inc., sought an adjournment when AER Proceeding 379 was adjourned. The trial is scheduled to resume in February 2025 in the event the parties are unable to resolve the dispute prior to such date.

Garden Plain

Garden Plain I LP, a wholly owned subsidiary of the Company, retained a third-party contractor to construct the Garden Plain wind project near Hanna, Alberta. The contractor experienced scheduling delays, challenges with construction and significant cost overruns, resulting in overdue deadlines, and has asserted a claim for $49 million in damages. The Company disputes this claim in its entirety and asserts a counterclaim. The parties have initiated the dispute resolution procedure, and the arbitration hearing is set down for three weeks starting April 14, 2025.

Hydro Power Purchase Arrangement ("Hydro PPA") Emissions Performance Credits

The Balancing Pool claimed entitlement to 1,750,000 Emission Performance Credits ("EPCs") earned by the Alberta Hydro facilities as a result of TransAlta opting those facilities into the Carbon Competitiveness Incentive Regulation and Technology Innovation and Emissions Reduction Regulation from 2018-2020 inclusive. The EPCs under dispute had no recorded book value as they were internally generated. The Balancing Pool claimed ownership of the EPCs because it believed the change-in-law provisions under the Hydro PPA required the EPCs to be passed through to the Balancing Pool. TransAlta disputed this claim. The parties have reached a confidential settlement and this matter is now resolved.

Sundance A Decommissioning

TransAlta filed an application with the Alberta Utilities Commission seeking payment from the Balancing Pool for TransAlta's decommissioning costs for Sundance A, including its proportionate share of the Highvale mine. The Balancing Pool and Utilities Consumer Advocate are participating as interveners because they take issue with the decommissioning costs claimed by TransAlta. The application is being heard in the first quarter of 2024 with a decision expected to be rendered in the third quarter of 2024.

Financial Instruments

Financial instruments are used for proprietary trading purposes and to manage our exposure to interest rates, commodity prices and currency fluctuations, as well as other market risks. We may currently use physical and financial swaps, forward sale and purchase contracts, futures contracts, foreign exchange contracts, interest rate swaps and options to achieve our risk management objectives. Some of our physical commodity contracts have been entered into and are held for the purposes of meeting our expected purchase, sale or usage requirements and, as such, are not considered financial instruments, and are not recognized as a financial asset or financial liability. Other physical commodity contracts that are not held for normal purchase or sale requirements, and derivative financial instruments are recognized on the Consolidated Statements of Financial Position and are accounted for using the fair value method of accounting. The initial recognition of fair value and subsequent changes in fair value can affect reported earnings in the period the change occurs if hedge accounting is not elected. Otherwise, changes in fair value will generally not affect earnings until the financial instrument is settled.

Some of our financial instruments and physical commodity contracts qualify for, and are recorded under, hedge accounting rules. The accounting for those contracts, for which we have elected to apply hedge accounting, depends on the type of hedge. Our financial instruments are mainly used for cash flow hedges or non-hedges. These categories and their associated accounting treatments are explained in further detail below.

For all types of hedges, we test for effectiveness at the end of each reporting period to determine if the instruments are performing as intended and hedge accounting can still be applied. The financial instruments we enter into are designed to ensure that future cash inflows and outflows are predictable. In a hedging relationship, the effective portion of the change in the fair value of the hedging derivative does not impact net earnings (loss), while any ineffective portion is recognized in net earnings (loss).

We have certain contracts in our portfolio that, at their inception, do not qualify for, or we have chosen not to elect to apply, hedge accounting. For these contracts, we recognize in net earnings (loss) mark-to-market gains and losses resulting from changes in forward prices compared to the price at which these contracts were transacted. These changes in price alter the timing of earnings recognition, but do not necessarily determine the final settlement amount received. The fair value of future contracts will continue to fluctuate as market prices change. The fair value of derivatives that are not traded on an active exchange, or extend beyond the time period for which exchange-based quotes are available, are determined using valuation techniques or models.

Cash Flow Hedges

Cash flow hedges are categorized as project, foreign exchange, interest rate or commodity hedges and are used to offset foreign exchange, interest rate and commodity price exposures resulting from market fluctuations.

Foreign currency forward contracts and cross-currency swaps may be used to hedge foreign exchange exposures resulting from anticipated contracts and firm commitments denominated in foreign currencies, primarily related to capital expenditures and currency exposures related to US-denominated debt.

Physical and financial swaps, forward sale and purchase contracts, futures contracts and options may be used primarily to offset the variability in future cash flows caused by fluctuations in electricity and natural gas prices. Interest rate swaps may be used to convert the fixed interest cash flows related to interest expense at debt to floating rates and vice versa.

In a cash flow hedge, changes in the fair value of the hedging instrument (a forward contract or financial swap, for example) are recognized in risk management assets or liabilities and the related gains or losses are recognized in other comprehensive income or loss ("OCI"). These gains or losses are subsequently reclassified from OCI to net earnings (loss) in the same period as the hedged forecast cash flows impact net earnings (loss) and offset the losses or gains arising from the forecast transactions. For project hedges, the gains and losses reclassified from OCI are included in the carrying amount of the related PP&E.

Hedge accounting follows a principles-based approach for qualifying hedges that is aligned with an entity's approach to risk management. When we do not elect hedge accounting or when the hedge is no longer effective and does not qualify for hedge accounting, the gains or losses as a result of changes in prices, interest or exchange rates related to these financial instruments are recorded in net earnings (loss) in the period in which they arise.

Net Investment Hedges

Foreign-denominated long-term debt is used to hedge exposure to changes in the carrying values of our net investments in foreign operations that have a functional currency other than the Canadian dollar. Our net investment hedges using US-denominated debt remain effective and in place. Gains or losses on these instruments are recognized and deferred in OCI and reclassified to net earnings on the disposal of the foreign operation. We also manage foreign exchange risk by matching foreign-denominated expenses with revenues, such as offsetting revenues from our US operations with interest payments on our US-dollar debt.

Non-Hedges

Financial instruments not designated as hedges are used for proprietary trading and to reduce commodity price, foreign exchange and interest rate risks. Changes in the fair value of financial instruments not designated as hedges are recognized in risk management assets or liabilities and the related gains or losses are recognized in net earnings (loss) in the period in which the change occurs.

Fair Values

The majority of fair values for our foreign exchange, interest rate, commodity hedges and non-hedge derivatives are calculated using adjusted quoted prices from an active market or inputs validated by broker quotes. We may enter into commodity transactions involving non-standard features for which market-observable data is not available. These transactions are defined under IFRS as Level III instruments. Level III instruments incorporate inputs that are not observable from the market and fair value is therefore determined using valuation techniques. Fair values are validated by using reasonably possible alternative assumptions as inputs to valuation techniques and any material differences are disclosed in the notes to the consolidated financial statements.

At Dec. 31, 2023, Level III instruments had a net liabilities carrying value of $147 million (2022 – net liabilities $782 million). The Level III liabilities decreased in 2023 primarily due to market price changes and contracts settled in the year. Additionally, the long-term fixed price power sale contract in the US for delivery of power was transferred to Level II from Level III as all inputs were observable at Dec. 31, 2023. Our risk management profile has decreased in 2023 as most energy markets have moderated considerably from the extreme price and high volatility environment experienced for much of 2022. Our risk management profile and practices have not changed materially from Dec. 31, 2022.

Refer to the Material Accounting Policies and Critical Accounting Estimates section of this MD&A for further details regarding valuation techniques.

Additional IFRS Measures and Non-IFRS Measures

An additional IFRS measure is a line item, heading or subtotal that is relevant to an understanding of the consolidated financial statements but is not a minimum line item mandated under IFRS, or the presentation of a financial measure that is relevant to an understanding of the consolidated financial statements but is not presented elsewhere in the consolidated financial statements. We have included line items entitled gross margin and operating income (loss) in our Consolidated Statements of Earnings (Loss) for the years ended Dec. 31, 2023, 2022 and 2021. Presenting these line items provides management and investors with a measurement of ongoing operating performance that is readily comparable from period to period.

We use a number of financial measures to evaluate our performance and the performance of our business segments, including measures and ratios that are presented on a non-IFRS basis, as described below. Unless otherwise indicated, all amounts are in Canadian dollars and have been derived from our consolidated financial statements prepared in accordance with IFRS. We believe that these non-IFRS amounts, measures and ratios, read together with our IFRS amounts, provide readers with a better understanding of how management assesses results.

Non-IFRS amounts, measures and ratios do not have standardized meanings under IFRS. They are unlikely to be comparable to similar measures presented by other companies and should not be viewed in isolation from, as an alternative to, or more meaningful than, our IFRS results.

Non-IFRS Financial Measures

Adjusted EBITDA, FFO, FCF, total net debt, total consolidated net debt and adjusted net debt are non-IFRS measures that are presented in this MD&A. Refer to the Segmented Financial Performance and Operating Results, Selected Quarterly Information, Financial Capital and Key Non-IFRS Financial Ratios sections of this MD&A for additional information, including a reconciliation of such non-IFRS measures to the most comparable IFRS measure.

Adjusted EBITDA

Each business segment assumes responsibility for its operating results measured by adjusted EBITDA. Adjusted EBITDA is an important metric for management that represents our core operational results. Interest, taxes, depreciation and amortization are not included, as differences in accounting treatments may distort our core business results. In addition, certain reclassifications and adjustments are made to better assess results, excluding those items that may not be reflective of ongoing business performance. This presentation may facilitate the readers' analysis of trends.

The following are descriptions of the adjustments made.

Adjustments to Revenue

- Certain assets that we own in Canada and in Australia are fully contracted and recorded as finance leases under IFRS. We believe that it is more appropriate to reflect the payments we receive under the contracts as a capacity payment in our revenues instead of as finance lease income and a decrease in finance lease receivables.
- Adjusted EBITDA is adjusted to exclude the impact of unrealized mark-to-market gains or losses and unrealized foreign exchange gains or losses on commodity transactions.
- Adjustments are made for gains and losses related to closed positions effectively settled by offsetting positions with exchanges that have been recorded in the period the positions are settled.

Adjustments to Fuel and Purchased Power

- On the commissioning of the South Hedland facility in July 2017, we prepaid approximately $74 million of electricity transmission and distribution costs. Interest income is recorded on the prepaid funds. We reclassify this interest income as a reduction in the transmission and distribution costs expensed each period to reflect the net cost to the business.

Adjustments to Net Other Operating Income

- Insurance recoveries related to the Kent Hills tower collapse are not included as these relate to investing activities and are not reflective of ongoing business performance.

Adjustments to Earnings (Loss) in Addition to Interest, Taxes, Depreciation and Amortization

- Asset impairment charges and reversals are not included as these are accounting adjustments that impact depreciation and amortization and do not reflect ongoing business performance.
- Any gains or losses on asset sales or foreign exchange gains or losses are not included as these are not part of operating income.

Adjustments for Equity-Accounted Investments

- During the fourth quarter of 2020, we acquired a 49 per cent interest in the Skookumchuck wind facility, which is treated as an equity investment under IFRS and our proportionate share of the net earnings is reflected as equity income on the statement of earnings under IFRS. As this investment is part of our regular power-generating operations, we have included our proportionate share of the adjusted EBITDA of the Skookumchuck wind facility in our total adjusted EBITDA.

In addition, in the Wind and Solar adjusted results, we have included our proportionate share of revenues and expenses to reflect the full operational results of this investment. We have not included EMG International, LLC's adjusted EBITDA in our total adjusted EBITDA as it does not represent our regular power-generating operations.

Average Annual EBITDA

Average annual EBITDA is a forward-looking non-IFRS financial measure that is used to show the average annual EBITDA that the project currently under construction is expected to generate upon completion.

Funds From Operations ("FFO")

FFO is an important metric as it provides a proxy for cash generated from operating activities before changes in working capital and provides the ability to evaluate cash flow trends in comparison with results from prior periods. FFO is a non-IFRS measure.

Adjustments to Cash Flow from Operations

- FFO related to the Skookumchuck wind facility, which is treated as an equity-accounted investment under IFRS and equity income, net of distributions from joint ventures, is included in cash flow from operations under IFRS. As this investment is part of our regular power generating operations, we have included our proportionate share of FFO.
- Payments received on finance lease receivables are reclassified to reflect cash from operations.
- We adjust for items within the Energy Transition segment that may not be reflective of ongoing operations including certain costs related to decisions made to accelerate our transition off-coal in Alberta and our planned transition off-coal for Centralia. These are included in the "Clean energy transition provisions and adjustments" in the reconciliation.
- Cash received/paid on closed positions are reflected in the period that the position is settled.
- Other adjustments include payments/receipts for production tax credits, which are reductions to tax equity debt and include distributions from equity-accounted joint ventures.

Free Cash Flow ("FCF")

FCF is an important metric as it represents the amount of cash that is available to invest in growth initiatives, make scheduled principal repayments on debt, repay maturing debt, pay common share dividends or repurchase common shares. Changes in working capital are excluded so FFO and FCF are not distorted by changes that we consider temporary in nature, reflecting, among other things, the impact of seasonal factors and timing of receipts and payments. FCF is a non-IFRS measure.

Non-IFRS Ratios

FFO per share, FCF per share and adjusted net debt to adjusted EBITDA are non-IFRS ratios that are presented in the MD&A. Refer to the Reconciliation of Cash Flow from Operations to FFO and FCF and Key Non-IFRS Financial Ratios sections of this MD&A for additional information.

FFO per Share and FCF per Share

FFO per share and FCF per share are calculated using the weighted average number of common shares outstanding during the period. FFO per share and FCF per share are non-IFRS ratios.

Supplementary Financial Measures

The Alberta electricity portfolio metrics disclosed are supplementary financial measures used to present the gross margin by segment for the Alberta market. Refer to the Alberta Electricity Portfolio section of this MD&A for additional information.

Full Year Reconciliation of Non-IFRS Measures on a Consolidated Basis by Segment

The following table reflects adjusted EBITDA by segment and provides reconciliation to earnings before income taxes for the year ended Dec. 31, 2023:

	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	533	357	1,514	751	220	1	3,376	(21)	—	3,355
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(4)	16	(67)	(5)	23	—	(37)	—	37	—
Realized gain (loss) on closed exchange positions	—	—	10	—	(91)	—	(81)	—	81	—
Decrease in finance lease receivable	—	—	55	—	—	—	55	—	(55)	—
Finance lease income	—	—	12	—	—	—	12	—	(12)	—
Unrealized foreign exchange loss on commodity	—	—	1	—	—	—	1	—	(1)	—
Adjusted revenues	529	373	1,525	746	152	1	3,326	(21)	50	3,355
Fuel and purchased power	19	30	453	557	—	1	1,060	—	—	1,060
Reclassifications and adjustments:										
Australian interest income	—	—	(4)	—	—	—	(4)	—	4	—
Adjusted fuel and purchased power	19	30	449	557	—	1	1,056	—	4	1,060
Carbon compliance	—	—	112	—	—	—	112	—	—	112
Gross margin	510	343	964	189	152	—	2,158	(21)	46	2,183
OM&A	48	80	192	64	43	115	542	(3)	—	539
Taxes, other than income taxes	3	12	11	3	—	1	30	(1)	—	29
Net other operating income	—	(7)	(40)	—	—	—	(47)	—	—	(47)
Reclassifications and adjustments:										
Insurance recovery	—	1	—	—	—	—	1	—	(1)	—
Adjusted net other operating income	—	(6)	(40)	—	—	—	(46)	—	(1)	(47)
Adjusted EBITDA[2]	459	257	801	122	109	(116)	1,632			
Equity income										4
Finance lease income										12
Depreciation and amortization										(621)
Asset impairment reversals										48
Interest income										59
Interest expense										(281)
Foreign exchange loss										(7)
Gain on sale of assets and other										4
Earnings before income taxes										880

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

The following table reflects adjusted EBITDA by segment and provides reconciliation to earnings before income taxes for the year ended Dec. 31, 2022:

	Hydro	Wind & Solar[(1)]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[(1)]	Reclass adjustments	IFRS financials
Revenues	606	303	1,209	714	160	(2)	2,990	(14)	—	2,976
Reclassifications and adjustments:										
Unrealized mark-to-market loss	1	104	251	10	12	—	378	—	(378)	—
Realized gain (loss) on closed exchange positions	—	—	(4)	—	47	—	43	—	(43)	—
Decrease in finance lease receivable	—	—	46	—	—	—	46	—	(46)	—
Finance lease income	—	—	19	—	—	—	19	—	(19)	—
Unrealized foreign exchange gain on commodity	—	—	—	—	(1)	—	(1)	—	1	—
Adjusted revenues	607	407	1,521	724	218	(2)	3,475	(14)	(485)	2,976
Fuel and purchased power	22	31	641	566	—	3	1,263	—	—	1,263
Reclassifications and adjustments:										
Australian interest income	—	—	(4)	—	—	—	(4)	—	4	—
Adjusted fuel and purchased power	22	31	637	566	—	3	1,259	—	4	1,263
Carbon compliance	—	1	83	(1)	—	(5)	78	—	—	78
Gross margin	585	375	801	159	218	—	2,138	(14)	(489)	1,635
OM&A	55	68	195	69	35	101	523	(2)	—	521
Taxes, other than income taxes	3	12	15	4	—	1	35	(2)	—	33
Net other operating income	—	(23)	(38)	—	—	—	(61)	3	—	(58)
Reclassifications and adjustments:										
Insurance recovery	—	7	—	—	—	—	7	—	(7)	—
Adjusted net other operating income	—	(16)	(38)	—	—	—	(54)	3	(7)	(58)
Adjusted EBITDA[(2)]	527	311	629	86	183	(102)	1,634			
Equity income										9
Finance lease income										19
Depreciation and amortization										(599)
Asset impairment charges										(9)
Interest income										24
Interest expense										(286)
Foreign exchange gain										4
Gain on sale of assets and other										52
Earnings before income taxes										353

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.

(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

The following table reflects adjusted EBITDA by segment and provides reconciliation to earnings before income taxes for the year ended Dec. 31, 2021:

	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	383	323	1,109	709	211	4	2,739	(18)	—	2,721
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	25	(40)	19	(38)	—	(34)	—	34	—
Realized gain (loss) on closed exchange positions	—	—	(6)	—	29	—	23	—	(23)	—
Decrease in finance lease receivable	—	—	41	—	—	—	41	—	(41)	—
Finance lease income	—	—	25	—	—	—	25	—	(25)	—
Unrealized foreign exchange gain on commodity	—	—	(3)	—	—	—	(3)	—	3	—
Adjusted revenues	383	348	1,126	728	202	4	2,791	(18)	(52)	2,721
Fuel and purchased power	16	17	457	560	—	4	1,054	—	—	1,054
Reclassifications and adjustments:										
Australian interest income	—	—	(4)	—	—	—	(4)	—	4	—
Mine depreciation	—	—	(79)	(111)	—	—	(190)	—	190	—
Coal inventory writedown	—	—	—	(17)	—	—	(17)	—	17	—
Adjusted fuel and purchased power	16	17	374	432	—	4	843	—	211	1,054
Carbon compliance	—	—	118	60	—	—	178	—	—	178
Gross margin	367	331	634	236	202	—	1,770	(18)	(263)	1,489
OM&A	42	59	175	117	36	84	513	(2)	—	511
Reclassifications and adjustments:										
Parts and materials writedown	—	—	(2)	(26)	—	—	(28)	—	28	—
Curtailment gain	—	—	—	6	—	—	6	—	(6)	—
Adjusted OM&A	42	59	173	97	36	84	491	(2)	22	511
Taxes, other than income taxes	3	10	13	6	—	1	33	(1)	—	32
Net other operating income	—	—	(40)	48	—	—	8	—	—	8
Reclassifications and adjustments:										
Royalty onerous contract and contract termination penalties	—	—	—	(48)	—	—	(48)	—	48	—
Adjusted net other operating income	—	—	(40)	—	—	—	(40)	—	48	8
Adjusted EBITDA[2]	322	262	488	133	166	(85)	1,286			
Equity income										9
Finance lease income										25
Depreciation and amortization										(529)
Asset impairment charges										(648)
Interest income										11
Interest expense										(256)
Foreign exchange gain										16
Gain on sale of assets and other										54
Loss before income taxes										(380)

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.

(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Full Year Reconciliation of Cash Flow from Operations to FFO and FCF

The table below reconciles our cash flow from operating activities to our FFO and FCF:

	2023	2022	2021
Cash flow from operating activities[1]	**1,464**	877	1,001
Change in non-cash operating working capital balances	**(124)**	316	(174)
Cash flow from operations before changes in working capital	**1,340**	1,193	827
Adjustments			
Share of adjusted FFO from joint venture[1]	**8**	8	13
Decrease in finance lease receivable	**55**	46	41
Clean energy transition provisions and adjustments[2]	**11**	42	79
Realized gain (loss) on closed exchanged positions	**(81)**	37	23
Other[3]	**18**	20	11
FFO[4]	**1,351**	1,346	994
Deduct:			
Sustaining capital[1]	**(174)**	(142)	(199)
Productivity capital	**(3)**	(4)	(4)
Dividends paid on preferred shares	**(51)**	(43)	(39)
Distributions paid to subsidiaries' non-controlling interests	**(223)**	(187)	(159)
Principal payments on lease liabilities	**(10)**	(9)	(8)
FCF[4]	**890**	961	585
Weighted average number of common shares outstanding in the period	**276**	271	271
FFO per share[4]	**4.89**	4.97	3.67
FCF per share[4]	**3.22**	3.55	2.16

(1) Includes our share of amounts for the Skookumchuck wind facility, an equity-accounted joint venture.

(2) 2023 includes amounts related to onerous contracts recognized in 2021 and a voluntary contribution to the US Defined Benefit Pension Plan for the Centralia thermal facility. During 2022, to support the employees affected by the closure of the Highvale mine and our transition off coal to cleaner sources, the Company made a voluntary special contribution of $35 million to the Highvale mine pension plan. 2022 also includes amounts related to onerous contracts recognized in 2021. 2021 includes a write-down on parts and material inventory and coal inventory for our coal operations and amounts related to onerous contracts and contract termination penalties.

(3) Other consists of production tax credits, which is a reduction to tax equity debt, less distributions from equity-accounted joint venture.

(4) These items are not defined and have no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

The table below provides a reconciliation of our adjusted EBITDA to our FFO and FCF:

Year ended Dec. 31	2023	2022	2021
Adjusted EBITDA(1)(4)	**1,632**	1,634	1,286
Provisions	**(1)**	25	(43)
Net interest expense(2)	**(164)**	(200)	(200)
Current income tax expense	**(50)**	(65)	(56)
Realized foreign exchange loss	**(4)**	—	(2)
Decommissioning and restoration costs settled	**(37)**	(35)	(18)
Other non-cash items	**(25)**	(13)	27
FFO(3)(4)	**1,351**	1,346	994
Deduct:			
Sustaining capital(4)	**(174)**	(142)	(199)
Productivity capital	**(3)**	(4)	(4)
Dividends paid on preferred shares	**(51)**	(43)	(39)
Distributions paid to subsidiaries' non-controlling interests	**(223)**	(187)	(159)
Principal payments on lease liabilities	**(10)**	(9)	(8)
FCF(4)	**890**	961	585

(1) Adjusted EBITDA is defined in the Additional IFRS Measures and Non-IFRS Measures section of this MD&A and reconciled to earnings (loss) before income taxes above.

(2) Net interest expense includes interest expense for the period less interest income.

(3) These items are not defined and have no standardized meaning under IFRS. FFO and FCF are defined in the Additional IFRS Measures and Non-IFRS Measures section of this MD&A and reconciled to cash flow from operating activities above.

(4) Includes our share of amounts for the Skookumchuck wind facility, an equity-accounted joint venture.

Fourth Quarter Reconciliation of Non-IFRS Measures on a Consolidated Basis by Segment

The following table reflects adjusted EBITDA by segment and provides reconciliation to earnings before income taxes for the three months ended Dec. 31, 2023:

	Hydro	Wind & Solar[(1)]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[(1)]	Reclass adjustments	IFRS financials
Revenues	77	94	246	175	39	—	631	(7)	—	624
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(2)	20	53	7	(19)	—	59	—	(59)	—
Realized gain on closed exchange positions	—	—	23	—	4	—	27	—	(27)	—
Decrease in finance lease receivable	—	—	15	—	—	—	15	—	(15)	—
Finance lease income	—	—	2	—	—	—	2	—	(2)	—
Unrealized foreign exchange gain on commodity	—	—	1	—	—	—	1	—	(1)	—
Adjusted revenues	75	114	340	182	24	—	735	(7)	(104)	624
Fuel and purchased power	5	8	127	138	—	—	278	—	—	278
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted fuel and purchased power	5	8	126	138	—	—	277	—	1	278
Carbon compliance	—	—	27	—	—	—	27	—	—	27
Gross margin	70	106	187	44	24	—	431	(7)	(105)	319
OM&A	13	25	56	18	10	29	151	(1)	—	150
Taxes, other than income taxes	1	1	—	—	—	1	3	—	—	3
Net other operating income	—	(3)	(10)	—	—	—	(13)	—	—	(13)
Reclassifications and adjustments:										
Insurance recovery	—	1	—	—	—	—	1	—	(1)	—
Adjusted net other operating income	—	(2)	(10)	—	—	—	(12)	—	(1)	(13)
Adjusted EBITDA[(2)]	56	82	141	26	14	(30)	289			
Equity income										3
Finance lease income										2
Depreciation and amortization										(132)
Asset impairment reversals										(26)
Interest income										12
Interest expense										(66)
Foreign exchange loss										(7)
Loss before income taxes										(35)

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.

(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

The following table reflects adjusted EBITDA by segment and provides reconciliation to loss before income taxes for the three months ended Dec. 31, 2022:

	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	159	98	276	281	44	—	858	(4)	—	854
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	1	23	238	(7)	12	—	267	—	(267)	—
Realized gain on closed exchange positions	—	—	7	—	20	—	27	—	(27)	—
Decrease in finance lease receivable	—	—	12	—	—	—	12	—	(12)	—
Finance lease income	—	—	4	—	—	—	4	—	(4)	—
Unrealized foreign exchange gain on commodity	—	—	—	—	(1)	—	(1)	—	1	—
Adjusted revenues	160	121	537	274	75	—	1,167	(4)	(309)	854
Fuel and purchased power	5	11	196	234	—	—	446	—	—	446
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted fuel and purchased power	5	11	195	234	—	—	445	—	1	446
Carbon compliance	—	—	27	—	—	—	27	—	—	27
Gross margin	155	110	315	40	75	—	695	(4)	(310)	381
OM&A	22	18	57	19	12	30	158	(1)	—	157
Taxes, other than income taxes	—	5	2	2	—	—	9	(1)	—	8
Net other operating income	—	(5)	(8)	—	—	—	(13)	3	—	(10)
Adjusted EBITDA[2]	133	92	264	19	63	(30)	541			
Equity income										4
Finance lease income										4
Depreciation and amortization										(188)
Asset impairment charges										(5)
Interest income										10
Interest expense										(77)
Foreign exchange loss										(13)
Gain on sale of assets and other										46
Earnings before income taxes										7

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.

(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Fourth Quarter Reconciliation of Cash Flow from Operations to FFO and FCF

The table below reconciles our cash flow from operating activities to our FFO and FCF:

Three months ended Dec. 31	2023	2022
Cash flow from operating activities[1]	**310**	351
Change in non-cash operating working capital balances	**(135)**	64
Cash flow from operations before changes in working capital	**175**	415
Adjustments		
Share of adjusted FFO from joint venture[1]	**(2)**	1
Decrease in finance lease receivable	**15**	12
Clean energy transition provisions and adjustments[2]	**4**	7
Realized gain on closed exchanged positions	**27**	21
Other[3]	**10**	3
FFO[3]	**229**	459
Deduct:		
Sustaining capital[1]	**(74)**	(67)
Productivity capital	**(1)**	(1)
Dividends paid on preferred shares	**(12)**	(12)
Distributions paid to subsidiaries' non-controlling interests	**(19)**	(61)
Principal payments on lease liabilities	**(2)**	(3)
FCF[4]	**121**	315
Weighted average number of common shares outstanding in the period	**308**	269
FFO per share[4]	**0.74**	1.71
FCF per share[4]	**0.39**	1.17

(1) Includes our share of amounts for Skookumchuck, an equity-accounted joint venture.

(2) Includes amounts related to onerous contracts recognized in 2021 and a voluntary contribution to the US Defined Benefit Pension Plan for the Centralia thermal facility.

(3) Other consists of production tax credits, which is a reduction to tax equity debt, less distributions from the equity-accounted joint venture.

(4) These items are not defined and have no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

The table below provides a reconciliation of our adjusted EBITDA to our FFO and FCF for the three months ended Dec 31. 2023 and 2022:

Three months ended Dec. 31	2023	2022
Adjusted EBITDA[(1)(4)]	**289**	541
Provisions	**(1)**	20
Net interest expense[(2)]	**(41)**	(49)
Current income tax recovery (expense)	**5**	(29)
Realized foreign exchange gain (loss)	**9**	(18)
Decommissioning and restoration costs settled	**(15)**	(12)
Other non-cash items	**(17)**	6
FFO[(3)(4)]	**229**	459
Deduct:		
Sustaining capital[(4)]	**(74)**	(67)
Productivity capital	**(1)**	(1)
Dividends paid on preferred shares	**(12)**	(12)
Distributions paid to subsidiaries' non-controlling interests	**(19)**	(61)
Principal payments on lease liabilities	**(2)**	(3)
FCF[(4)]	**121**	315

(1) Adjusted EBITDA is defined in the Additional IFRS Measures and Non-IFRS Measures section of this MD&A and reconciled to earnings (loss) before income taxes above.

(2) Net interest expense includes interest expense for the period less interest income.

(3) These items are not defined and have no standardized meaning under IFRS. FFO and FCF are defined in the Additional IFRS Measures and Non-IFRS Measures section of this MD&A and reconciled to cash flow from operating activities above.

(4) Includes our share of amounts for the Skookumchuck wind facility, an equity-accounted joint venture.

Key Non-IFRS Financial Ratios

The methodologies and ratios used by rating agencies to assess our credit rating are not publicly disclosed. We have developed our own definitions of ratios and targets to help evaluate the strength of our financial position. These metrics and ratios are not defined and have no standardized meaning under IFRS and may not be comparable to those used by other entities or by rating agencies.

Adjusted Net Debt to Adjusted EBITDA

Year ended Dec. 31	2023	2022	2021
Period-end long-term debt(1)	**3,466**	3,653	3,267
Exchangeable debentures	**344**	339	335
Less: Cash and cash equivalents(2)	**(345)**	(1,118)	(947)
Add: 50 per cent of issued preferred shares and exchangeable preferred shares(3)	**671**	671	671
Other(4)	**(12)**	(20)	(19)
Adjusted net debt(5)	**4,124**	3,525	3,307
Adjusted EBITDA(6)	**1,632**	1,634	1,286
Adjusted net debt to adjusted EBITDA (times)	**2.5**	2.2	2.6

(1) Consists of current and long-term portion of debt, which includes lease liabilities and tax equity financing.

(2) Cash and cash equivalents, net of bank overdraft.

(3) Exchangeable preferred shares are considered equity with dividend payments for credit-rating purposes. For accounting purposes, they are accounted for as debt with interest expense in the consolidated financial statements. For purposes of this ratio, we consider 50 per cent of issued preferred shares, including these, as debt.

(4) Includes principal portion of TransAlta OCP restricted cash ($17 million for 2023, 2022 and 2021) and fair value of hedging instruments on debt (included in risk management assets and/or liabilities on the Consolidated Statements of Financial Position).

(5) The tax equity financing for the Skookumchuck wind facility, an equity-accounted joint venture, is not represented in this amount. Adjusted net debt is not defined and has no standardized meaning under IFRS. Presenting this item from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(6) Last 12 months.

The Company's capital is managed using a net debt position. We use the adjusted net debt to adjusted EBITDA ratio as a measurement of financial leverage and to assess our ability to service debt. Our target for adjusted net debt to adjusted EBITDA is 3.0 to 4.0 times. Our adjusted net debt to adjusted EBITDA ratio for Dec. 31, 2023 was higher compared to Dec. 31, 2022, due to higher adjusted net debt resulting from lower cash and cash equivalents due to the acquisition of TransAlta Renewables, partially offset by scheduled debt repayments and a lower amount outstanding on the credit facility at the end of 2023.

2024 Outlook

For 2024, the Company expects adjusted EBITDA to be in the range of $1.15 billion to $1.3 billion and FCF to be in the range of $450 million to $600 million which is based on the following:

- Higher contribution from the wind and solar portfolio due to the full year impact of new asset additions of the Garden Plain wind facility and Northern Goldfields solar facilities, as well as the full return to service of Kent Hills wind facilities in the first quarter of 2024;
- Contributions from the addition of Mount Keith transmission;
- Contributions from the commercial operation of the White Rock and Horizon Hill wind projects which are expected in the first quarter of 2024;
- Contribution from the Heartland Generation acquisition, which is expected to close in 2024;
- Lower contributions from the legacy merchant hydro, wind and gas portfolio in Alberta which are expected to step down due to lower expected average power prices in Alberta given the baseload gas and renewables supply additions expected in 2024;

- Higher expected current income tax expense in 2024 in the absence of growth that could defer or partially offset the Company's tax horizon; and
- Increased net interest expense in 2024 as a result of lower interest income earned on lower cash deposits and lower capitalized interest on growth projects.

The following table outlines our expectations on key financial targets and related assumptions for 2024 and should be read in conjunction with the narrative discussion that follows and the Governance and Risk Management section of this MD&A:

	2024 Target	Updated Target 2023	2023 Actuals
Adjusted EBITDA(1)(2)	$1,150 million - $1,300 million	$1,700 million - $1,800 million	$1,632 million
FCF(1)(2)	$450 million - $600 million	$850 million - $950 million	$890 million
FCF per share	$1.47 - $1.96	$2.77 - $3.10	$3.22
Dividend	$0.24 per share annualized	$0.22 per share annualized	$0.22 per share annualized

(1) These items are not defined and have no standardized meaning under IFRS. Refer to the Reconciliation of Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS. See also the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(2) During the second quarter of 2023, the Company revised and increased our 2023 guidance for adjusted EBITDA and FCF based on the strong financial performance attained in the first half of the year and our expectations for the balance of the year.

The Company's outlook for 2024 may be impacted by a number of factors as detailed further below.

Range of key 2024 power and gas price assumptions

Market	2024 Assumptions	Updated Target 2023	2023 Actuals
Alberta spot ($/MWh)	$75 to $95	$150 to $170	$134
Mid-C spot (US$/MWh)	US$85 to US$95	US$90 to US$110	US$76
AECO gas price ($/GJ)	$2.50 to $3.00	$2.50	$2.54

Alberta spot price sensitivity: a +/- $1 per MWh change in spot price is expected to have a +/-$5 million impact on adjusted EBITDA for 2024.

Other assumptions relevant to the 2024 outlook

	2024 Expectations
Energy Marketing gross margin	$110 million to $130 million
Sustaining capital	$130 million to $150 million
Corporate cash taxes	$95 million to $130 million
Cash interest	$240 million to $260 million

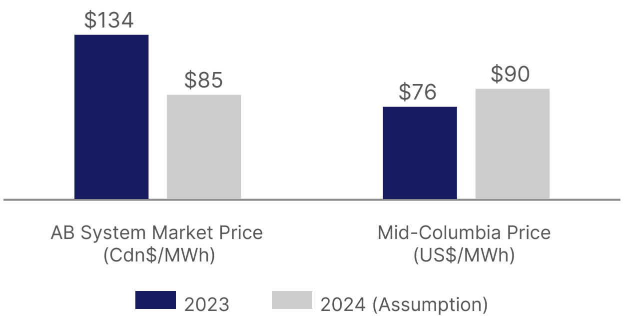
Alberta Hedging

Range of hedging assumptions	2024
Hedged production (GWh)	8,152
Hedge price ($/MWh)	$85
Hedged gas volumes (GJ)	62 million
Hedge gas prices ($/GJ)	$2.76

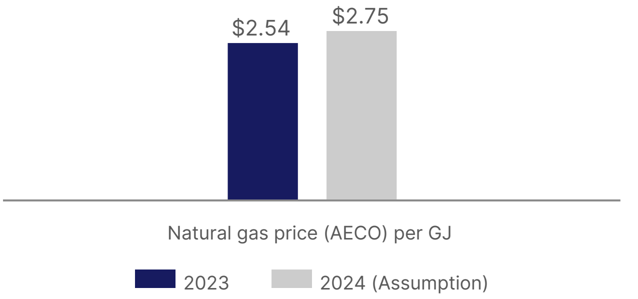
Market Pricing

The following graphs include 2024 pricing based on a range of assumptions and is subject to change:

Annual Average Spot Electricity Prices



Annual Average Gas (AECO) Prices



For 2024, spot electricity prices in Alberta are expected to be lower compared to 2023, driven by normalized weather expectations and the anticipated additions of new natural gas, and wind and solar supply. Spot electricity prices in the Pacific Northwest are expected to be higher in 2024, but will depend on the actual hydrology for the region during the year.

AECO natural gas prices are expected to be comparable to 2023.

The objective of our portfolio management strategy in Alberta is to balance opportunity and risk and to deliver optimization strategies that contribute to our total investment, which includes a return on invested capital. We can be more or less hedged in a given period, and we expect to realize our annual targets through a combination of forward hedging and selling generation into the spot market. The assets within the Alberta electricity portfolio are managed as a portfolio to maximize the overall value of generation and capacity from our hydro, wind, energy storage and thermal facilities. Hedging is a key component of cash flow certainty and the hedges are primarily tied to our portfolio of gas assets and opportunistically allocated to our portfolio of hydro facilities rather than a single facility.

Sustaining Capital Expenditures

Our estimate for total sustaining capital is as follows:

	Spent in 2023	Expected spend in 2024
Total sustaining capital (millions)	174	130-150

The Company expects sustaining capital to be in the range of $130 million to $150 million. The midpoint for the range represents a 10 per cent decrease from the midpoint of the 2023 outlook sustaining capital range of $140 million to $170 million, and a 20 per cent decrease from 2023 sustaining capital spend. This is driven by lower sustaining capital expenditures for planned major maintenance related to the gas assets and lower costs associated with the relocation of the Company's head office.

Liquidity and Capital Resources

We expect to maintain adequate available liquidity under our committed credit facilities. As at Dec. 31, 2023, we had access to $1.7 billion in liquidity, including $345 million in cash, net of bank overdraft; which significantly exceeds the funds required for committed growth, sustaining capital and productivity projects. .

Material Accounting Policies and Critical Accounting Estimates

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as accounting rules and guidance have changed. Accounting rules generally do not involve a selection among alternatives, but involve the implementation and interpretation of existing rules and the use of judgment relative to the circumstances existing in the business. Every effort is made to comply with all applicable rules on or before the effective date and we believe the proper implementation and consistent application of accounting rules is critical.

However, not all situations are specifically addressed in the accounting literature. In these cases, our best judgment is used to adopt a policy for accounting for these situations. We draw analogies to similar situations and the accounting guidelines governing them, consider foreign accounting standards and consult with our independent auditors about the appropriate interpretation and application of these policies. Each of the critical accounting policies involves complex situations and a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our consolidated financial statements.

Our material accounting policies are described in Note 2 of the consolidated financial statements. Each policy involves a number of estimates and assumptions to be made about matters that are uncertain at the time the estimate is made. Different estimates, with respect to key variables used for the calculations, or changes to estimates, could potentially have a material impact on our financial position or results of operations.

We have discussed the development and selection of these critical accounting estimates with the Audit, Finance and Risk Committee ("AFRC") of the Board of Directors and our independent auditors. The AFRC has reviewed and approved our disclosure relating to critical accounting estimates in this MD&A. These critical accounting estimates are described as follows:

Revenue Recognition

Revenue from Contracts with Customers

Identification of Performance Obligations

Where contracts contain multiple promises for goods or services, management exercises judgment in determining whether goods or services constitute distinct goods or services or a series of distinct goods or services that are substantially the same and that have the same pattern of transfer to the customer. The determination of a performance obligation affects whether the transaction price is recognized at a point in time or over time. Management considers both the mechanics of the contract and the economic and operating environment of the contract in determining whether the goods or services in a contract are distinct.

Transaction Price

In determining the transaction price and estimates of variable consideration, management considers the past history of customer usage and capacity requirements when estimating the goods and services to be provided to the customer. The Company also considers the historical production levels and operating conditions for its variable generating assets.

Allocation of Transaction Price to Performance Obligations

When multiple performance obligations are present in a contract, transaction price is allocated to each performance obligation in an amount that depicts the consideration the Company expects to be entitled to in exchange for transferring the good or service.

The Company's contracts generally outline a specific amount to be invoiced to a customer associated with each performance obligation in the contract. Where contracts do not specify amounts for individual performance obligations, the Company estimates the amount of the transaction price to allocate to individual performance obligations based on their standalone selling price, which is primarily estimated based on the amounts that would be charged to customers under similar market conditions.

Satisfaction of Performance Obligations

The satisfaction of performance obligations requires management to use judgment as to when control of the underlying good or service transfers to the customer. Determining when a performance obligation is satisfied affects the timing of revenue recognition. Management considers both customer acceptance of the good or service and the impact of laws and regulations such as certification requirements in determining when this transfer occurs. Management also applies judgment in determining whether the invoice practical expedient permits recognition of revenue at the invoiced amount if that invoiced amount corresponds directly with the entity's performance to date.

Revenue from Other Sources

Revenue from Derivatives

Commodity risk management activities involve the use of derivatives such as physical and financial swaps, forward sales contracts, futures contracts and options that are used to earn revenues and to gain market information. These derivatives are accounted for using fair value accounting. The determination of the fair value of commodity risk management contracts and derivative instruments is complex and relies on judgments concerning future prices, volatility and liquidity, among other factors.

Some of our derivatives are not traded on an active exchange or extend beyond the time period for which exchange-based quotes are available, requiring us to use internal valuation techniques or other models such as numerical derivative valuation or scenario analysis.

Merchant Revenue

Revenues from non-contracted capacity (i.e., merchant) are comprised of energy payments, at market price, for each MWh produced and are recognized upon delivery.

Financial Instruments

The fair value of a financial instrument is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair values can be determined by reference to prices for instruments in active markets to which we have access. In the absence of an active market, we determine fair values based on valuation models or by reference to other similar products in active markets.

Fair values determined using valuation models require the use of assumptions. In determining those assumptions, we look primarily to external readily observable market inputs. However, if not available, we use inputs that are not based on observable market data.

Level Determinations and Classifications

The Level I, II and III classifications in the fair value hierarchy are utilized by the Company. The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based on the lowest level input that is significant to the derivation of the fair value. Refer to Note 14(I) and (II) from our consolidated financial statements for further details on the inputs used for each level.

The effect of using reasonably possible alternative assumptions as inputs to valuation techniques for contracts included in the Level III fair value measurements at Dec. 31, 2023, is an estimated total upside of $92 million (2022 – $193 million) and total downside of $116 million (2022 – $287 million) impact to the carrying value of the financial instruments. Fair values are stressed for unobservable inputs, which can include variable volumes, unobservable prices and wind discounts, among other inputs. The variable volumes are stressed up and down based on historically available production data. Prices are stressed for longer-term deals where there are no liquid market quotes using various internal and external forecasting sources to establish a high and a low price range. Wind discounts represent price to volume relationships and are stressed specific to each location.

In addition to the Level III fair value measurements discussed above, the Brookfield Investment Agreement allows Brookfield the option to exchange all of the outstanding exchangeable securities into an equity ownership interest of up to a maximum of 49 per cent in an entity formed to hold TransAlta's Alberta Hydro Assets after Dec. 31, 2024. The fair value of the option to exchange is considered a Level III fair value measurement, with an estimated downside of $25 million (2022 – $25 million) potential impact to the carrying value of nil as at Dec. 31, 2023 (2022 – nil). The sensitivity analysis has been prepared using the Company's assessment that a change in the implied discount rate of the future cash flow of one per cent is a reasonably possible change.

Valuation of PP&E and Associated Contracts

At the end of each reporting period, we assess whether there is any indication that PP&E and finite life intangible assets are impaired or whether a previously recognized impairment may no longer exist or may have decreased.

Our operations, the market and business environment are routinely monitored and judgments and assessments are made to determine whether an event has occurred that indicates a possible impairment. If such an event has occurred, an estimate is made of the recoverable amount of the asset or cash-generating unit ("CGU") to which the asset belongs. A CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets and goodwill is allocated to each CGU or group of CGUs that is expected to benefit from the synergies of the acquisition from which the goodwill arose. The recoverable amount is the higher of an asset's fair value less costs of disposal or its value in use. Fair value is the price that would be received to sell an asset in an orderly transaction between market participants at the measurement date. In determining fair value less costs of disposal, information about third-party transactions for similar assets is used and if none is available, other valuation techniques, such as discounted cash flows, are used. Value in use is computed using the present value of management's best estimates of future cash flows based on the current use and present condition of the asset. In estimating either fair value less costs of disposal or value in use using discounted cash flow methods, estimates and assumptions must be made about sales prices, cost of sales, production, fuel consumed, capital expenditures, retirement costs and other related cash inflows and outflows over the life of the facilities, which can range from 30 to 49 years. In developing these assumptions, management uses estimates of contracted and future market prices based on expected market supply and demand in the region in which the facility operates, anticipated production levels, planned and unplanned outages, changes to regulations and transmission capacity or constraints for the remaining life of the facilities.

Discount rates are determined by employing a weighted average cost of capital methodology that is based on capital structure, cost of equity and cost of debt assumptions based on comparable companies with similar risk characteristics and market data as the asset, CGU or group of CGUs subject to the test. These estimates and assumptions are susceptible to change from period to period and actual results can and often do differ from the estimates and can have either a positive or negative impact on the estimate of the impairment charge and may be material.

The impairment outcome can also be impacted by the determination of CGUs or groups of CGUs for asset and goodwill impairment testing. The allocation of goodwill is reassessed upon changes in the composition of segments, CGUs or groups of CGUs. In respect of determining CGUs, significant judgment is required to determine what constitutes independent cash flows between power facilities that are connected to the same system. We evaluate the market design, transmission constraints and the contractual profile of each facility, as well as our commodity price risk management plans and practices, in order to inform this determination. With regard to the allocation or reallocation of goodwill, significant judgment is required to evaluate synergies and their impacts. Minimum thresholds also exist with respect to segmentation and internal monitoring activities.

We evaluate synergies with regard to opportunities from combined talent and technology, functional organization and future growth potential and we consider our own performance measurement processes in making this determination. No changes arose in our CGUs in 2023.

PP&E impairment charges can be reversed in future periods if circumstances improve. No assurances can be given if any reversal will occur or the amount or timing of any such reversal.

Asset Impairments

Hydro

During 2023, internal valuations indicated the fair value less costs of disposal for two hydro facilities exceeded the carrying value due to a contract extension and changes in power price assumptions, which favourably impacted estimated future cash flows and resulted in a full recoverability test. As a result of the recoverability test an impairment reversal of $10 million was recognized.

Wind and Solar

During 2023, the Company recorded a net impairment reversal of $4 million as a result of changes in power price assumptions for two wind facilities, which favourably impacted estimated future cash flows and resulted in a full recoverability test.

Valuation of Goodwill

We evaluate goodwill for impairment at least annually, or more frequently if indicators of impairment exist. If the carrying amount of a CGU or group of CGUs, including goodwill, exceeds the unit's fair value, the excess represents a goodwill impairment loss.

For the purposes of the 2023 goodwill impairment review, the Company determined the recoverable amounts of the Wind and Solar segment by calculating the fair value less costs of disposal using discounted cash flow projections. In 2023, the Company relied on the recoverable amounts determined in 2022 for the Hydro and Energy Marketing segments in performing the 2023 goodwill impairment review. The recoverable amounts are based on the Company's long-range forecasts for the periods extending to the last planned asset retirement in 2072. The resulting fair value measurement is categorized within Level III of the fair value hierarchy. We have determined there were no goodwill impairments for 2023, 2022 and 2021.

Determining the fair value of the CGUs or group of CGUs is susceptible to changes from period to period as management is required to make assumptions about future cash flows, including estimates of contracted and future market prices based on expected market supply and demand in the region in which the facility operates, anticipated production levels, planned and unplanned outages, changes to regulations and transmission capacity or constraints for the remaining life of the facilities.

Project Development Costs

Project development costs include external, direct and incremental costs that are necessary for completing an acquisition or construction project. The appropriateness of capitalization of these costs is evaluated each reporting period and amounts capitalized for projects no longer probable of occurring are charged to net earnings (loss).

Useful Life of PP&E

Each significant component of an item of PP&E is depreciated over its estimated useful life. A component is a tangible asset that can be separately identified as an asset and is expected to provide a benefit of greater than one year. Estimated useful lives are determined based on current facts and past experience and take into consideration the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecasted demand, the potential for technological obsolescence and regulations. The useful lives of PP&E and depreciation rates used are reviewed at least annually to ensure they continue to be appropriate.

Change in Estimate - Useful Lives

During 2023, the Company adjusted the useful lives of certain assets in the Gas segment to reflect changes made based on future operating expectations of the assets. This resulted in a decrease of $92 million in depreciation expense that was recognized in the Consolidated Statement of Earnings (Loss) in 2023.

Leases

In determining whether the Company's contracts contain, or are, leases, management must use judgment to assess whether the contract provides the customer with the right to substantially all of the economic benefits from the use of the asset during the lease term and whether the customer obtains the right to direct the use of the asset during the lease term. For those agreements considered to contain, or be, leases, further judgment is required to determine the lease term by assessing whether termination or extension options are reasonably certain to be exercised. Judgment is also applied in identifying in-substance fixed payments (included) and variable payments that are based on usage or performance factors (excluded) and in identifying lease and non-lease components (services that the supplier performs) of contracts and in allocating contract payments to lease and non-lease components.

For leases where the Company is a lessor, judgment is required to determine if substantially all of the significant risks and rewards of ownership are transferred to the customer or remains with the Company, to appropriately account for the agreement as either a finance or operating lease. These judgments can be significant and impact how we classify amounts related to the arrangement as either PP&E or as a finance lease receivable on the Consolidated Statements of Financial Position and therefore the amount of certain items of revenue and expense are dependent upon such classifications.

Income Taxes

Preparation of the consolidated financial statements involves determining an estimate of, or provision for, income taxes in each of the jurisdictions in which we operate. The process also involves making an estimate of taxes currently payable and income taxes expected to be payable or recoverable in future periods, referred to as deferred income taxes. An assessment must also be made to determine the likelihood that our future taxable income will be sufficient to permit the recovery of deferred income tax assets. To the extent that such recovery is not probable, deferred income tax assets must be reduced. The reduction of the deferred income tax asset can be reversed if the estimated future taxable income improves. No assurances can be given if any reversal will occur or the amount or timing of any such reversal. Management must exercise judgment in its assessment of continually changing tax interpretations, regulations and legislation to ensure deferred income tax assets and liabilities are complete and fairly presented. Differing assessments and applications than our estimates could materially impact the amount recognized for deferred income tax assets and liabilities. Our tax filings are subject to audit by taxation authorities. The outcome of some audits may change our tax liability, although we believe that we have adequately provided for income taxes in accordance with IFRS based on all information currently available. The outcome of pending audits is not known nor is the potential impact on the consolidated financial statements determinable.

Employee Future Benefits

We provide selected pension and other post-employment benefits to employees, such as health and dental benefits. The cost of providing these benefits is dependent upon many factors, including actual plan experience and estimates and assumptions about future experience.

The liabilities for pension, other post-employment benefits and associated pension costs included in annual compensation expenses are impacted by employee demographics, including age, compensation levels, employment periods, the level of contributions made to the plans and earnings on plan assets.

Changes to the provisions of the plans may also affect current and future pension costs. Pension costs may also be significantly impacted by changes in key actuarial assumptions, including, for example, the discount rates used in determining the defined benefit obligation and the net interest cost on the net defined benefit liability. The discount rate used to estimate our obligation reflects high-quality corporate fixed income securities currently available and expected to be available during the period to maturity of the pension benefits.

Defined Benefit Obligation

The liability for pension and post-employment benefits and associated costs included in compensation expenses are impacted by estimates related to changes in key actuarial assumptions, including discount rates. The defined benefit obligation has increased by $5 million to $155 million as at Dec. 31, 2023, from $150 million as at Dec. 31, 2022. A one per cent increase in discount rates would have a $40 million impact on the defined benefit obligation.

Decommissioning and Restoration Provisions

We recognize decommissioning and restoration provisions for generating facilities and mine sites in the period in which they are incurred if there is a legal or constructive obligation to remove the facilities and restore the site. The amount recognized as a provision is the best estimate of the expenditures required to settle the provision. Expected values are probability weighted to deal with the risks and uncertainties inherent in the timing and amount of settlement of many decommissioning and restoration provisions. Expected values are discounted at the current market-based risk-free interest rate adjusted to reflect the market's evaluation of our credit standing.

The Company recognizes provisions for decommissioning obligations. Initial decommissioning provisions and subsequent changes thereto, are determined using the Company's best estimate of the required cash expenditures, adjusted to reflect the risks and uncertainties inherent in the timing and amount of settlement.

During 2023, the decommissioning and restoration provision decreased by $89 million due to revisions in estimated cash flows and timing of cash flows for certain Gas and Energy Transition assets. The timing of cash flows was adjusted to optimize and maximize efficiencies by staging required reclamation work. Operating assets included in PP&E decreased by $34 million and $55 million was recognized as an impairment reversal in net earnings related to retired assets.

During 2023, revisions in discount rates increased the decommissioning and restoration provision by $52 million due to a decrease in discount rates, largely driven by decreases in long-term market benchmark rates. On average, discount rates decreased compared to 2022, with rates ranging from 6.0 to 9.0 per cent as at Dec. 31, 2023. This has resulted in a corresponding increase in PP&E of $31 million on operating assets and the recognition of a $21 million impairment charge in net earnings related to retired assets.

Other Provisions

Where necessary, we recognize provisions arising from ongoing business activities, such as interpretation and application of contract terms, ongoing litigation and force majeure claims. These provisions and subsequent changes thereto, are determined using our best estimate of the outcome of the underlying event and can also be impacted by determinations made by third parties, in compliance with contractual requirements. The actual amount of the provisions that may be required could differ materially from the amount recognized.

Classification of Joint Arrangements

Upon entering into a joint arrangement, the Company must classify it as either a joint operation or joint venture and the classification affects the accounting for the joint arrangement. In making this classification, the Company exercises judgment in evaluating the terms and conditions of the arrangement to determine whether the parties have rights to the assets and obligations or rights to the net assets. Factors such as the legal structure, contractual arrangements and other facts and circumstances, such as where the purpose of the arrangement is primarily for the provision of the output to the parties and when the parties are substantially the only source of cash flows for the arrangement, must be evaluated to understand the rights of the parties to the arrangement.

Significant Influence

Upon entering into an investment, the Company must classify it as either an investment as an associate or an investment under IFRS 9. In making this classification, the Company exercises judgment in evaluating whether the Company has significant influence over the investee. Significant influence is the power to participate in the financial and operating policy decisions of the investee, but is not control or joint control over those policies. If the Company holds 20 per cent or more of the voting rights in the investee, it is presumed that the entity has significant influence, unless it can be clearly demonstrated that this is not the case. Other factors such as representation on the board of directors, participation in policy-making processes, material transactions between the Company and investee, interchange of managerial personnel or providing essential technical information are considered when assessing if the Company has significant influence over an investee.

Accounting Changes

Current Accounting Changes

Amendments to IAS 12 Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction

On May 7, 2021, the International Accounting Standards Board ("IASB") issued Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction, which amends IAS 12 Income Taxes. The amendments clarify that the initial recognition exemption under IAS 12 does not apply to transactions such as leases and decommissioning obligations. These transactions give rise to equal and offsetting temporary differences in which deferred tax should be recognized.

The amendments are effective for annual periods beginning on or after Jan. 1, 2023, and were adopted by the Company on that date. The Company's accounting aligns with the amendment and no financial impact arose upon adoption.

Amendments to IAS 12 International Tax Reform — Pillar Two Model Rules

The Organization for Economic Co-operation and Development (OECD) published Pillar Two model rules in December 2021 to ensure that large multinational companies would be subject to a minimum 15 per cent tax rate. In May 2023, the IASB issued amendments to IAS 12 Income Taxes to provide companies with immediate temporary relief from accounting for deferred taxes arising from the OECD international tax reform. The amendments clarify that IAS 12 applies to income taxes arising from tax law enacted or substantively enacted to implement the Pillar Two model rules published by the OECD. Pillar Two legislation has not been enacted or substantively enacted in any jurisdiction in which the Company operates and therefore has not been reflected within our tax provisions at Dec. 31, 2023.

Future Accounting Changes

Amendments to IAS 1 Non-current Liabilities with Covenants and Classification of Liabilities as Current or Non-current

In October 2022, the IASB issued Non-current Liabilities with Covenants, which amends IAS 1 Presentation of Financial Statements, to clarify how conditions with which an entity must comply within 12 months after the reporting period affect the classification of a liability. In January 2020, the IASB issued Classification of Liabilities as Current or Non-current, which amends IAS 1 Presentation of Financial Statements regarding the classification of liabilities as current or non-current, clarifying that contractual rights and conditions existing at the end of the reporting period are relevant in determining whether the Company has a right to defer settlement of a liability by at least 12 months.

Additionally, the IASB clarified that the classification of a liability is unaffected by the likelihood that an entity will exercise its deferral right. The amendments are effective for annual periods beginning on or after Jan. 1, 2024, and are to be applied retrospectively. On Jan. 1, 2024, the Company will re-classify the Exchangeable Securities from non-current liabilities to current liabilities as the conversion option can be exercised at any time after Jan. 1, 2025, although there is no obligation to deliver cash equivalent resources and the holder cannot call for repayment. This accounting is consistent with the amendment.

Environmental, Social and Governance

Sustainability, or ESG management and performance, is a priority at TransAlta. Sustainability is one of our core values, which means it is part of our corporate culture. We perpetually strive to further integrate sustainability into our governance, decision-making, risk management and day-to-day business processes, while enabling our growth strategy. The ultimate outcome of our sustainability focus is continuous improvement on key, material ESG issues and ensuring our economic value creation is balanced with a value proposition for the environment and our stakeholders.

Our key strategic sustainability pillars build on our corporate strategy and weave through our business. Our track record in these areas illustrates our commitment to sustainability (including climate change leadership and safety). In other areas, where we have set new goals in recent years (including equity, diversity and inclusion), we believe the focus will only strengthen our corporate strategy and support value creation into the future. Our pillars include:

- **Clean, Reliable and Sustainable Electricity Production**
- **Safe, Healthy, Diverse and Engaged Workplace**
- **Positive Indigenous, Stakeholder and Customer Relationships**
- **Progressive Environmental Stewardship**
- **Technology and Innovation**

Reporting on Our Material Sustainability Factors

TransAlta has been reporting on sustainability since 1994. The Company's ESG reporting content is integrated within this MD&A to provide information on how ESG affects our business (including material focus areas) and is guided by leading ESG reporting frameworks. We adopt guidance from the International Sustainability Standards Board by the International Financial Reporting Standards ("IFRS") Foundation, the International Integrated Reporting Framework, the Global Reporting Initiative ("GRI") and the Sustainability Accounting Standards Board ("SASB") requirements for electric utilities and power generators. We continue to monitor the development of sustainability and climate-related disclosure requirements to assess our future reporting, such as the proposed climate-related disclosure rules by the Canadian Securities Administrators, the US Securities and Exchange Commission and the Australian government.

Since 2007, TransAlta's material sustainability data to be disclosed has received limited assurance from independent third-party providers. Climate-related data to be disclosed is informed by the IFRS S2 Climate-related Disclosures Standard launched in 2023, in alignment with the recommendations of the Task Force on Climate-related Financial Disclosures ("TCFD"). In 2024, TransAlta will continue to focus on our alignment with the IFRS S2 requirements. As a result, we no longer expect to respond to climate change questionnaires from CDP (the global disclosure system for environmental impacts known formerly as the Carbon Disclosure Project). We will continue to monitor its future guidance for the purpose of continuous improvement of our voluntary climate-related disclosures.

In 2023, we reviewed and updated our management response to our 2021 climate-related scenario analysis that enhanced our alignment with both international sustainability frameworks. We also reviewed and updated our Climate Transition Plan and climate-related financial metrics. GHG emissions data for scopes 1 and 2 follow the accounting and reporting standards of the GHG Protocol. We continue to make advancements in our scope 3 accounting for future reporting in alignment with the GHG Protocol. For further information on climate change management and the findings of our scenario analysis, refer to the Decarbonizing Our Energy Mix section of this MD&A.

The disclosure of our most relevant sustainability factors remained in 2023 and is guided by our sustainability materiality assessment. In 2022, we refreshed our materiality assessment by evaluating key sector-specific research on material issues, supported by internal and external engagement on key sustainability issues. Our Enterprise Risk Management ("ERM") program is designed to help the Company focus its efforts on key enterprise risks, within the planning horizon, that could significantly impact the success of our strategy, including our sustainability objectives. We consider a sustainability factor as material if it could substantively affect our ability to create value.

In addition, we reviewed key topics identified within SASB, TCFD, IFRS and the Taskforce on Nature-related Financial Disclosures to inform the identification of our material sustainability factors. We also considered sustainability factors from the electricity sector through Electricity Canada's 2021 Sustainable Electricity Report and conducted a peer review of material sustainability factors. This work was validated by our executive team and resulted in the identification of 21 material sustainability factors presented in the Sustainability Governance section of this MD&A.

For further guidance on our risk factors, refer to the Governance and Risk Management section of this MD&A.

Accelerating Our Business Transformation with a Target to Become Net-Zero by 2045

At TransAlta, our mission is to provide safe, low-cost and reliable clean electricity to our customers. As a customer-centred clean electricity leader, we are well positioned to support our customers' ESG and sustainability goals. To achieve this goal, in today's evolving economy and increasingly electrified world, our strategy focuses on renewable electricity growth and a deep commitment to sustainability. We believe that we are uniquely positioned as the world continues to electrify and adopt sustainability practices. For further information, refer to the Description of the Business section of this MD&A.

Our President and Chief Executive Officer, John Kousinioris, speaks about our decarbonization journey below.

What role do you see natural gas generation having in a successful energy transition?

“We believe that there are three factors that must be balanced to ensure a successful energy transition: reliability, decarbonization and affordability. We continue to see a role in natural gas-fired generation enabling the energy transition by ensuring the reliability of the electricity grid. Today, our gas fleet, to be strengthened following closing of the Heartland Generation acquisition, includes peaking and baseload generation, which underpin the reliability needs of our grid, as well as cogeneration facilities, which serve customers critical to the industrial sectors of our three core markets. We also work closely with our industrial customers to support their decarbonization goals. For example, we recently achieved commercial operation for the Northern Goldfield solar and battery storage project for BHP Nickel West in Western Australia that is expected to reduce BHP's scope 2 GHG emissions.”

Following closing of the Heartland Generation acquisition, will TransAlta still be able to achieve its 2026 decarbonization target?

“Our commitment to decarbonization remains unchanged. TransAlta’s target of a 75 per cent scope 1 and 2 GHG emissions reduction by 2026 is estimated to align with the Paris Agreement goal to limit global warming to 1.5°C and is based on our 2015 scope 1 and 2 GHG emissions of 32.2 MT CO_2e. The acquisition of the Heartland Generation portfolio is aligned with our decarbonization commitment. We will recalculate our 2015 emission baseline to include emissions from Heartland Generation and expect this transaction will continue to enable us to reduce our emissions in the short term and to be carbon net-zero by 2045.

We remain committed to investing in climate change mitigation solutions to maximize value for our shareholders, customers, local communities and the environment.”

For further information, refer to Climate Change Metrics and Targets in the Decarbonizing Our Energy Mix section of this MD&A.

TransAlta has adopted a 2045 net-zero target. How will the Company achieve this target?

"Our net-zero target is a testament of our growth strategy. We are using the cash flows from our legacy thermal generation assets to fund our transition to a generating fleet focused on renewables and storage by creating electricity solutions for our industrial and commercial customers. In 2023, we revised our Clean Electricity Growth Plan, which targets growing the Company’s generation fleet by an incremental 1.75 GW — with approximately $3.5 billion of capital expenditure — as well as increasing our development pipeline of projects to 10 GW, each to be achieved by 2028. Our investment focus to 2028 will be on renewables and storage assets, responsive and flexible generation to support reliability, and advancing new technological solutions."

Our 2023 Sustainability Performance

In 2023, TransAlta's strong safety performance was a key accomplishment amongst our social performance metrics. Our Total Safety Report Frequency and Total Recordable Injury Frequency ("TRIF") exceeded our performance targets.

Performance against our 2023 sustainability targets is outlined below. Target year means by Dec. 31 of that year.

ESG Alignment: Environmental

Sustainability goal	Sustainability target	Results	Comments
Reduce GHG emissions	By 2026, achieve a 75 per cent reduction of scope 1 and 2 GHG emissions from 2015 base year(1)	*On track*	Since 2015, we have reduced scope 1 and 2 GHG emissions by 21.3 MT CO_2e or 66 per cent
	By 2045, achieve net-zero for 100 per cent of TransAlta's scope 1 and 2 GHG emissions(2)	*On track*	
	By 2024, verify and disclose 80 per cent of TransAlta's scope 3 emissions(3)	*On track*	We completed a pre-assessment of 80 per cent of TransAlta's scope 3 emissions to prepare for limited assurance in 2024
Reduce air emissions	By 2026, achieve a 95 per cent reduction of SO_2 emissions and an 80 per cent reduction of NO_x emissions below 2005 levels	*Achieved*	Our total air emissions in 2023 retained similar performance to 2022 levels. We achieved this target in 2022 through the reduction of our SO_2 emissions by 98 per cent and NO_x emissions by 83 per cent from 2005 levels
Reclaim land utilized for mining	By 2040, complete full reclamation of our Centralia coal mine in Washington State	*On track*	Reclamation work at Centralia is underway and 40 per cent of the coal mine land has been reclaimed
	By 2046, complete full reclamation of our Highvale coal mine in Alberta	*On track*	Our Highvale coal mine in Alberta closed in 2021. Reclamation work is underway and 22 per cent of the coal mine land has been reclaimed
Responsible water management	By 2026, reduce fleet-wide water consumption (withdrawals minus discharge) by 20 million m^3 or 40 per cent over a 2015 baseline	*Achieved in 2022*	Water consumption increased to 30 million m^3 in 2023 primarily due to an increase in production compared to last year. We achieved this target in 2022 through the reduction of our fleet-wide water consumption by approximately 20 million m^3 or 43 per cent from 2015 levels
Protecting nature and biodiversity	By 2024, assess and disclose nature-related risks and opportunities including TransAlta's dependencies and impacts on ecosystems, land, water and air	*On track*	Assessment of nature-related risks and opportunities is underway
	Achieve zero biodiversity-related incidents(4)	*Achieved*	We recorded zero (0) biodiversity-related incidents

(1) TransAlta does not plan to use carbon credits to achieve its 2026 GHG emissions reduction target.

(2) The Company may choose to neutralize residual emissions from gas-fired generation through fuel switching, new technologies or nature-based solutions to achieve its 2045 net-zero target. For further information, refer to Climate Transition Plan in the Decarbonizing Our Energy Mix section of this MD&A.

(3) To calculate TransAlta's scope 3 GHG emissions, we rely on third-party data that is available only after the first quarter of each year. As a result, this target means reporting on 2023 scope 3 GHG emissions data in 2025 following the verification of data by independent third-party providers in 2024.

(4) This means biodiversity-related incidents that affected habitats and species included on the Red List of the International Union for Conservation of Nature and are classified as near-threatened, vulnerable, endangered and critically endangered.

ESG Alignment: Social

Sustainability goal	Sustainability target	Results	Comments
Reduce safety incidents	Achieve a Total Recordable Injury Frequency rate below 0.32	*Achieved*	We achieved a TRIF rate of 0.30 compared to 0.39 in 2022. Our strong safety performance can be attributed to our focus on maturing our safety culture, reducing hazards, assessing and addressing risk tolerance and standardizing safety information and data collection technology
Integrate sustainability into supply chain	By 2024, 80 per cent of our spend will be with suppliers that have a sustainability policy or commitment	*On track*	On average, 78 per cent of our spend in 2022 and 2023 was with suppliers that have a sustainability policy or commitment
Support prosperous Indigenous communities	Support equal access to all levels of education for youth and Indigenous peoples through financial support and employment opportunities	*Achieved*	Support represented a total value of $453,000, or 14 per cent of TransAlta's total community investment
	Provide Indigenous cultural awareness training to all TransAlta employees by the end of 2023	*Achieved*	We provided Indigenous awareness training to all Canadian, Australian and US employees

ESG Alignment: Governance

Sustainability goal	Sustainability target	Results	Comments
Strengthen gender equality	Achieve 50 per cent female representation on the Board by 2030	*On track*	As at Dec. 31, 2023, women represented 46 per cent of our Board composition compared to 36 per cent in 2022(1)
	Achieve at least 40 per cent female employment among all employees of the Company by 2030	*On track*	As at Dec. 31, 2023, women represented 27 per cent of all employees, an increase over 2022 levels (26 per cent)
	Maintain equal pay for women in equivalent roles as men	*Achieved*	We achieved a 97 per cent female/male pay equity ratio. We strive to maintain this ratio within a deviation of plus or minus three per cent
Demonstrate leadership on ESG reporting within financial disclosures	Maintain our position as a leader on integrated ESG disclosure through increased annual alignment with leading sustainability disclosure frameworks	*Achieved*	TransAlta's MSCI ESG Rating was upgraded to 'AA' from 'A'. The upgrade reflects the Company's strong renewable energy growth compared to peers. We also received an award for best ESG reporting (mid-cap) by the IR Magazine Canada. In 2023, TransAlta demonstrated some of the most comprehensive disclosures among utilities companies assessed in the inaugural Climate Engagement Canada Net Zero Benchmark, which evaluates corporate issuers' progress towards aligning with the Paris Agreement's goals

(1) Board composition includes all independent and non-independent directors.

ESG Alignment: Environmental and Social

Sustainability goal	Sustainability target	Results	Comments
Coal transition	No further coal generation by the end of 2025 with 100 per cent of our owned net generation capacity to be from renewables and gas	*On track*	We retired 670 MW of Centralia at Dec. 31, 2020. In 2021, we retired or converted all coal plants in Canada and closed the Highvale coal mine, thus ceasing all coal generation in Canada. Our remaining Centralia plant in the US is set to retire on Dec. 31, 2025
Clean energy solutions for customers	Develop new renewable projects that support customer sustainability goals to achieve both long-term power price affordability and carbon reductions	*On track*	Since 2021, we have added over 800 MW of new capacity through renewable projects such as Windrise (206 MW), Garden Plain (130 MW), Northern Goldfields Solar (48 MW), White Rock (300 MW) and Horizon Hill (200 MW). We also acquired TransAlta Renewables (1.2 GW) in 2023 and North Carolina Solar (122 MW) in 2021. In 2023, our Clean Electricity Growth Plan was updated to continue our priorities. By 2028, the plan will see the Company execute on an incremental 1.75 GW of renewables growth and a 10 GW growth pipeline

2024+ Sustainability Targets

Our 2024 and longer-term sustainability targets support the success of our business so that the Company will continue to be positioned as an ESG leader in the future. Goals and targets are established to improve our ESG performance and manage current and emerging material sustainability issues in support of the United Nations Sustainable Development Goals ("UN SDGs") and the Future-Fit Business Benchmark, which also defines sustainable goals for businesses. TransAlta is committed to decarbonizing our energy generation and accelerating clean energy growth. We believe that we can make a greater positive impact on UN SDG 7 "Affordable and Clean Energy" and SDG 13 "Climate Action", while supporting seven other SDGs.

Our 2024 and long-term sustainability targets reflect on incremental change from the sustainability targets set in 2023. Specifically, TransAlta updated two sustainability targets in the areas of safety and Indigenous cultural awareness, while maintaining our climate-related targets to achieve net-zero for 100 per cent of TransAlta's scope 1 and 2 GHG emissions by 2045 and to reduce 75 per cent of our scope 1 and 2 GHG emissions by 2026 from a 2015 base year. This target covers 100 per cent of TransAlta's operating assets and is estimated to align with the electricity sector decarbonization pathway to limit global warming to 1.5°C, as one of the Paris Agreement goals.

In 2024, we will continue to review setting new environmental targets for GHG emissions, air emissions and water consumption consistent with our commitment to continuously improve our environmental performance.

Targets are outlined below. Target year means by Dec. 31 of that year.

ESG Alignment: Environmental

Sustainability goal	Sustainability target	Alignment with UN SDG Target or Future-Fit Business Benchmark
Reduce GHG emissions	By 2026, achieve a 75 per cent reduction of scope 1 and 2 GHG emissions from 2015 base year[1]	UN SDG Target 13.2: "Integrate climate change measures into national policies, strategies and planning"
	By 2045, achieve net-zero for 100 per cent of TransAlta's scope 1 and 2 GHG emissions[2]	
	By 2024, verify and disclose 80 per cent of TransAlta's scope 3 emissions[3]	
Reduce air emissions	By 2026, achieve a 95 per cent reduction of SO_2 emissions and an 80 per cent reduction of NO_x emissions below 2005 levels	UN SDG Target 9.4: "By 2030, upgrade infrastructure and retrofit industries to make them sustainable, with increased resource-use efficiency and greater adoption of clean and environmentally sound technologies and industrial processes"
Reclaim land utilized for mining	By 2040, complete full reclamation of our Centralia coal mine in Washington State	Future-Fit Business Benchmark: "Positive Pursuits 13: Ecosystems are restored"
	By 2046, complete full reclamation of our Highvale coal mine in Alberta	Future-Fit Business Benchmark: "Positive Pursuits 13: Ecosystems are restored"
Responsible water management	By 2026, reduce fleet-wide water consumption (withdrawals minus discharge) by 20 million m^3 or 40 per cent over the 2015 baseline	UN SDG Target 6.4: "By 2030, substantially increase water-use efficiency across all sectors and ensure sustainable withdrawals and supply of freshwater to address water scarcity and substantially reduce the number of people suffering from water scarcity"
Protecting nature and biodiversity	By 2024, assess and disclose nature-related risks and opportunities including TransAlta's dependencies and impacts on ecosystems, land, water and air	UN SDG Target 15.5: "Take urgent and significant action to reduce the degradation of natural habitats, halt the loss of biodiversity and, by 2020, protect and prevent the extinction of threatened species"
	Achieve zero biodiversity-related incidents[4]	

(1) TransAlta does not plan to use carbon credits to achieve its 2026 GHG emissions reduction target.

(2) The Company may choose to neutralize residual emissions from gas-fired generation through fuel switching, new technologies or nature-based solutions to achieve its 2045 net-zero target. For further information, refer to Climate Transition Plan in the Decarbonizing Our Energy Mix section of this MD&A.

(3) To calculate TransAlta's scope 3 GHG emissions, we rely on third-party data that is available only after the first quarter of each year. As a result, this target means reporting on 2023 scope 3 GHG emissions data in 2025 following the verification of data by independent third-party providers in 2024.

(4) This means biodiversity-related incidents that affected habitats and species included on the Red List of the International Union for Conservation of Nature and are classified as near-threatened, vulnerable, endangered and critically endangered.

ESG Alignment: Social

Sustainability goal	Sustainability target	Alignment with UN SDG Target or Future-Fit Business Benchmark
Reduce safety incidents	Achieve a Total Recordable Injury Frequency rate below 0.32 with a goal of 0.00	UN SDG Target 8.8: "Protect labour rights and promote safe and secure working environments for all workers, including migrant workers, in particular women migrants, and those in precarious employment"
Integrate sustainability into supply chain	By 2024, 80 per cent of our spend will be with suppliers that have a sustainability policy or commitment	UN SDG Target 12.7: "Promote public procurement practices that are sustainable, in accordance with national policies and priorities"
Support prosperous Indigenous communities	Support equal access to all levels of education for youth and Indigenous peoples through financial support and employment opportunities	UN SDG Target 4.5: "By 2030, eliminate gender disparities in education and ensure equal access to all levels of education and vocational training for the vulnerable, including persons with disabilities, Indigenous peoples and children in vulnerable situations"
	Provide Indigenous cultural awareness training during the onboarding of all new TransAlta employees	UN SDG Target 12.8: "By 2030, ensure that people everywhere have the relevant information and awareness for sustainable development and lifestyles in harmony with nature"

ESG Alignment: Governance

Sustainability goal	Sustainability target	Alignment with UN SDG Target or Future-Fit Business Benchmark
Strengthen gender equality	Achieve 50 per cent female representation on the Board by 2030	UN SDG Target 5.5: "Ensure women's full and effective participation and equal opportunities for leadership at all levels of decision making in political, economic and public life"
	Achieve at least 40 per cent female employment among all employees of the Company by 2030	
	Maintain equal pay for women in equivalent roles as men	
Demonstrate leadership on ESG reporting within financial disclosures	Maintain our position as a leader on integrated ESG disclosure through increased annual alignment with leading sustainability disclosure frameworks	UN SDG Target 12.6: "Encourage companies, especially large and transnational companies, to adopt sustainable practices and to integrate sustainability information into their reporting cycle"

ESG Alignment: Environmental and Social

Sustainability goal	Sustainability target	Alignment with UN SDG Target or Future-Fit Business Benchmark
Coal transition	No further coal generation by the end of 2025 with 100 per cent of our owned net generation capacity to be from renewables and gas	UN SDG Target 7.1: "By 2030, ensure universal access to affordable, reliable and modern energy services"
Clean energy solutions for customers	Develop new renewable projects that support customer sustainability goals to achieve both long-term power price affordability and carbon reductions	UN SDG Target 7.2: "By 2030, increase substantially the share of renewable energy in the global energy mix"

Decarbonizing Our Energy Mix

ESG is more than a business strategy at TransAlta; it is a competitive advantage. Sustainability is one of our core values; therefore, we strive to integrate climate change into governance, decision-making, risk management and our day-to-day business operations. The outcome of our climate change focus is continuous improvement on key climate-related issues and ensuring our economic value creation is balanced with a value proposition for the environment and people.

We recognize the impact of climate change on society and our business both today and into the future. Our renewable energy journey began 112 years ago when we built the first hydro assets in Alberta, which still operate today. In 1993, we began operating our first wind facility, which was the first commercial wind facility in Canada; in 2014, acquired our first solar facility; and, in 2020, constructed our first battery storage facility. Today, we operate 57 renewable facilities across Canada, the US and Australia.

Our reporting on climate change management has been guided by the TCFD recommendations since 2018. In 2023, we adopted guidance from IFRS S2, which is based on the TCFD recommendations with industry-specific climate metrics based on the SASB standards. IFRS S2 and TCFD help inform discussion and provide context on how climate change affects our business.

Strategy and Risk Management

Climate Change Strategy

As described in the following sections, our risks and opportunities assessment and climate scenarios analysis support the development and continuous improvement of our climate change strategy. We actively monitor and manage climate-related risks and opportunities as part of our overall business strategy to ensure we remain resilient across scenarios.

TransAlta remains committed to creating a path to resiliency in a decarbonizing world in support of the goals adopted under the Paris Agreement, and the goals adopted during subsequent international climate meetings. Our strategy is focused on the operation of our existing assets (wind, hydro, solar, natural gas, battery storage and transition-coal), the phase-out of coal-fired electricity generation, and the development of renewable energy and storage projects. Our customers are increasingly integrating ESG risk into their business decisions; therefore, we see an advantage in growing our renewable power business to support our customers' sustainability goals. Our investments and growth in renewable energy are highlighted by our portfolio of renewable energy-generating assets. From 2000 to 2023, we grew our nameplate renewables capacity from approximately 900 MW to over 2,900 MW. Today, our diversified renewable fleet makes us one of the largest renewable power producers in North America, one of the largest producers of wind power in Canada and the largest producer of hydro power in Alberta.

Another way we contribute to our customers' sustainability goals is through environmental attributes. The environmental attributes that we generate include carbon offsets, renewable energy credits and emission offsets. Our customers can use environmental attributes to lower compliance costs attributed to carbon policies or renewable portfolio standards. Furthermore, environmental attributes can help achieve voluntary corporate sustainability or carbon reduction goals. To combat the challenges of renewable energy intermittency, we continue to invest in battery storage and evaluate the role of natural gas to provide increased reliability and flexibility.

In 2020, we launched WindCharger, a "first-of-its-kind in Alberta" battery storage project that stores energy produced by our Summerview II wind facility and discharges electricity onto the Alberta grid during system supply shortages, as well as providing critical system support services to the system operator. This project received co-funding from Emissions Reduction Alberta. Further, in 2021, we agreed to provide solar electricity supported with a battery energy storage system to BHP Nickel West through the construction of the Northern Goldfields hybrid solar project in Western Australia. The Northern Goldfields solar and battery storage facilities were commissioned in 2023 and are expected to reduce BHP's scope 2 GHG emissions at its Nickel West operations by 12 per cent. In 2022, TransAlta entered into an agreement for the expansion of the Mount Keith 132kV transmission system. The expansion is underway, with expected completion in the first quarter of 2024. In 2023, TransAlta's early-stage development pipeline included in excess of 1 GW from four energy storage projects in Canada.

In support of our own path to build resilience to climate change, we have taken significant steps to reduce our carbon footprint over the last several years. In 2021, we adopted a more stringent climate-related target to reduce 75 per cent of our scope 1 and 2 GHG emissions by 2026 from a 2015 base year. This target covers 100 per cent of TransAlta's operating assets and is estimated to align with the electricity sector decarbonization pathway to limit global warming to 1.5°C, as one of the Paris Agreement goals. Furthermore, we adopted a long-term climate-related target to achieve net-zero for 100 per cent of TransAlta's scope 1 and 2 GHG emissions by 2045. This ambitious target aligns us with the Canadian Net-Zero Emissions Accountability Act to achieve net-zero emissions by 2050.

We are also taking strategic steps to decarbonize the power sector and support the energy transition. In 2021, we set out clear targets under the Clean Electricity Growth Plan. Since 2021, the Company added 800 MW of new capacity and acquired TransAlta Renewables (1.2 GW) and North Carolina Solar (122 MW). In 2023, our Clean Electricity Growth Plan was updated to continue our priorities. By 2028, the plan will see the Company execute on an incremental 1.75 GW of renewables growth and a 10 GW growth pipeline. In 2025, we will retire our single remaining coal unit, located in the US, to complete TransAlta's transition away from coal generation.

To date, we have retired 4,664 MW of coal-fired generation capacity since 2018 while converting 1,659 MW to natural gas. Comparatively, our converted natural gas units' CO2 intensity is approximately 57 per cent less than coal generation. Repurposing the facilities rather than decommissioning them reduces the cost and emissions associated with new construction and aligns with the UN SDGs, specifically "Goal 9: Industry, Innovation and Infrastructure." The completed conversions and the closure of the Highvale coal mine also contribute to the goals of the Powering Past Coal Alliance, which TransAlta joined in 2021 at COP26.

We actively engage policymakers and stakeholders on how to facilitate a transition where the electricity systems we serve can reach net-zero emissions while maintaining reliability. We will continue investing in renewables and assessing the best options to deliver energy storage, including incorporating learnings from our industrial-scale battery into our Company strategy and sharing those learnings with government. At the same time, natural gas will play an essential role in the electricity sector, providing dispatchable generation to support current system demands and a smooth energy transition. We always seek energy-efficiency improvements and opportunities to achieve emissions reductions at competitive costs. Further, we are committed to investing in climate change mitigation solutions to maximize value for our shareholders, customers, local communities and the environment.

Climate Transition Plan

A climate-related transition plan describes how a company aims to minimize climate-related risks and increase opportunities, in alignment with IFRS S2 and TCFD. In 2023, TransAlta reviewed and updated its Climate Transition Plan, which lays out our approach to reducing operational and value chain emissions to deliver net-zero operations by 2045. In addition, our Climate Transition Plan includes sustainable finance and inclusive transition actions reflecting TransAlta's commitment to a successful transition toward a low-carbon economy. For further information, refer to Sustainable Finance in the Decarbonizing Our Energy Mix section of this MD&A and Inclusive Transition in the Engaging with Our Stakeholders to Create Positive Relationships section of this MD&A.

Our Climate Transition Plan defines TransAlta's past, short-term (2024-2025) and medium- to long-term actions (beyond 2026). For each of these actions, we assessed our ability to control ("C") intended outcomes, partner ("P") with stakeholders to drive outcomes or influence ("I") outcomes that will help us achieve our decarbonization targets.

The highest level of climate change oversight, including the actions of our Climate Transition Plan, is at the Board level. For further information, refer to Oversight by the Board of Directors in the Climate Change Governance section of this MD&A. Information on executive compensation linked to climate-related targets is described in ESG-Linked Compensation in the Building a Diverse and Inclusive Workforce section of this MD&A. Metrics and targets supporting our Climate Transition Plan, including climate-related financial metrics, are described in Climate Change Metrics and Targets in the Decarbonizing Our Energy Mix section of this MD&A.

Delivering Net-Zero Operations by 2045

	Past actions	Short-term actions (2024-2025)	Medium to long-term actions (2026 +)
Hydro	Became the largest producer of hydro power in Alberta (C)	Advance 1500 MW of early-stage wind and solar projects in all jurisdictions (C) Complete development and commence construction on 100 MW wind project in Canada (C)	Deliver an incremental 1.75 GW of clean electricity capacity by 2028 (C) Deploy approximately $3.5 billion of growth capital by 2028 (C) Expand our growth pipeline to 10 GW by 2028 with focus on renewables and storage (C)
Wind and Solar	From 2000 to 2023, we grew our nameplate renewables capacity by approximately 2,000 MW (C)		
Battery Storage	First battery storage facility delivered in 2020 (C) In 2023, completed the construction of a 48 MW solar and battery storage system in Australia (C)	Complete development and commence construction on 180 MW battery storage in Canada (C) Evaluate and deploy battery storage alongside renewable facilities where appropriate (C)	
Natural Gas	Completed our coal-to-gas conversions in Canada in 2021 (C) Converted 1,659 MW from coal to natural gas since 2018 (C)	Operate simple-cycle, combined-cycle and cogeneration facilities in Canada, the United States and Australia (C) Assess deployment of nature-based or engineered solutions to neutralize unabated gas-fired generation where appropriate (C) Evaluate use of renewable and low-carbon natural gas (C)	Neutralize residual emissions from gas-fired generation through fuel switching, new technologies or nature-based solutions (C)
Emerging Abatement Technologies and Solutions	Started exploring new technologies such as storage, hydrogen and carbon capture (P) In 2023, continued to support the development of low-cost, low-emissions hydrogen production through $2 million investment in a Canadian-based venture (P) In 2023, started partnership with leading global companies to target early-stage revolutionary technologies through a US$25 million investment in a deep decarbonization fund (P) In 2023, started an electric vehicle pilot project in our hydro operations (C)	Identify the next generation of power solutions and technologies and potential for parallel investments in new complementary sectors by the end of 2025 (P) Assess ways to support customers with broader decarbonization technologies beyond electrification (P) Identify opportunities to partner, pilot and deploy novel, net-zero generation technologies (P) Assess and deploy GHG removal technologies where appropriate (C) Evaluate the electrification of our vehicle fleet (C)	Deploy new net-zero generation technologies and solutions where appropriate (C) Choose materials, products and processes that generate fewer GHG emissions, mainly through energy savings (C) Evaluate the electrification of our vehicle fleet (C)
Energy Transition (Coal)	Retired 4,664 MW of coal-fired generation capacity since 2018 including ending coal generation in Canada in 2021 (C)	Continue to execute reclamation work at our coal mines (C) Contribute to a circular economy through mining waste reuse or by-product sales (C)	Cease coal generation by 2026 (C) Complete full reclamation in Washington State by 2040 and in Alberta by 2046 (C)

Legend: (C) Control intended outcomes, (P) partner with stakeholders to drive outcomes, and (I) influence outcomes that will help us achieve our decarbonization targets.

Delivering Net-Zero Operations by 2045 (Continued)

	Past actions	Short-term actions (2024-2025)	Medium to long-term actions (2026 +)
Supply Chain	Enhanced supplier management functionality within the corporate procurement system (C)	Develop ESG criteria for supply chain engagement (C) Understand direct suppliers, GHG emissions profile and targets (C) Incorporate ESG data reporting capability in corporate procurement system (C)	Engage with suppliers to explore enhancement of their GHG emissions reduction targets (I) Set direction for engaging suppliers with GHG emissions reduction targets (C)
Value Chain	Disclosed range of scope 3 GHG emissions at company level (C)	Update scope 3 GHG emissions reporting methodology (C) Verify and disclose 80 per cent of our total scope 3 emissions (C)	Consider scope 3 GHG emissions targets (C)
Sustainable Finance	In 2021, converted existing $1.3 billion loan into a Sustainability-Linked Loan aligned with GHG emissions reduction and female employment targets at the company level (C) In 2021, secured $173 million green bond financing for eligible wind project in Alberta (C) In 2022, issued US$400 million Senior Green Bonds for eligible renewable energy and energy-efficiency projects (C) Linked ESG performance to employees' and executive remuneration (C)	Continue to evaluate the use of sustainable or green financing instruments to fund renewable energy and battery storage projects (C) Link ESG performance to employees' and executive remuneration (C)	Continue to evaluate the use of sustainable or green financing instruments to grow our renewables and storage capacity (C) Link ESG performance to employees' and executive remuneration (C)
Inclusive Transition	Developed a five-year Equity, Diversity and Inclusion (ED&I) strategy (C) Conducted ED&I census to help drive a greater sense of belonging for all employees (C) Set employee engagement and ED&I targets as part of ESG-linked compensation (C) In 2023, launched two employee resource groups (C) In 2023, provided Indigenous cultural awareness training to all employees (C) In 2015, announced community investment of US$55 million over 10 years to support energy efficiency, economic and community development and education and retraining initiatives in Washington State (P) In 2016, agreed to invest in the communities impacted by the phase-out of coal generation in Alberta (P)	Expand number of employee resource groups available (C) Adapt workplaces to incorporate structural changes for inclusive work environments (C) Deliver year-round ED&I learning and awareness, and celebration campaigns (C) Continue energy transition investment in Washington State communities of up to US$55 million by 2025 (P) Continue to invest in the communities impacted by the phase-out of coal generation in Alberta (P) Strengthen Indigenous relations focused on community engagement and consultation, community investment and partnership opportunities (P) Promote supplier diversity in our operations (C)	Enhance recruitment and retention of female employees to achieve gender-based targets (C) Maintain succession practices to increase female representation at senior management level (C) Increase female representation in Generation by encouraging women to pursue a career in electricity (C) Enhance opportunities for diverse suppliers in our procurement processes (C) Continue to enhance our Indigenous relations focused on partnership opportunities with local communities (P) Ongoing support to local community organizations aligned with our community investment pillars where we operate and grow communities (P)

Climate Change Governance

Climate-related risks and opportunities can significantly impact our business, especially regulatory changes and shifting customer preferences toward lower-carbon energy. Therefore, we actively manage risks and opportunities so that we can continue to grow and achieve our goals. Climate-related issues are identified at every level of management, including the Board, executive team, business units and corporate functions (for example, government relations, regulatory, emissions trading, sustainability, commercial, customer relations, investor relations). Ensuring climate-related issues are acknowledged and addressed at the most senior levels of the Company (including at the Board and executive level) has allowed us to establish actionable emissions reduction targets and grow our generation capacity through renewable energy and storage.

Oversight by the Board of Directors

The highest level of climate change oversight is at the Board level, with specific oversight of certain aspects of the Company's response to climate change being delegated to our Governance, Safety and Sustainability Committee ("GSSC"), our Audit, Finance and Risk Committee ("AFRC") and our Investment Performance Committee ("IPC") of the Board.

Meeting quarterly, the GSSC assists the Board in monitoring and assessing compliance with climate change regulation and reporting. The GSSC receives management reports on changes in climate-related legislation and the potential impact of policy developments on TransAlta's business. The GSSC then supports the Board in assessing and overseeing Company-wide climate change strategies, policies and practices. The GSSC also reviews environmental protection guidelines, including with respect to GHG mitigation, and considers whether our environmental procedures are being effectively implemented.

The AFRC and IPC also play a role in managing TransAlta's climate-related risks and opportunities. The AFRC assists the Board in overseeing the integrity of our consolidated financial statements and considers climate risks and opportunities as it relates to our financial decision-making. Further, the AFRC is responsible for approving our Commodity and Financial Exposure Management policies and reviewing quarterly ERM reporting. The IPC considers and assesses risks related to capital investment projects, including overseeing climate risk assessments and mitigation plans. As a result, climate-related capital expenditures, acquisitions and budgets are reviewed by the AFRC and IPC on a case-by-case basis.

The Board reviews and updates the Company's strategy annually. In 2023, the Board's strategic planning sessions included climate-related issues considering growth initiatives and strategies, capital allocation, ESG policy development and other matters. Our Board is composed of individuals with a mix of skills, knowledge and experience critical to our strategy success and business growth. In 2023, three of our 13 Board members identified environment/climate change among their top four relevant competencies. Given the breadth of experience and skills of each director, the skills matrix lists only the top four competencies possessed by each director nominee based on the Board's assessment and each director's self-evaluation. The criteria used to assess competence of Board members on climate-related issues includes the knowledge of corporate responsibility practices and the constituents involved in sustainable development practices, including as it pertains to climate change.

For further information regarding Board members competence on climate-related issues, refer to TransAlta's Management Proxy Circular.

Role of Senior Management

TransAlta's President and CEO maintains the highest level of oversight on climate-related issues at the executive level. Senior management of the Company, including our President and CEO, provide the Board with updates on climate-related risks and opportunities to inform business strategy and ensure alignment with TransAlta's GHG emissions reduction goals.

Our business units and corporate functions work closely together to support the executive team in understanding climate-related risks and opportunities, including legislative developments. Our executive team reviews such risks and opportunities quarterly and reports to the GSSC and AFRC, as applicable.

At the business unit level, climate change risks are identified through our Total Safety Management System, asset management function and systems, energy and trading business, communication with stakeholders, active monitoring and participation in working groups.

Notably, we tie a component of executive compensation to reducing GHG emissions and climate change management. We link our annual incentive plans (short-term incentive and long-term incentives) to our strategic goals. Our strategic goals include growing renewable energy, reducing GHG emissions and supporting our customers' sustainability goals to decarbonize through on-site low carbon energy generation.

For further information on incentives for ESG performance, refer to the discussion on ESG-Linked Compensation in Building a Diverse and Inclusive Workforce section of this MD&A.

Climate Scenarios

In 2021, we conducted climate scenario analysis to understand risks and opportunities and assess our strategy's resiliency under several potential future climate scenarios. The analysis utilized scenarios from the International Energy Agency's ("IEA") 2020 World Energy Outlook, a large-scale simulation model designed to replicate how energy markets function. We used three scenarios: Stated Policies ("STEPS"); Sustainable Development ("SDS"); and Net-Zero Emissions by 2050 ("NZE").

In STEPS, the energy system has no major additional climate and environmental policies enacted by government(s). STEPS assumes that carbon pricing continues in Canada while no carbon price is set in the US or Australia. STEPS also assumes that the power sector reduces emissions by 45 per cent by 2040 while natural gas generation capacity increases. Finally, STEPS is limited to the deployment of commercial-ready technologies, including wind and solar.

In SDS, the goals of the Paris Agreement (2015) are achieved, resulting in net-zero emissions by 2070. The SDS assumes a rapid increase in clean energy policies and investments that position the energy system to also achieve key UN SDGs. In SDS, all current net-zero pledges are achieved and there are extensive efforts to reduce emissions. SDS assumes that carbon pricing continues in Canada and is set in the US and Australia. It also assumes that the power sector reduces emissions by 90 per cent by 2040 while natural gas capacity remains stable into 2030 and declines toward 2040. Finally, SDS assumes that beyond wind and solar, the energy system relies on batteries, storage and some level of carbon capture, utilization and storage ("CCUS") and hydrogen.

NZE represents a pathway for the global energy sector to achieve net-zero emissions by 2050. This scenario also assumes key energy-related SDGs are achieved through universal energy access by 2030 and major improvements in air quality. NZE is built upon the idea that a global increase in electrification supports the journey to net-zero. It assumes that an aggressive carbon price is set in Canada, the US and Australia. It also assumes the power sector reaches net-zero emissions by 2035 in advanced economies while natural gas capacity is stable to 2030 and declines significantly into 2040. Like the SDS, NZE assumes that beyond wind and solar, the energy system relies on batteries, storage and some level of CCUS and hydrogen.

In 2023, we reviewed the findings from the climate scenario analysis and updated the management response accordingly.

Key Climate Scenario Findings

Using climate scenarios, we analyzed the resiliency of our business and determined specific risks and opportunities for our individual assets. All three scenarios present opportunities for TransAlta's growth related to renewables, storage solutions and ancillary services. The scenario analysis found that our wind and solar assets have the highest prospects for growth, which aligns with our growth strategy. Under all scenarios, hydro remains a valuable asset as it allows for expansion to include storage.

The following sections highlight TransAlta's top risks, opportunities and management response across all scenarios.

Top Identified Climate-Related Risks by Scenario

	Increased competition	Decreased demand of natural gas electricity	Increased operational costs
Description	Subsidies/funds available for clean energy transition increase as governments aim to grow installed capacity of renewables to meet rising electricity demand and compensate for the closure of carbon-intensive power plants. In Canada, it is expected that major grid decarbonization investments will flow into Alberta as most other provincial markets are heavily regulated and/or are already low carbon. This will increase competition in the merchant market, making a large part of the generating fleet frequently bid at zero, driving down the average price of dispatched electricity. Simultaneously the cost of renewables, expected to decline across all scenarios, decreases the capital barrier to entry. These combined factors will increase competition for TransAlta. The IEA scenarios do not provide clear indication of electricity pricing and how it can be affected by increased competition. As such, this remains a point of uncertainty. Some structural market changes may be required to guarantee returns for power generators and successfully decarbonize the grid.	Demand for power from natural gas declines as the market shifts towards cleaner power with gas shifting to a reliability backstop role. An additional decline from Canadian oil and gas customers can occur as oil production levels drop under NZE and SDS. The transition to a lower-carbon world will likely result in volatility and market uncertainty. Natural gas power may be necessary to provide power in the transition if the pace of decarbonization is slower than expected in the scenarios or if grid-scale storage solutions do not develop/commercialize as modelled. In these cases, with coal phased out, natural gas assets will be relied on for baseload generation. This means that natural gas assets may still play a role for a smooth and efficient energy transition. Optimization of natural gas assets is required, and additional investments need to be assessed with caution to consider the pace of decarbonization and consequent risk of decreased demand for natural gas power.	Carbon price increases the cost of natural gas operations. Additional mandated emissions reductions could force remaining plants to invest in technologies like CCUS, increasing the operating costs for natural gas plants further. Natural gas assets in the US and Australia face less risk compared to assets in Alberta as they are contracted and can pass down carbon costs to their clients. Current and anticipated regional carbon pricing monitoring is required to plan and assess increases in operational costs and impacts on new projects and investments.

	Increased competition	Decreased demand of natural gas electricity	Increased operational costs
NZE	By 2040, renewables are expected to comprise over 85 per cent of the total electricity generation in the regions we operate. This surge in renewables will increase competition and drive electricity pricing down depending on availability and the cost of energy storage. The change in electricity prices and increased market uncertainty are expected to impact our profits.	The share of natural gas electricity generation is expected to decline over 50 per cent in the regions in which we operate by 2040 compared to 2019 levels. This lower demand for natural gas power is expected to impact our natural gas assets if no management responses are implemented.	Higher operational costs driven by an increase in carbon price to US$205/tonne CO2e by 2040 in all our operating regions (advanced economies under IEA scenarios) and lower operational capacity is expected to impact the profits from our natural gas assets.
SDS	Fewer subsidies/funds are expected under this scenario compared to NZE. However, renewable costs will still decline approximately 10 per cent in wind and 55 per cent in solar by 2040 compared to 2019 levels. This decline with some level of subsidy will increase competition and potentially decrease electricity prices, which is expected to impact our profits.	Natural gas electricity generation still falls over 50 per cent in North America while remaining flat in Australia by 2040 when compared to 2019 levels. Demand for natural gas power is expected to decrease at a slower pace than under NZE. This could potentially impact our natural gas assets if no management responses are implemented.	Increase in operational costs would happen at a slower rate compared to NZE but carbon costs are still expected to reach US$140/tonne CO2e by 2040 in all of our operating regions. This could potentially impact the operational capacity and profits from our natural gas assets, depending on the ability to pass carbon prices on through our contracts.
STEPS	While minimal subsidies are expected and the cost of entry will not decline at the same rate as SDS or NZE, renewable costs are still expected to decline approximately 8 per cent in wind and 45 per cent in solar by 2040 compared to 2019 levels. This will still cause an increase in competition that is expected to be offset by additional electricity demand and therefore it is not expected to impact our profits.	Natural gas electricity generation is expected to increase over 15 per cent in the regions in which we operate by 2040 compared to 2019 levels. These changes are not expected to affect our natural gas assets.	Operational costs are not expected to significantly increase under this scenario as only Canada sees a carbon price in 2040.
Management Response	Navigating the uncertainty around market dynamics (structure, pricing and competition), government policies and planning is critical for TransAlta. We use hedging and PPAs to stabilize pricing and are planning on leading clean energy growth in the regions in which we operate. See more details of our strategy and risk management under the Climate Strategy section and the Managing Climate Change Risks and Opportunities section of this MD&A.	Optimize gas assets to maximize value and cash flows to support renewables and storage growth. Our converted natural gas units' CO_2 intensity is approximately 57 per cent less than coal generation. Repurposing the coal facilities rather than decommissioning them reduces the cost and emissions associated with new construction and aligns with the UN SDGs, specifically "Goal 9: Industry, Innovation and Infrastructure." In parallel, we continue growing our renewable fleet; by the end of 2025 we will have achieved a 100 per cent portfolio mix of renewables and natural gas.	We have taken significant steps to reduce our carbon footprint. Since 2015, we have reduced scope 1 and 2 GHG emissions by 66 per cent. By 2026, we have a commitment to reduce scope 1 and 2 GHG emissions by 75 per cent from 2015 base year and plan to achieve net-zero emissions by 2045. Further, our corporate functions apply regionally specific carbon pricing, both current and anticipated, as a mechanism to manage future risks of uncertainty in the carbon market.

Top Identified Climate-Related Opportunities by Scenario

	Renewables become major energy source	New technology development
Description	Opportunities to grow the renewable fleet exist across all scenarios. Renewable assets (hydro, wind, solar) are expected to become the default form of generation with demand for power from these types of assets increasing. Hydro is likely to grow in value given increased renewables penetration and the need for reliable zero-emitting generation. This can make hydroelectric power a stronger source of baseload electricity in many regions. The decreasing cost of renewables also facilitates the growth of a renewable fleet, especially under NZE and SDS.	Opportunities for development of battery or hydroelectric storage systems and ancillary services exist across all scenarios as renewable energy continues to penetrate the grid. Developments in these areas are required to keep electricity flowing when the renewables in a region are not producing. Storage is especially anticipated to play an important role in the energy transition. Cost-competitive battery storage enables greater adoption of renewables.
NZE	A growth of renewable electricity generation of approximately 950 per cent is expected by 2040 compared to 2019 levels. This results in renewables comprising more than 85 per cent of the electricity generation in the regions in which we operate. The transition of hydro to baseload capacity is expected to create upside for TransAlta. An increase in TransAlta's renewable capacity and demand are expected to enable growth and higher revenues.	Increased revenues through access to new and emerging markets are expected to enable growth and higher revenues under NZE. With more than 85 per cent of electricity in areas in which we operate made up of renewables, there will be big steps forward in storage and ancillary services technologies. Storage capacity is expected to grow to approximately 250 GW in the US by 2040.
SDS	A growth of renewable electricity generation of approximately 550 per cent is expected by 2040 compared to 2019 levels. This results in renewables comprising more than 75 per cent of the electricity generation in the regions in which we operate. An increase in TransAlta's renewable capacity and demand are expected to enable growth and higher revenues.	Increased revenues through access to new and emerging markets are expected to enable growth and higher revenues under SDS. A lower share of renewables than in NZE will allow swing production to remain present; however, growth in ancillary and storage capacity will still be needed to support the market. Storage capacity is expected to grow to approximately 110 GW in the US by 2040.
STEPS	STEPS growth is muted relative to the other scenarios but still sees a growth of renewables of 280 per cent by 2040 compared to 2019 levels. This growth will allow approximately 50 per cent of electricity generation to come from renewables in areas in which we operate by 2040. An increase in TransAlta's renewable capacity and demand are expected to enable growth and higher revenues.	Access to new and emerging markets would be limited under this scenario compared to NZE and SDS. While growth in renewables is expected, the need for new technologies is not a necessity in this market and may not be profitable. Therefore, our revenues are not expected to be affected.
Management Response	Our renewable energy commitment began more than 100 years ago when we built the first hydro assets in Alberta, which still operate today. We now operate 57 renewable facilities across Canada, the US and Australia. By the end of 2028, we expect 70 per cent of our EBITDA to be derived from renewables. Our strategy is focused on the operation of our existing assets (wind, hydro, solar, gas, storage and coal) and the development of renewable energy, storage and responsive and flexible natural gas generation for reliability. Our investments and growth in renewable energy are highlighted by our portfolio of renewable energy-generating assets. From 2000 to 2023, we grew our nameplate renewables capacity from approximately 900 MW to over 2,900 MW. Today, our diversified renewable fleet makes us one of the largest renewable producers in North America, one of the largest producers of wind power in Canada and the largest producer of hydro power in Alberta.	To leverage this opportunity and combat the challenges of renewable energy intermittency, we continue to invest in battery storage. In 2020, we launched WindCharger, a "first of its kind in Alberta" battery storage project that stores energy produced by our Summerview II wind facility and discharges electricity onto the Alberta grid during system supply shortages. Further, in 2021, we agreed to provide renewable solar electricity supported with a battery energy storage system to BHP Nickel West through the construction of the Northern Goldfields solar project in Western Australia. This project was completed in November 2023 and will support BHP in meeting its emissions reduction targets and delivering lower-carbon, sustainable nickel to its customers. In 2023, TransAlta's early-stage development pipeline included four energy storage projects in Canada with a total capacity in excess of 1 GW.

NZE: The most significant risks include increased competition, decreased demand for natural gas and increased operational costs due to increased carbon pricing and emissions reduction mandates. The most significant opportunities include a shift toward renewables as the default energy source and new technology developments, including battery storage systems and ancillary services. It is worth noting that there are additional risks and opportunities for TransAlta under NZE. For example, changes in how energy market services are offered could positively or negatively impact our business. Further, as carbon credit policies evolve, so will our ability to use credits. Lastly, as renewables become the primary energy source, a rethinking of ancillary services will be necessary but could create significant opportunities for TransAlta.

SDS: The risks and opportunities remain the same under SDS as NZE; however, the impacts are reduced as market changes are slower and less extreme. Renewables still become the primary electricity source and there are new technology opportunities, particularly in batteries. Natural gas electricity demand still declines by 2040. Carbon pricing exists in the US and Australia, but the price is reduced compared to NZE. Lastly, a reevaluation of ancillary services still presents an opportunity for TransAlta.

STEPS: Under STEPS, renewable generation sees significant growth but does not become the predominant energy source. Implementing new technologies is much slower and the demand for batteries is reduced. The demand for natural gas electricity does not decline and there are no large-scale market changes making services, pricing and ancillary services more stable. This removes the risk associated with natural gas electricity demand but eliminates the opportunity for growth in ancillary services. Physical risks become more relevant under this scenario than transitional risks.

To mitigate risks and capitalize on opportunities, we have developed climate signposts to monitor the evolution of future climate scenarios. Signposts are indicators that suggest the likelihood of a particular climate scenario. Examples of signposts include directional change in carbon and oil prices. The findings from the climate scenarios and these signposts work alongside our sustainability metrics and targets to inform the evolution and resiliency of our Company's strategy and financial planning, risk management, opportunity assessment and planning for uncertainty.

Managing Climate Change Risks and Opportunities

We actively monitor and manage climate-related risks through our Company-wide ERM processes. In 2021, we established a formal process to review specific risks using climate scenario analysis. As previously mentioned, climate change risks and opportunities are addressed at each of the Board level, executive and management level, business unit level and through our corporate functions. The business units and corporate functions work closely together and provide information on risks and opportunities to management, the executive team and the Board.

Climate change risks at the asset or business unit level are identified through our Total Safety Management System, asset management function and systems, energy and trading business, communication with stakeholders, active monitoring and participation in working groups. All identified material risks are added to our ERM register and scored based on likelihood and impact. We do not consider risks in isolation and major risks are the focus of management response and mitigation plans. Further discussion can be found in Reporting in the Governance and Risk Management section of this MD&A.

We divide our climate change risks into two major categories as per IFRS S2 and TCFD guidance: (i) risks related to the transition to a lower-carbon economy; and (ii) risks related to the physical impacts of climate change.

Transition Risks to a Lower-Carbon Economy

We actively aim to understand and manage the impact of climate change on our business as the world shifts to a lower-carbon society.

Policy and Legal Risks

Changes in current environmental legislation do have, and will continue to have, an impact upon our operations and our business in Canada, the US and Australia.

For a more detailed assessment of policy and regulatory risks, refer to the Governance and Risk Management section of this MD&A.

Canada

The Government of Canada has set out ambitious objectives for carbon emissions reduction, including achieving a 40 to 45 per cent national emissions reduction over 2005 levels by 2030, a net-zero electricity grid by 2035 and a net-zero national economy by 2050. The Government plans to rely on several policy tools to achieve its emissions objectives, including carbon pricing, emissions performance regulations, funding for industrial energy transition, a Clean Fuel Regulation and incentives for consumers.

Canada's provinces have significant jurisdiction over their respective electricity sectors and play an important role in setting carbon pricing policy and emissions performance standards, as well as developing and operating their own funding and incentive programs, subject to the federal government's authority to set national carbon pricing standards. Negotiation to align carbon pricing, funding and regulatory standards will likely require significant effort and create the risk of tension and misalignment between federal and provincial governments.

Risks

- Escalation in carbon prices and emissions performance regulation may impact TransAlta's natural gas generation fleet in Canada as governments escalate policy stringency to meet 2030, 2035 and 2050 targets.
- Increased government funding for industrial energy transition may create out of market incentives for competing generation.
- Regulatory incentives, including emissions reduction crediting, may create out of market incentives for competing generation.
- Lack of federal/provincial coordination with respect to climate policy and regulation may lead to investment uncertainty.

Opportunities

- Independent estimates suggest that achieving Canada's climate targets will require a minimum of twice Canada's current non-emitting generation. This presents strong policy alignment with TransAlta's Clean Electricity Growth Plan. Further, we continue to see strong private sector demand for contracted zero emissions generation to meet corporate sustainability goals.
- Government funding for innovative technology to reduce emissions from the electricity sector offers TransAlta the potential opportunity to gain project support for uneconomic new technologies, which will enable the Company to grow its ESG and policy-aligned generation and energy storage fleet.
- Government support for industrial electrification and consumer incentives mandates for electrification, such as for the purchase of electric vehicles, will grow the electricity load over time and create new opportunities for contracted clean electricity generation.

Management Response

- TransAlta's Clean Electricity Growth Plan positions our company to meet the rapidly growing demand for clean electricity generation driven by customers and government policy.
- We are focused on developing and acquiring contracted assets that provide long-term certainty with respect to revenue and eligibility for government incentive programs. TransAlta actively assesses available government renewable energy tax legislation and programs to maximize, wherever possible, access to project incentives.
- Our clean and contracted growth reduces the proportional Company exposure to potential policy and regulatory decisions that negatively impact natural gas generation.
- Our coal-to-gas facilities fit within government plans to continue providing reliable and competitively priced electricity for consumers and industry.
- Our remaining natural gas facilities (non-coal-to-gas) operate under contract, reducing TransAlta's exposure to changes in carbon pricing.
- TransAlta actively engages with the federal and provincial governments in Canada to inform and influence policy development to ensure that our generating fleet continues to serve our customers as the country undertakes a broader energy transition.
- We actively work, both directly and through industry associations, to encourage governments to adopt a level playing field within funding and crediting programs so that all new emerging technology projects receive equitable government incentives and funding.
- TransAlta actively engages with all relevant Canadian governments to seek policy alignment across carbon pricing and regulatory and funding programs to create the greatest possible degree of investment certainty.

United States

The US Government has set out ambitious objectives for carbon emissions reduction, including achieving a 50 to 52 per cent national emissions reduction over 2005 levels by 2030, a net-zero electricity grid by 2035 and a net-zero national economy by 2050. The US does not have a national carbon pricing regime but does offer federal incentives for renewable generation and energy storage.

State and regional climate and market policies have a significant impact on the pace of energy transition in the US with many governments operating under renewable portfolio standards and carbon pricing regimes. Similar to Canada, independent estimates suggest that the US will require substantial growth in zero-emissions generation to meet its national climate targets.

Risks

- TransAlta operates two thermal generating facilities in the US that could be subject to short-term climate policy changes, but our exposure to this policy risk is low (refer to Management Response below).
- Significant new federal incentives for clean energy could increase competition in the renewables and energy storage space.

Opportunities

- Achieving government climate goals and private sector sustainability commitments will require rapid and sustained growth in zero-emissions electricity generation over the coming decades. TransAlta's Clean Electricity Growth Plan is focused on providing renewable electricity to contracted customers in a manner that aligned with federal, state and private sector goals.
- US tax incentive programs offer significant support for new renewable and energy storage projects, making the US an attractive growth market.

Management Response

- TransAlta's single coal unit in Washington State is subject to a retirement agreement with the state government that exempts the facility from any carbon regulation prior to its end of life in 2025. TransAlta's cogeneration unit at Ada operates under a contract that reduces the Company's exposure to policy risk.
- Our Clean Electricity Growth Plan is focused on developing and acquiring contracted assets that provide long-term certainty with respect to revenue and eligibility for government incentive programs. TransAlta actively assesses available government renewable tax legislation and programs to maximize, wherever possible, access to project incentives.

Australia

The Australian Government has a 43 per cent national emissions reduction target over 2005 levels by 2030 and a goal to achieve a net-zero national economy by 2050. Decarbonization efforts have been centered on funding for clean technologies, upgrading the electricity grid to support more renewables, regulating and reporting of GHG emissions, and incentivizing zero-emissions vehicle adoption. Large GHG emitters are required to reduce their scope 1 emissions under the Australian Government's National Safeguard Mechanism ("SGM"). While the government has made recent changes to the SGM, these changes are not expected to have a material impact on TransAlta's assets. Australian state governments have all adopted net-zero goals and a number of states have interim targets for 2030 and 2040. These state policies are driving demand for zero-emissions electricity and energy storage.

Risks

- TransAlta's Australian natural gas assets may face policy risk related to changes in government policies but remain well positioned to mitigate those risks (refer to Management Response below).

Opportunities

- Our Clean Electricity Growth Plan is focused on building new, clean electricity generation in Australia and other markets. Government policies and funding programs are generally supportive of the types of projects contemplated within TransAlta's strategy.
- Strong corporate demand for clean electricity solutions in Australia's natural resource sectors present opportunities for TransAlta to leverage its existing expertise to help customers meet regulatory requirements and reach their decarbonization objectives.

Management Response

- Through our Clean Electricity Growth Plan, TransAlta continues to deliver clean electricity solutions to natural resource customers in Western Australia. Our growing suite of technologies, including renewables and energy storage, positions us to provide contracted solutions to customers focused on the need for reliable and sustainable energy.
- TransAlta also continues to assess opportunities to grow our clean energy generation in alignment with Australia's national and state climate goals.
- TransAlta's assets are predominantly contracted with an ability to pass through carbon compliance costs and serve remote industrial load. As a result, the Company faces reduced policy risk.

Technology Risks

Technological changes to support the low-carbon transition present both risks and opportunities for TransAlta. We evaluate existing and emerging impacts of technology through our Energy Innovation team and our ERM process. Examples of technology risks and opportunities include infrastructure changes (such as the shift to distributed energy and away from large-scale power generation infrastructure assets and projects) and digitization combined with greater adoption of energy efficiency (less use of our end product). Cost-competitive battery storage will enable greater adoption of renewables and a shift to a distributed power generation model. We continue to evaluate battery storage for its financial viability while monitoring the potential impact battery technology could have on natural gas power generation. In 2020, we completed our first battery storage (10 MW) project at one of our wind facilities in Southern Alberta. In 2023, we delivered a hybrid system of solar with battery storage (48 MW) in Western Australia. We continue to investigate the possibility of battery storage at our other facility locations. Our teams continuously adopt improved technology at each of our new developments, which helps protect our shareholder value and maintain reliable and affordable electricity delivery.

We are well-positioned to take advantage of technological opportunities in storage through hydro and/or battery power. We are also well-positioned to take advantage of advancements in renewable technologies as we build new facilities. We will continue monitoring new technologies such as storage, hydrogen and CCUS for future deployment.

For further information on technology and innovation, refer to the Enabling Innovation and Technology Adoption section of this MD&A.

Market Risks

Our major market risks are associated with our coal and natural gas assets. Increased costs for natural gas supply due, in part, to carbon pricing changes could impact our operating costs. We actively monitor market risks through our energy marketing and asset optimization teams and our ERM process. We manage the market risks to our coal assets by converting them to natural gas and plan to fully transition off coal by 2025. Further, our corporate functions apply regionally specific carbon pricing, both current and anticipated, as a mechanism to manage future risks of uncertainty in the carbon market. To simultaneously manage our risks and leverage market opportunities, we continue operating our hydro, wind and solar facilities and are investing in expanding our renewable energy fleet.

We currently have over 30 renewable projects that are either under construction or in the development stage. We are committed to growing our clean energy fleet. Further, we established Canadian, US and Australian clean energy growth teams. In 2023, the Company established a pipeline of potential growth projects in renewables that includes 280 MW of advanced-stage development projects along with 4,285 to 5,015 MW of projects in earlier stages of development. Our renewable fleet makes our overall portfolio more resilient to climate risk, provides increased flexibility in generation and creates incremental environmental value through environmental attributes. Lastly, we recognize the opportunity to grow our ancillary services, such as systems support, providing flexibility to the decarbonizing grid.

Reputation Risks

Negative reputational impacts, including revenue loss and reduced customer base, are evaluated through our ERM process. In the past, we experienced negative reputational impacts due to our coal operations, including a negative impact on the market price of our common shares. Our clear transition path away from coal mitigates this reputational risk. As consumer trends move in favour of renewable electricity, we are investing in a diversified mix of renewable generation and optimizing our natural gas fleet. We continue to actively monitor and manage reputational risks by delivering renewable power solutions while maintaining competitive costs and reliability.

Physical Risks of Climate Change

As we learn more about the physical risks associated with climate change, we continue to consider acute and chronic risks that could significantly impact our operations. We continue to investigate the physical impacts of climate change on our operating assets.

Acute Physical Risks

We have operating assets in three countries and varied geographic locations, many of which could be impacted by extreme weather events. We continuously evaluate the potential impact of acute climate change on our business. Our facilities, construction projects and operations are exposed to potential interruption or loss from environmental disasters (e.g., floods, strong winds, wildfires, ice storms, earthquakes, tornados, cyclones). A significant climate change event could disrupt our ability to produce or sell power for an extended period. Therefore, we strive to mitigate future impacts with climate adaptation solutions.

For example, our gas facility at South Hedland, Australia, is built with climate adaptation in mind. We designed the facility to withstand a category 5 cyclone (the highest cyclone rating). We have mitigated the risk of floods that can occur in the area by constructing the facility above normal flood levels. In 2019, a category 4 cyclone hit this facility but did not impact operations. We were able to continue generating electricity through the storm despite widespread flooding and the shutdown of the nearby port. In Canada, since the 2013 floods in Southern Alberta, we have implemented projects that increase the resilience of our hydro facilities to severe climate events. We have also modified operations at several of our facilities as per an agreement with the Government of Alberta. This reduces flood risk in the spring while also recognizing the potential for increased droughts as a result of climate change in the future. TransAlta continues to participate in multi-stakeholder groups developing options for climate resiliency across Southern Alberta.

For further information on weather-related risks, refer to Weather in the Progressive Environmental Stewardship section of this MD&A.

Chronic Physical Risks

We continuously investigate the physical impacts of longer-term shifts in climate patterns on our operating assets and actively integrate climate modelling into our long-term planning. For example, changes to water flow or wind patterns could impact our hydro and wind businesses and associated revenue generation.

Climate Change Metrics and Targets

Metrics and Targets

At TransAlta, climate change management and performance are a top priority. We established our climate-related goals and targets with reference to the UN SDGs. Over time, we have set ourselves apart with actions that demonstrate climate change leadership.

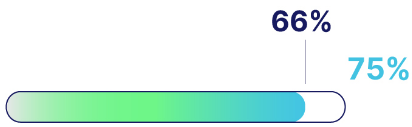
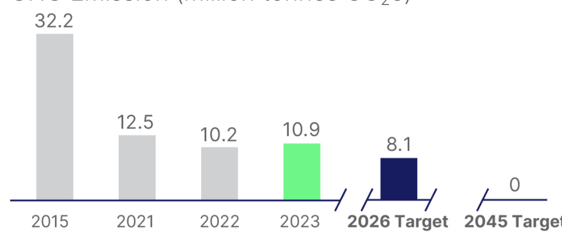
Progress towards our climate-related targets are presented below. As a result of our Clean Electricity Growth Plan being updated in November 2023, the below performance is assessed against our prior Clean Electricity Growth Plan announced in 2021.

Clean energy growth

Sustainability Target	Develop new renewable projects that support our customers' sustainability goals to achieve both long-term power price affordability and carbon reductions.(1)	No further coal generation; 100 per cent of our owned net generation capacity from renewables and gas.
Target Year	2025	2025
Progress	Renewables Growth 44% 2GW	Net Generation Capacity (renewable and gas) 90% 100%
Notes	Since 2021, we have added over 800 MW of new capacity through renewable projects such as Windrise (206 MW), Garden Plain (130 MW), Northern Goldfields Solar (48 MW), White Rock (300 MW) and Horizon Hill (200 MW). In November 2023, our Clean Electricity Growth Plan was updated to continue our priorities. By 2028, the plan will see the Company execute on an incremental 1.75 GW of renewables growth and a 10 GW growth pipeline.	In 2023, our owned net generation capacity from renewables and gas represented approximately 90 per cent of our total 6,425 MW owned net generation capacity. In 2021, we achieved full phase-out of coal in Canada. In the US, the remaining unit at Centralia is set to retire on Dec. 31, 2025.
UN SDG Alignment	Target 7.2: "By 2030, increase substantially the share of renewable energy in the global energy mix"	Target 7.1: "By 2030, ensure universal access to affordable, reliable and modern energy services".

(1) This includes the construction of new renewable projects (hydro, wind and solar) as part of the Company's Clean Electricity Growth Plan. This excludes acquisitions.

Emissions reduction

Sustainability Target	By 2026, achieve a 75 per cent reduction of scope 1 and 2 GHG emissions from a 2015 base year.	By 2045, achieve net-zero for 100 per cent of TransAlta's scope 1 and 2 GHG emissions.
Target Year	2026	2045
Progress	GHG Emissions Reduction 	GHG Emission (million tonnes CO_2e) 
Notes	We are well on track to achieve our target of 75 per cent scope 1 and 2 GHG emissions reductions by 2026. Since 2015, we have reduced scope 1 and 2 GHG emissions by 21.3 MT CO2e or 66 per cent.	In 2022, we adopted a more ambitious target to be net-zero by 2045. We believe our Clean Electricity Growth Plan supports achieving our net-zero target.
UN SDG Alignment	Target 13.2: "Integrate climate change measures into national policies, strategies and planning".	Target 13.2: "Integrate climate change measures into national policies, strategies and planning".

TransAlta's target to reduce 75 per cent of our scope 1 and 2 GHG emissions by 2026 from a 2015 base year is estimated to align with the electricity sector decarbonization pathway to limit global warming to 1.5°C, as one of the Paris Agreement goals.

In December 2021, the Company committed to setting a science-based emissions reduction target through the Science Based Target initiative ("SBTi"). In 2022, we started the target validation process of our 2026 scope 1 and 2 emissions reduction target. In 2023, TransAlta did not anticipate that setting a near-term scope 3 target would be a condition to our scope 1 and 2 target being validated by the SBTi. This would mean accelerating the validation of our scope 3 emissions ahead of the Company's intended timelines. As a result, given SBTi's requirement that we establish a near-term scope 3 reduction target, we determined to withdraw from our commitment to the SBTi. TransAlta remains confident that our significant scope 1 and 2 emissions reduction trajectory from 2015 to 2026 is in line with the electricity sector pathway to limit global warming to 1.5°C.

GHG Disclosures

Scope 1 and 2 Emissions

Our scope 1 and 2 GHG emissions are calculated using a number of different methodologies depending on the technologies available at our facilities. Emissions data has been aligned with the "Setting Organizational Boundaries: Operational Control" methodology set out in the GHG Protocol: A Corporate Accounting and Reporting Standard developed by the World Resources Institute and the World Business Council for Sustainable Development. We report emissions on an operation control basis, which means we report 100 per cent of emissions at the facilities that we operate.

The GHG Protocol classifies a company's scope 1 emissions as the direct emissions from owned or controlled sources. Scope 2 emissions are indirect emissions from the generation of purchased energy.

We compile our corporate GHG inventory using our business segment GHG calculations. As a result, emission factors and global warming potentials used in our GHG calculations can vary due to difference in regional compliance guidance. Applying harmonized global warming potentials across our fleet would result in a minor variance to our overall calculated GHG totals.

Our 2023 GHG data was reported to a number of different regulatory bodies throughout the year for regional compliance and, as a result, may incur minor revisions as we review and report data. Any historical revisions will be captured and reported in future disclosure. As per the

Kyoto Protocol, GHGs include carbon dioxide, methane, nitrous oxide, sulphur hexafluoride, nitrogen trifluoride, hydrofluorocarbons and perfluorocarbons. Our exposure is limited to carbon dioxide, methane, nitrous oxide and a small amount of sulphur hexafluoride. The majority of our estimated GHG emissions result from carbon dioxide emissions from stationary combustion from coal and natural-gas-powered generation. Methane emissions from our operations are mainly due to incomplete combustion of natural gas from the natural-gas-powered plants and there are no fugitive methane emissions associated with our operations. In 2023, methane emissions were 0.2 per cent of our total emissions.

The following tables detail our GHG emissions by scope, business segment and country in million tonnes of CO_2e. Some values do not sum to the indicated total due to rounding of tabulated emissions. Zeros (0.0) indicate truncated values.

Year ended Dec. 31	2023	2022	2021
Scope 1	**10.9**	10.2	12.4
Scope 2	**0.0**	0.1	0.1
Total scope 1 and 2 GHG emissions	**10.9**	10.2	12.5

Year ended Dec. 31	2023	2022	2021
Hydro	**0.0**	0.0	0.0
Wind and Solar	**0.0**	0.0	0.0
Gas	**6.4**	6.3	6.5
Energy Transition	**4.5**	4.0	6.0
Corporate and Energy Marketing	**0.0**	0.0	0.0
Total scope 1 and 2 GHG emissions	**10.9**	10.2	12.5

Year ended Dec. 31	2023	2022	2021
Australia	**1.0**	0.9	1.0
Canada	**5.3**	5.2	7.9
US	**4.6**	4.1	3.6
Total scope 1 and 2 GHG emissions	**10.9**	10.2	12.5

In 2023, our GHG emissions (scopes 1 and 2) were 10.9 million tonnes as a result of normal operating activities. Despite the increase in absolute emissions as a result of increased production, our scope 1 and 2 GHG emissions intensity remains similar to the previous year at 0.41 tCO2e/MWh (2022 - 0.40 tCO2e/MWh). TransAlta will cease generation from our single remaining US coal unit by the end of 2025, which will further reduce the Company's emissions.

TransAlta sells the environmental attributes generated from our renewable energy facilities and does not subtract this amount from our total GHG emissions (scope 1 and 2). However, it should be noted that TransAlta's customers are reporting GHG emissions reductions using our renewable energy assets, projects and operations.

GHG emissions are verified to a level of reasonable assurance in locations in which we operate within a carbon regulatory framework. Any historical revisions to GHG data will be captured and reported in future disclosure. The majority of our GHG emissions result from carbon dioxide emissions from stationary combustion from coal and natural-gas-powered generation.

The following table highlights our scope 1 and 2 GHG emissions reductions since 2015 and our targeted emissions in 2026. The actual GHG emissions for the Company in 2026 will vary from that presented below depending on, among other things, the growth of the Company, including its on-site generation business.

Year ended Dec. 31	2026 (forecast)	2023	2015
Total scope 1 and 2 GHG emissions (million tonnes CO_2e)	**8.1**	10.9	32.2

Scope 3 Emissions

Scope 3 emissions are all indirect emissions (not included in scope 1 or 2) that occur in the value chain of the reporting company, including both upstream and downstream emissions. TransAlta's scope 3 emissions are calculated using methodologies consistent with the GHG Protocol Corporate Value Chain (Scope 3) Accounting and Reporting Standard ("Scope 3 Standard") and with reference to the additional guidance provided in the GHG Protocol Technical Guidance for Calculating Scope 3 Emissions ("Scope 3 Guidance") developed by the World Resources Institute and the World Business Council for Sustainable Development.

Our scope 3 emissions include the indirect GHG emissions resulting from activities in our value chain but outside of our operational control. We estimate our scope 3 emissions in 2023 to be approximately four million tonnes of CO_2e, which is primarily attributed to our non-operated joint venture interests as part of Category 15: Investments. Of the 15 categories described in the GHG Protocol Scope 3 Guidance, four are not relevant to our business and, therefore, are not included in the calculation: Category 8: Upstream leased assets, Category 12: End-of-life treatment of sold products, Category 13: Downstream leased assets, and Category 14: Franchises.

Since 2022, we have focused on enhancing our scope 3 emissions accounting. In 2022, we engaged with an independent third-party consulting company to complete a methodology review of our scope 3 inventory based on the GHG Protocol Scope 3 Guidance. In 2023, we engaged with an independent third-party advisory firm to complete a pre-assessment of material scope 3 emissions so that we can meet our target to verify and disclose 80 per cent of TransAlta's scope 3 emissions by 2024, with the aim of reporting on 2023 scope 3 emissions as part of our 2024 Integrated Report.

Avoided Emissions

In 2023, production from renewable assets resulted in the avoidance of approximately 2.3 million tonnes of CO_2e for our customers. TransAlta's avoided emissions are defined as the sum of the displaced emissions by our renewable assets in the jurisdictions where we operate. The value is calculated as the product of the generation of electricity obtained from a renewable source (hydro, wind and solar) and the specific CO_2 emissions intensity from the grid of the jurisdiction in which we operate. Avoided emissions decreased in 2023 compared to 2022 primarily due to the reduction of emission intensity of the grid. As the world decarbonizes over time, the emission intensity of the grid will gradually decrease year over year. The following table highlights our avoided emissions in the reporting year.

Year ended Dec. 31	2023	2022	2021
Total GHG emissions avoided (million tonnes CO_2e)	**2.3**	2.7	2.6

Sustainable Finance

Sustainable finance is the process of taking due account of ESG considerations (e.g., climate change, biodiversity, human rights, etc.) when making investment decisions. Sustainable finance is a key pillar of TransAlta's Climate Transition Plan. This means we will utilize pools of capital available to sustainable economic activities and projects to finance our energy transition towards net-zero operations.

TransAlta deploys green and sustainable financing to build our renewable energy fleet and advance our clean energy transition. This supports our goal to deliver on our customers' needs for clean electricity. Since 2020, we have issued $684 million in green bonds and converted our four-year $2.0 billion revolving credit facility into a sustainability-linked loan.

In 2022, TransAlta issued US$400 million ($533 million) in Senior Green Bonds, an amount equal to the net proceeds from the bonds has been allocated to finance or refinance new and/or existing eligible green projects. The bonds were issued under TransAlta's Green Bond Framework, which aligns with the Green Bond Principles published by the International Capital Market Association. For further information, refer to Green Bond Framework in the Shareholder Information section of the Investor Centre on our website. In 2021, the Company's indirect wholly owned subsidiary, Windrise Wind LP, completed a secured green bond offering by way of private placement for approximately $170 million (face value).

In 2021, TransAlta converted an existing $1.3 billion syndicated revolving credit facility into a sustainability-linked loan. The loan aligns the cost of borrowing to the Company's GHG emissions reductions and gender diversity targets. Sustainability-linked loans are any types of loan instruments and/or contingent facilities (such as bonding lines, guarantee lines or letters of credit) that incentivize the borrower's achievement of ambitious, predetermined sustainability performance objectives.

The summary below shows the carrying value of the issued green bonds and the total facility size of our ESG financial operations portfolio.

As at Dec. 31 (in millions of Canadian dollars)	2023	2022	2021
Green bonds [(1)]	**684**	703	171
Sustainability-linked loans	**1,950**	1,250	1,250

(1) Green bonds are related to Senior Green Bonds issued in 2022 and the Windrise Wind green bond issued in 2021.

Climate-Related Financial Metrics

The results of TransAlta's 2021 climate-related scenario analysis, aligning with a 1.5°C warmer world, have shown that opportunities to grow the renewable fleet exist across all scenarios and locations. Our adjusted revenue from renewable energy generation (hydro, wind and solar) in 2023 was $902 million (2022 – 1,014 million) or 27 per cent of our total adjusted revenue in 2023.

We continue to execute the Clean Electricity Growth Plan updated in 2023 to deliver up to 1.75 GW of incremental renewables capacity and a 10 GW growth pipeline by 2028. In 2023, our growth capital expenditures for renewable energy generation was $630 million (2022 – $666 million). In addition, TransAlta continues to invest in emerging abatement technologies and solutions. In 2023, our investments in low-carbon research and development were $4 million (2022 – $12 million).

As part of our Clean Electricity Growth Plan, our goal is to achieve 70 per cent of adjusted EBITDA from renewables and storage by the end of 2028. In 2023, adjusted EBITDA from renewable energy generation was $716 million (2022 – $838 million) or 44 per cent of our total adjusted EBITDA. Our renewable fleet makes our overall portfolio more resilient to climate-related risks, provides increased flexibility in generation and creates incremental environmental value through environmental attributes. Our revenue in 2023 from environmental attribute sales was $36 million (2022 – $53 million).

The disclosure of TransAlta's financial metrics related to our climate-related risks and opportunities align with the IFRS S2 and TCFD recommendations. A summary of our climate-related financial metrics is presented below.

Year ended Dec. 31 (in millions of Canadian dollars)	2023	2022	2021
Growth capital expenditures for renewable energy generation[(1)]	**630**	666	326
Renewable energy adjusted EBITDA[(2)]	**716**	838	584
Environmental attribute sales revenue[(3)]	**36**	53	40
Renewable energy adjusted revenue[(4)]	**902**	1,014	731
Investments in low-carbon research and development[(5)]	**4**	12	—

(1) Growth capital expenditures include amounts deployed for growth projects and acquisitions related to renewable energy generation. This includes the construction of our Windrise wind facility completed in 2021, the acquisition of North Carolina Solar portfolio in 2021, the construction of the Garden Plain wind project, White Rock wind projects, Horizon Hill wind project and Northern Goldfields solar project as part of our Clean Electricity Growth Plan. This excludes the Mount Keith transmission expansion project.

(2) Adjusted EBITDA from renewable energy generation includes hydro, wind, solar and battery storage facilities. The renewable energy adjusted EBITDA is the total adjusted EBITDA of the Hydro and Wind and Solar segments. These items are not defined and have no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures and Segmented Financial Performance and Operating Results sections of this MD&A.

(3) Environmental attribute sales revenue indicates the full amount of hydro, wind and solar environmental credits, without any other consolidation impacts.

(4) Adjusted revenue from renewable energy generation includes hydro, wind, solar and battery storage facilities. For details of the adjustments to revenues included in adjusted EBITDA refer to the Additional IFRS and Non-IFRS Measures section of this MD&A

(5) Investments in low-carbon research and development include our equity investment in Ekona Power Inc.'s ("Ekona") Series A funding round and our four-year investment in EIP's Deep Decarbonization Frontier Fund 1 (the "Frontier Fund").

Alignment with Climate-Related Disclosures Frameworks

The table below shows the alignment of our climate change management disclosure with TCFD, IFRS S2 and CDP (2023) recommendations.

TCFD Recommended Disclosures	Other Alignments	Location
Governance		
Describe the board's oversight of climate-related risks and opportunities	IFRS S2: 6; CDP: C1.1	Oversight by the Board of Directors
Describe management's role in assessing and managing climate-related risks and opportunities	IFRS S2: 6; CDP: C1.2	Role of Senior Management
Strategy		
Describe the climate-related risks and opportunities the organization has identified over the short, medium and long term	IFRS S2: 8-9; CDP: C2.1	Key Scenario Findings
Describe the impact of climate-related risks and opportunities on the organization's businesses, strategy and financial planning	IFRS S2: 8-9; CDP: C2.3, C2.4, C3.3, C3.4	Climate Change Strategy, Key Climate Scenario Findings
Describe the resilience of the organization's strategy, taking into consideration different climate-related scenarios, including a 2°C or lower scenario	IFRS S2: 22-23; CDP: C3.1, C3.2	Climate Scenarios, Key Climate Scenario Findings
Risk management		
Describe the organization's processes for identifying and assessing climate-related risks	IFRS S2: 10; CDP: C2.2	Climate Change Strategy
Describe the organization's processes for managing climate-related risks	IFRS S2: 24-25; CDP: C2.2	Managing Climate Change Risks and Opportunities
Describe how processes for identifying, assessing and managing climate-related risks are integrated into the organization's overall risk management	IFRS S2: 24-25; CDP: C2.2	Managing Climate Change Risks and Opportunities
Metrics and targets		
Disclose the metrics used by the organization to assess climate-related risks and opportunities in line with its strategy and risk management process	IFRS S2: 27-28; CDP: C6.1, C6.3, C6.5, C9.1	Climate Change Metrics and Targets
Disclose scope 1, scope 2 and, if appropriate, scope 3 greenhouse gas (GHG) emissions and the related risks	IFRS S2: 29-32; CDP: C6.1, C6.3, C6.5	Climate Change Metrics and Targets
Describe the targets used by the organization to manage climate-related risks and opportunities and performance against targets	IFRS S2: 33-36; CDP: C4.1, C4.2	Climate Change Metrics and Targets

Enabling Innovation and Technology Adoption

Technology and innovation are an existing and increasing focus at TransAlta. We have long been innovators. TransAlta has been at the forefront of innovation in the power-generation sector since the early 1900s when we developed hydro assets. We have been an early adopter and developer of wind technology in Canada, including the first commercial wind farm in Canada, and are now one of the largest wind generators in the country. In 2015, we made our first investment in solar technology in Massachusetts, in 2020, we installed the first utility-scale battery in Alberta and, in 2023 we completed our first solar microgrid with battery energy storage system in Western Australia. We are now looking to advance a new technology roadmap that aligns with the Clean Electricity Growth Plan. This section covers manufactured and intellectual capital management as per guidance from the International Integrated Reporting Framework.

Our Energy Innovation Team

As part of our Clean Electricity Growth Plan, in 2021, we established an Energy Innovation team to investigate, prioritize and deploy new net-zero electricity generation technologies that address the three main factors of our energy transition: reliability, decarbonization and affordability. As we grow our renewables business, the Energy Innovation team is focused on what we should build next that complements our hydro, wind and solar assets to deliver reliable, affordable and low-carbon electricity to our customers. At the same time, the Energy Innovation team is looking at electrification broadly to investigate where potential new, adjacent business opportunities may exist for TransAlta.

Our Energy Innovation team participates in the Energy Futures Lab, a multi-stakeholder initiative that brings together innovators, influencers, and experts from different sectors and perspectives to address the challenges and opportunities of achieving a net-zero Alberta energy system. In 2023, TransAlta sponsored the Energy Futures Labs Alberta's Electricity Futures Working Group, which aims to foster collaboration to explore and test new solutions for a reliable, affordable, and low-carbon electricity system in Alberta. We also continue to participate in the energy innovation ecosystem through engagement with various innovation accelerators that 'incubate' and accelerate start-ups by matching new technology solutions with practical problems identified by end-users, like TransAlta.

In 2023, TransAlta launched its Energy Innovation Series. The Series is led by our Energy Innovation Team along with guest speakers from across the Company and aims to empower our workforce through relevant industry knowledge on innovation in the electricity sector. In 2023, we delivered four sessions on a range of relevant topics including grid reliability during the energy transition, grid energy storage options and decarbonized baseload generation strategies.

For further details on how we invest in our workforce, please refer to Talent and Employee Development in the Building a Diverse and Inclusive Workforce section of this MD&A.

Renewable Energy

In 2023, TransAlta's nameplate capacity was 944 MW from hydro energy, 2,046 MW from wind and battery storage, and 181 MW from solar power. We continue to look for opportunities to develop and operate solar energy.

In August 2023, the Garden Plain wind facility in Alberta was commissioned adding 130 MW to our gross installed capacity. The facility is fully contracted with Pembina Pipeline Corporation (100 MW) and PepsiCo Canada (30 MW), with a weighted average contract life of approximately 17 years.

In November 2023, the 48 MW Northern Goldfields solar and battery storage facilities in Western Australia achieved commercial operation. The facilities consist of the 27 MW Mount Keith solar facility, 11 MW Leinster solar farm and 10 MW/5 MWh Leinster battery energy storage system and interconnecting transmission infrastructure, all of which are now integrated into TransAlta's 169 MW Southern Cross Energy North remote network. The Northern Goldfields solar facilities are expected to reduce BHP Nickel West's scope 2 electricity GHG emissions from its Leinster and Mount Keith operations by 12 per cent and is long-term contracted with a globally recognized counterparty for 16 years.

In 2023, the Company continued to advance the 300 MW White Rock wind projects, to be located in Oklahoma. The White Rock wind projects are expected to achieve commercial operation in the first quarter of 2024. In 2021, we entered into two long-term PPAs with Amazon for the offtake of 100 per cent of the generation from these projects.

In 2023, TransAlta advanced the construction of its 200 MW Horizon Hill wind project located in Oklahoma, with a target commercial operation date in the first quarter of 2024. In 2022, the Company executed a long-term renewable energy PPA with a subsidiary of Meta for 100 per cent of the generation from the project. Under this agreement, Meta will receive both renewable electricity and environmental attributes from the Horizon Hill wind project.

TransAlta is actively advancing its development pipeline for renewable energy generation. In 2023, the Company established a pipeline of potential growth projects in renewables that includes 280 MW of advanced-stage development projects along with 4,285 to 5,015 MW of projects in earlier stages of development.

Scaling Up Energy Solutions

Battery Storage

We continue to invest in battery energy storage systems and see them as an important element for TransAlta to continue to provide reliability through the energy transition – continuing an important role TransAlta has played for over one hundred years with our hydro units.

In November 2023, the Northern Goldfields solar and battery storage facilities in Western Australia achieved commercial operation and are now supplying reliable electricity to BHP's remote nickel mining operations in Western Australia. The energy storage consists of the 10 MW/5 MWh Leinster Battery Energy Storage System which will be integrated into TransAlta's remote network. The network and new generation will support BHP Nickel West to meet its emissions reduction targets and deliver lower-carbon nickel to its customers. TransAlta is continuing to work with BHP Nickel West on the development of other projects to further reduce scope 2 GHG emissions at BHP's Mt Keith and Leinster operations.

In 2023, TransAlta's development pipeline included four energy storage projects in Canada: WaterCharger (lithium-ion battery storage, 180 MW), Tent Mountain (pumped hydro storage, 160 MW), Brazeau (pumped hydro storage, 300-900 MW) and New Brunswick Power Battery (battery, 10 MW). These strategically-located units could play various roles on electricity grids including providing reliability services and storing surplus generation for discharge at peak periods.

Electric Mobility

Companies can play an important role in driving the transition to electric vehicles by taking the lead in their own operations. Recognizing this role, TransAlta is exploring the potential of electrifying our service fleet with zero-emission vehicles. In 2023, we launched a pilot project called Project Electrify to test four fully-electric vehicles at different facilities in Canada. We will assess their performance, safety and cost-effectiveness under different conditions and operator needs. The project will run from 2024 to 2025, during which time our operators will gain hands-on experience with the technology and provide feedback on its suitability for wider adoption. Based on the learnings from the project, TransAlta will decide whether to pursue further electrification of our fleet.

Future Solutions

Hydrogen

In 2022, we announced a $2 million equity investment in Ekona's Series A funding round. The investment will help support the commercialization of Ekona's novel methane pyrolysis technology platform, which produces cleaner and lower-cost turquoise hydrogen. If successful, Ekona's distributed technology allows for onsite production of hydrogen, hence avoiding the need for costly transportation of hydrogen. Furthermore, its solid carbon byproduct allows for low-cost, low-emissions hydrogen production without the need for carbon sequestration. TransAlta is a member of Ekona's Strategic Committee and continues to work with Ekona as it develops its pyrolysis technology.

Small Modular Reactors ("SMR")

Small modular reactors have a power capacity of up to 300 MW per unit and differ from traditional nuclear in that they are built to be modular, factory-assembled units that are transported to a location for installation. Additionally, they implement passive or walk-away safety features designed to dramatically reduce the risk of nuclear events. While high costs remain a challenge for all forms of nuclear, SMR developers argue that smaller MW plants made from manufactured components will allow the industry to access steep cost declines as the technology matures and more units are deployed. By providing reliable, emissions-free baseload power, nuclear power may play an important role in clean energy transitions. Today, nuclear power makes a significant contribution to low-carbon electricity generation and has significant potential to contribute to power sector decarbonization. TransAlta continues to monitor developments in SMR.

Nature-based Solutions ("NBS")

Nature-based solutions are actions to protect, sustainably manage and restore natural and modified ecosystems that address societal challenges effectively and adaptively, simultaneously benefiting people and nature. TransAlta is actively evaluating NBS as carbon removals to neutralize any residual emissions that we cannot yet eliminate.

Direct Air Capture ("DAC")

Direct air capture technologies extract CO_2 directly from the atmosphere. The CO_2 can be permanently stored in deep geological formations, thereby achieving permanent CO_2 removal. TransAlta continues to explore the benefits of DAC as a carbon dioxide removal option to support the net-zero transition of our operations and customers.

Carbon Capture, Utilization and Storage ("CCUS")

Our teams continuously explore the use of applied or new technologies such as CCUS to reduce GHG emissions. We know that new technologies will emerge over the next number of years as the industry continues to drive towards lower emissions while maintaining a reliable and affordable product for customers.

Disruptive Technologies

In 2022, we entered into a commitment to invest US$25 million over the next four years in Energy Impact Partners' ("EIP") Deep Decarbonization Frontier Fund 1 (the "Frontier Fund") that invests in early-stage, innovative technology companies that will accelerate the transition to net-zero GHG emissions. TransAlta's investment in the Frontier Fund provides TransAlta with the opportunity to pool funds with some of the largest utilities in the United States and Europe to identify, pilot, commercialize and bring to market technologies that will support its decarbonization goals.

Fusion

Fusion technologies attempt to recreate the fusion reactions in the sun by fusing two hydrogen molecules together. If successful, fusion promises low-cost energy, with far shorter-lived nuclear waste. Fusion achieved some significant development milestones in 2022, including most significantly, Lawrence Livermore National Laboratory achieving net energy gain. This, coupled with unprecedented capital flow into fusion companies, has led to newfound excitement that fusion may be able to leapfrog current generation technologies.

Through EIP, TransAlta has invested in ZAP Energy, a leading fusion start-up. ZAP Energy's technology stabilizes the hydrogen plasma using sheared flow (driving current through the flow creating the magnetic field confining and compressing the plasma) rather than magnetic fields. In 2022, ZAP announced it will conduct a feasibility study of retrofitting the former TransAlta Big Hanaford gas plant located in Centralia to host its first-of-a-kind Z-pinch fusion pilot plant. ZAP received $1 million from the Centralia Coal Transition Grants Energy Technology Board as part of our energy transition investments to move away from coal in Washington State.

For more information on investments in low-carbon research and development, refer to Climate-Related Financial Metrics section of this MD&A.

Analytics and Automation

Asset Performance

TransAlta's Asset Performance team was founded in 2023 to continue the work initiated by our previous Asset Analytics and Optimization team founded in 2008. This team monitors the Company's generation portfolio across Canada, the US and Australia. A centralized team of engineers and operations specialists remotely monitors our power facilities for emerging equipment reliability and performance issues. The Asset Performance team also performs production reporting functions for these assets and is actively engaged in projects to improve this reporting.

The Data and Innovation team worked with partners across the company to advance its Asset Performance Management platform, GenOS, to deliver new features that increase the performance and management of our renewable asset fleet. Key process improvements, such as enhanced performance analytics that leverage machine learning, advanced analytics and data science models, provide our operators with deeper insights to help optimize asset performance across the entire fleet. Built in-house, GenOS provides data-driven insights for our wind, solar, gas and hydro fleets

Asset Performance staff are trained in the development and use of specialized equipment monitoring and performance assessment software and they apply their experience to power facility operations. If an issue is detected, the Asset Performance engineer will initially assess and then notify facility operations of their findings to support investigation and remedy of the issue before there is an impact to operations. This support is critical for reliability and performance of our operations. For example, if a wind turbine starts to show very early signs of equipment change compared to others, our operation team is notified and will work to investigate and remedy the issue. The monitoring, analysis and diagnostics completed by the Asset Performance engineer are focused on early identification of equipment issues based on longer-term trend analysis and complements day-to-day facility operations.

Automation and Robotics

TransAlta created the Data and Innovation team in 2019 to modernize its data infrastructure and take advantage of new opportunities in analytics and data science. The Data and Innovation team is cross-functional; composed of data architects, data engineers, data analysts, software developers, integration specialists and engineers. The team focuses on the delivery of value using digital innovation, such as the modernization of data management strategy and platforms, the rapid delivery of data-driven applications, the design and implementation of advanced analytics and machine learning models and the execution of robotic process automation to eliminate manual tasks.

The substantial growth of our Advanced Automation Program has increased the number of manual processes we have automated, allowing our subject matter experts to spend more time on higher-value opportunities. With industry leaders in automation, TransAlta is able to leverage high impact technology to quickly develop custom robotic process automations across the company.

Drones

In 2022, TransAlta formed the Robotics Inspection Council. The Council's purpose is to coordinate and assess the use of drones for robotic inspections to increase value to the business through improved safety, reduced inspection costs and better communication. In alignment with TransAlta's core value of safety, the Council defined the corporate requirements on the safe use of remotely piloted aircraft in TransAlta's fleet. In 2023, drone technology was used in TransAlta's gas and hydro fleets to inspect boiler internal components, canals and cooling ponds, and a "drone in a box" solution was trialed and purchased for improved site security. The Council continues to meet with vendors and industry peers to understand areas of opportunity and how these technologies are being deployed. Robotic inspections were performed in TransAlta's gas and hydro fleets. The Council is investigating additional applications in our fleet for 2024.

Engaging with Our Stakeholders to Create Positive Relationships

We strive to create shared value for our stakeholders through social and relationship value creation at TransAlta. The most material impacts on our social and relationship performance are fostering positive relationships with Indigenous neighbours, communities, stakeholders, governments, industry and landowners in the areas where we operate, as well as public health and safety. This section covers sustainability factors of social and relationship capital and intellectual capital as per guidance from the International Integrated Reporting Framework.

Inclusive Transition

In support of our energy transition, since 2015, TransAlta has been investing US$55 million over 10 years to support energy efficiency, economic and community development and education and retraining initiatives in Washington State. The investment is part of the TransAlta Energy Transition Bill passed in 2011. This bill was a historic agreement between policymakers, environmentalists, labour leaders and TransAlta to transition away from coal in Washington State by closing the Centralia facility's two units, one in 2020 and the other in 2025. Three funding boards were formed to invest the US$55 million: the Weatherization Board (US$10 million), the Economic and Community Development Board (US$20 million), and the Energy Technology Board (US$25 million). To date, the Weatherization Board has invested US$9.5 million, the Economic and Community Development Board US$15 million and the Energy Technology Board US$15 million.

Specific projects that the boards funded in 2023 include: the replacement of a diesel bus with a new electric bus by the Skamania School District; the installation of a 100 kW roof mounted solar system at Palouse High School by the Palouse School District; the installation of a 100kW ground mounted solar system at the Wastewater Treatment Plant owned by the City of Medical Lake; and pre-employment training services for youth in Lewis County by Morningside Services.

Additionally, in 2016, TransAlta announced that we had reached an agreement with the Government of Alberta for the cessation of emissions from coal-fired electricity generation facilities in Alberta (Off-Coal Agreement). As part of the Off-Coal Agreement, TransAlta has invested in programs and initiatives to support the communities surrounding the plants negatively impacted by the phase-out of coal generation during the transition.

Customers

TransAlta serves industrial and commercial customers with power and energy services across its fleet in Canada, the US and Australia. We are focused on customer-centred renewables growth to bring high levels of service quality and reliability for our customers in a low-carbon future. As one of the largest electricity generators in Canada, our team serves businesses with:

- Energy solutions starting from the design phase;
- Energy consumption and cost management solutions;
- Market price risk and volume exposure mitigation; and
- Monitoring of energy market design changes, price signals and applicable and available incentives.

The Customer Solutions team at TransAlta has maintained a large portfolio of customers in Alberta across a broad range of industry segments, including commercial real estate, municipal, manufacturing, industrial, hospitality, finance and oil and gas. Our work has been recognized by our customers through an average retention rate of 89 per cent over the last three years.

Across our business in Canada, the US and Australia, we provide on-site generation for large mining and industrial customers. This requires us to continually engage with these customers, ensuring that current electricity requirements are provided safely, reliably and cost-effectively with the benefit of lower GHG emissions. We continue to explore opportunities to provide 24/7 carbon-free energy to help customers meet their decarbonization goals.

We continue to develop renewable energy facilities to support customers achieving their sustainability goals and targets, such as 100 per cent renewable power targets and/or GHG emissions reduction targets. Production from renewable electricity in 2023 resulted in the avoidance of approximately 2.3 million tonnes of CO_2e for our customers.

Our experience in developing and operating power facilities is highlighted below:

Power generation type	Operating experience (years)
Hydro	112
Natural Gas	73
Wind	26
Solar	9
Battery Energy Storage Systems	3

For further details on how we support our customers' sustainability objectives, please refer to the Enabling Innovation and Technology Adoption section of this MD&A.

Human Rights

TransAlta is committed to honouring domestic and internationally accepted labour standards and supports the protection of human rights of all its employees, contractors, suppliers, partners, Indigenous partners and other stakeholders. We abide by human rights and modern slavery legislation in Canada, the US and Australia. We have a zero tolerance approach to discrimination based on age, disability, gender, race, religion, colour, national origin, political affiliation or veteran's status or any other prohibited ground as defined by human rights legislation in the jurisdictions in which we operate. We afford equal opportunities for all gender identities, support the right to freedom of association and the right to organize unions and bargain collectively. We do not conduct operational human rights reviews or impact assessments, but we have governance practices in place for the protection of human rights.

Our Human Rights and Discrimination Policy outlines our commitment to human rights in our operations and supply chain to ensure that our personnel policies and practices in our global operations respect fundamental rights. Expected behaviours of all our employees are set out in our Corporate Code of Conduct. We are committed to creating a work environment where all workers feel safe and are valued for the diversity they bring to our business. Our annual mandatory Code of Conduct training is required for employees prior to signing off the Code of Conduct. In 2023, 100 per cent of employees completed the training and acknowledged and signed the Code of Conduct. We also have adopted a Supplier Code of Conduct that defines the principles and standards expected of suppliers, their employees and contractors to meet while providing goods and/or services to TransAlta.

Our Whistleblower Policy provides a mechanism for our employees, officers, directors and contractors to report, among other things, any actual or suspected ethical or legal violations. We would seek to remedy the impact promptly in order to establish a corrective action plan in collaboration with the relevant individuals and stakeholders.

In Australia, since 2020, we have reported under federal modern slavery legislation. Our *Modern Slavery Act* Statements demonstrate the actions we have taken to assess and address modern slavery risks within our operations and supply chain. These annual statements are approved by our Board of Directors and are publicly available. In 2024, we will report under Canada's *Fighting Against Forced Labour and Child Labour in Supply Chains Act*.

Supply Chain and Sustainable Sourcing

We continue to seek solutions to advance supply chain sustainability. As we explore major projects, we assess vendors both at the evaluation stage and as part of information requests on such elements as safe work practices, environmental practices and Indigenous spend. This means, for example and for select procurement engagements, getting information on:

- Estimated value of services that will be procured though local Indigenous businesses;
- Estimated number of local Indigenous persons that will be employed;
- Understanding overall community spend and engagement; and
- Understanding the state of community relations through interview processes and stakeholder work.

Supply chain is a pillar of our Clean Electricity Growth Plan to deliver net-zero operations. We have enhanced the supplier management functionality within our corporate procurement system and are working to incorporate ESG data reporting capability. In the next few years, we will develop ESG criteria for supply chain engagement and work to understand our direct suppliers' GHG emissions profile and targets. Our long-term plan is to engage with suppliers to explore enhancement of their GHG emissions targets and set direction for engaging suppliers with GHG emissions reduction targets.

In 2022, TransAlta approved a new goal to integrate sustainability into supply chain. Our target is "By 2024, 80 per cent of our spend will be with suppliers that have a sustainability policy or commitment". This supports the intent of the UN SDG Target 12.7: "Promote public procurement practices that are sustainable, in accordance with national policies and priorities." In 2023, we confirmed that on average 78 per cent of our spend in 2022 and 2023 was with suppliers that have a sustainability policy or commitment. TransAlta will continue to consider other targets to help integrate sustainability into supply chain.

Our Supplier Code of Conduct applies to all vendors and suppliers of TransAlta. Under this code, suppliers of goods and services to TransAlta are required to adhere to our core values, including health and safety, ethical business conduct and environmental leadership. The code also allows suppliers to report ethical or legal concerns via TransAlta's Ethics Helpline.

Indigenous Relationships and Partnerships

At TransAlta, we value relationships and partnerships with our Indigenous neighbours, aspiring to the highest standards in our relationships with Indigenous peoples. Our core values of safety, innovation, sustainability, respect and integrity represent how we do business and engage with Indigenous peoples. Our commitment to Indigenous relations is led by a centralized corporate team who foster a relationship-based approach, involving employees at our facilities and within each business unit. These employees and teams build relationships with the neighbouring Indigenous communities and work to develop respectful, trusting relationships that help TransAlta continually improve its business practices.

Our Indigenous Relations Policy focuses on five key areas: community engagement and consultation, business development, community investment, employment, and training and awareness. We ensure that TransAlta's principles for engagement are upheld and the Company fulfils its commitments to Indigenous communities. Efforts are focused on building and maintaining solid relationships and strong communication channels that enable TransAlta to: share information regarding operations and growth initiatives; gather feedback to inform project planning; and understand priorities and interests from communities to better address concerns and unlock opportunities.

Methods of engagement include:

- Relationship building through regular communication and meetings with representatives at various levels within Indigenous communities and organizations;
- Hosting company-community activities to share both business information and cultural knowledge;
- Maintaining consistent communications with each community and following appropriate community protocols and procedures;
- Participating in community events such as pow wows and blessing ceremonies; and
- Providing both monetary and in-kind sponsorships for community initiatives.

TransAlta takes a proactive approach in engagement by initiating communication early in project development to allow concerns to be identified and addressed, which has minimized potential project delays. We strive to maintain relationships through the life cycle of our facilities, from project development and construction, through operation, until decommissioning phases are complete. We work with communities to build relationships based on a foundation of ongoing communication and mutual respect. This is recognized in our Indigenous Relations Policy, which was recently updated to include our acknowledgement and understanding of the intent of the recommendations of the United Nations Declaration on the Rights of Indigenous Peoples.

In 2024, TransAlta will continue to ensure that all new employees complete Indigenous cultural awareness training as part of the Company's onboarding process.

Support for Indigenous Youth, Education and Employment

TransAlta recognizes the importance of investing in Indigenous students and our financial support helps students complete their education, become self-sufficient and move forward to become future leaders in their communities. We are keen to help young Indigenous students reach their full potential and achieve their dreams. We also believe in providing support to Indigenous primary school students, helping to instill a passion for lifelong learning.

In 2023, TransAlta provided more than $453,000 to support Indigenous youth, education and employment programs, representing 14 per cent of TransAlta's total community investment. Highlights include:

- Mother Earth's Children's Charter School ("MECCS") – Located in Treaty 6 territory, Alberta, MECCS offers education for students from kindergarten to Grade 9 and is cited as Canada's first and only Indigenous children's charter school. The student population is diverse and includes Métis, Cree, Nakoda Sioux and Stoney. MECCS is a tuition-free public school integrating Indigenous culture, beliefs and perspectives into elementary school experience. The school specializes in working with children suffering from adversity and provides enhanced learning support. MECCS students have a high success rate for completing high school and winning academic awards. In 2023, TransAlta provided $35,000 to support the school's operations plus a holiday donation to enable a student celebration.

- The Read On Literacy Program ("Read On") – In 2023, TransAlta partnered with Read On to provide elementary students in communities near our operations with in-person and virtual sessions. Read On is an Indigenous literacy program that seeks to mentor young people in First Nation schools to achieve their maximum academic, personal and social development by promoting the core values of education, literacy, taking pride in ones' culture and making good decisions in one's life.
- Diamond Willow Youth Lodge – In partnership with the United Way of Calgary and Area, designated funding was provided to the Diamond Willow Youth Lodge, which is a safe place for Calgary Indigenous youth to connect with peers and participate in a variety of programs that promote health and wellness, education and employment preparation.
- Wihnemne School Hot Lunch Program – In 2023, TransAlta partnered with the community school at Paul First Nation in Alberta on a program designed to ensure the Nation's children receive nutritious meals each day maximizing their scholastic success. This program is cited as a catalyst responsible for strong growth in the school's enrollment.

Indigenous Cultural Awareness Training for TransAlta Employees

In November 2023, TransAlta successfully reached 100 per cent completion of the Indigenous Cultural Awareness Training program across our operating jurisdictions in Canada, the US and Australia. In line with our sustainability target set in 2021, the Company made a deliberate effort to ensure that every employee participated in Indigenous Cultural Awareness training over the past two years. This initiative has been instrumental in providing valuable insights into the rich history, culture and perspectives of Indigenous communities within the jurisdictions where we operate.

Stakeholder Relationships

Fostering positive relationships with our stakeholders is important to TransAlta. Driven by our core values, we see stakeholder transparency as an integral part of our relationships. We take a proactive approach to building relationships and understanding the impacts our business and operations may have on local stakeholders.

Our Stakeholders

To act in the best interests of the Company and optimize the balance between financial, environmental and social values of our stakeholders and TransAlta, we seek to:

- Build relationships through regular engagement with stakeholders regarding our operations, growth prospects and future developments;
- Consider feedback and make changes to project designs and plans to resolve and/or accommodate concerns expressed by our stakeholders; and
- Respond in a timely and professional manner to stakeholder inquiries and concerns and work diligently to resolve issues or complaints.

Our stakeholders are identified through stakeholder mapping exercises and prospective project development or acquisition. Through decades of establishing stakeholder relationships in the areas of our facilities, we have developed a strong knowledge of who our stakeholders are and have gained understanding of our stakeholders' issues and concerns.

Our principal stakeholder groups are listed in the following table.

TransAlta stakeholders

Non-governmental organizations	Community associations	Transmission facility operators
Regulators	Industry organizations	Communities
Charitable organizations/Non-profit	Standards organizations	Retirees
All levels of government	Media	Residents/Landowners
Suppliers	Business partners	Investor organizations
Contractors	Unions/Labour organizations	Financial institutions
Government agencies	Forest associations/Industry	Mineral rights owners
System operators	Oil and gas associations/Industry	Railroad owners
Customers	Think tanks	Utility owners
Shareholders	Academics	Employees

Stakeholder Engagement

In order to run our business successfully, we maintain open communication channels with our stakeholders. We are committed to timely and professional resolution in our dialogue with stakeholders.

Our stakeholder engagement practices are guided by regulatory requirements, industry best practices, international standards and corporate policies. We work internally and externally with each stakeholder to identify and mitigate further issues.

Examples of our methods of engagement are listed in the following table.

Information and communication	Dialogue and consultation	Relationship building
Open houses, town halls and public information sessions	In-person meetings with local groups and communities	Community advisory bodies
Newsletters, telephone conversations, emails and letters	Meetings with individual stakeholders (e.g., landowners and residents)	Capacity agreements
Websites	Targeted audience sessions	Sponsorships and donations
Social media postings	Tours of our facilities and sites	Hosting and attending events

A key focus of our work is to support business growth through proactive engagement with stakeholders in our geographic operating areas in Canada, the US and Australia to develop and maintain relationships, assess needs and fit and seek out collaborative opportunities. This helps ensure any stakeholder concerns are identified and can be addressed early in the development process, thereby minimizing project delays. We conduct consultation primarily during project development and construction phase and maintain engaged communication throughout operations to decommissioning phase.

Examples of stakeholder engagement in 2023 include: the Pinnacle project 1 and 2 open houses, SunHills Solar project open house, two Riplinger project open houses and ongoing engagement on the Kent Hills rehabilitation plan.

Community Investments

In 2023, TransAlta contributed approximately $3.2 million in donations and sponsorships (2022 – $2.3 million), with a continued focus in three priority areas: youth and education, environmental leadership and community health and wellness.

One of our significant community investments each year is to United Way campaigns across Canada and the US. This year, TransAlta employees, retirees, contractors and the Company raised over $1.5 million for the United Way.

In 2023, TransAlta made a number of other significant investments, including the following highlights:

- Community Shelters – In 2023, TransAlta donated $40,000 to local shelters near our operating assets in Canada, US and Australia. This initiative recognizes the unprecedented need for employment services, families experiencing poverty and escaping violence and abuse.
- New Operation Support – In 2023, TransAlta donated $50,000 to local communities surrounding our new White Rock, Horizon Hill and Garden Plain operations. These initiatives recognize our commitment to supporting the communities in which we operate. Funding was designated to the local school libraries, school repairs and a local fire station.

- Centralia Coal Facility – Since 2012, TransAlta has maintained its commitment to invest US$55 million in the state of Washington and made the final annual payment in December 2023. Funds from this investment have been managed by the Centralia Coal Transition Board to support local community sponsorships including investments in the arts, colleges, energy technology, weatherization upgrades and supporting displaced workers with education and retraining opportunities. This completes a significant commitment for the transition of the Centralia coal facility.

Public Health and Safety

We are committed to protecting the public and our assets, as well as the physical, psychological and social well-being of our employees.

We specifically look to minimize the following risks:

- Harm to people;
- Damage to property;
- Operational liability; and
- Loss of organizational reputation and integrity.

We work to prevent incidents and lower our risk by administering security controls such as restricting physical access around and into our operating facilities. The use of security technology such as surveillance cameras and electronic access is utilized to ensure the control of secure areas. Regular audits and security risk assessments are conducted to ensure continuous improvement of the Security Management Program. Our Security Management Program is focused on the protection of people, property, information and reputation.

The Corporate Emergency Management Program prepares employees should an emergency incident occur. The program receives executive sponsorship and includes an emergency management policy and standard, which sets an expectation for employees to continuously prepare for emergencies. It provides the overarching framework for each business unit to provide an Emergency Response Plan and Business Continuity Plan. We implement our Incident Command System, which is a standardized on-scene emergency and incident management system that provides an organizational structure capable of responding to single or multiple incidents. Designed to aid in the management of resources during incidents, it combines facilities, equipment, personnel, procedures and communications operating within a common organizational structure. It is used as part of an all-hazards approach for incident management and is officially recognized for multi-agency response in emergency situations, however complex the incident might be.

We develop strong relationships with local emergency responders. We periodically conduct multi-agency training events at our facilities. This ensures continuous improvement and familiarity with our assets and builds strong communication channels for emergency response.

Our processes designate how we communicate with stakeholders in the event of a crisis. This is managed by our Crisis Communications Team. The team has the responsibility and goal to provide a unified message on behalf of the Company throughout the response and recovery, ensure all messaging is approved by the Incident Commander, co-ordinate messaging with any applicable external agencies and, if necessary, deploy to an incident site.

Annual training, exercise and drill requirements are adhered to by our employees operating at our facilities. The results are tracked, audited and presented at our annual executive review. The findings and recommendations assist in maintaining an effective program across the organization.

Data and Digital Asset Protection

We work diligently to protect our digital assets, including our corporate data and our digital identities that provide access into line of business applications. Cybersecurity threats that compromise these assets include the manipulation of data integrity, system and network hacking, use of social engineering tactics through email phishing and compromise of operations and infrastructure through the use of ransomware, credential breaches and attacks introduced through unknowing third-party vendors and service providers.

Given the ever-evolving nature of cyberattacks, we are consistently adapting our cybersecurity program to focus on three key pillars: technology, processes and people. Each of these pillars can be reinforced independently to address specific cybersecurity risks and threats through a comprehensive and multi-faceted program. TransAlta continually assesses our cyber threat level, implementing measures and controls to proactively mitigate internal and external cybersecurity risks and threats posed to the organization.

TransAlta's Cybersecurity Policy defines how we identify and manage cybersecurity risks and threats, as well as how we detect, respond, and recover from cybersecurity incidents. We comply with the North American Electric Reliability Corporation Critical Infrastructure Protection ("NERC CIP") requirements where applicable. The NERC CIP is a set of standards aimed at regulating, enforcing, monitoring and managing the security of the North American power system. These compliance standards apply specifically to address cybersecurity risks.

In 2023, there were no identified cybersecurity breaches to our technology environment. Refer to Cybersecurity Risk in the Governance and Risk Management section of this MD&A for further details.

Building a Diverse and Inclusive Workforce

Engaging our workforce, developing our employees, creating an equitable, diverse and inclusive work environment and minimizing safety incidents are the keys to human capital value creation at TransAlta and our most material areas for management. In 2023, we enhanced our ESG performance through our efforts to promote an equitable, diverse and inclusive workforce. This section covers sustainability factors of human capital as per guidance from the International Integrated Reporting Framework.

Equity, Diversity and Inclusion

TransAlta's commitment and focus on excellence in equity, diversity and inclusion ("ED&I") is found in our workplace and among our co-workers who advocate for the values of equity and inclusion at all working levels. This commitment is outlined in our Board and Workforce Diversity Policy and Diversity and Inclusion Pledge. We believe a strong focus on ED&I will create a culture of belonging, allowing our employees to bring their authentic selves to work where they can thrive, innovate, improve service to our customers and positively impact the communities that we live in.

In 2023, TransAlta executed the third year of our five-year ED&I strategy to achieve the goals and aspirations defined in our ED&I Pledge.

Gender Diversity

A number of case studies have highlighted the link between gender diversity and additional business value. TransAlta is an active supporter of gender diversity as a driver for value, but also as an ethical business practice. Our commitment to gender diversity in our business is evidenced by our female participation rates on both our executive team and Board. As of Dec. 31, 2023, women made up 26 per cent of our executive team and 46 per cent of our Board. These percentages are higher than the Canadian corporate averages of board seats held by women (29 per cent) and women on executive teams (21 per cent), according to data from all disclosing Canadian TSX-listed companies in Canada.

To further support female advancement, we have set targets to: (i) maintain equal pay for women in equivalent roles, (ii) achieve 50 per cent representation of women on our Board by 2030 and (iii) achieve 40 per cent representation of women among all employees by 2030. Currently, women employees represent 27 per cent of all employees. Though the majority of our operational roles are currently held by male employees, we remain committed to achieving the 40 per cent goal in this time period.

In 2023, we continued with the Women in Trades Scholarship that provides eligible students enrolled in post-secondary trade programs with financial support. In 2023, we also continued with a female apprenticeship program in our Generation business to strategically target the recruitment of female students and train them to gain valuable experiential learning in the trades.

Workforce Health and Safety

The safety of our people, communities and the environment is one of our core values. Our focus on Operational Excellence puts into action TransAlta's value of enabling a safe environment for our people and our communities. Operational Excellence is about powering and empowering our communities in a safe, environmentally-friendly and sustainable manner by ensuring our assets operate reliably and efficiently.

TransAlta's management systems underpin the delivery of safe, reliable and competitive electricity to our customers and partners. Our Total Safety Management System is a combination of recognized best practices in process safety, risk management, asset management, occupational health, safety and environmental management. Since expanding our Occupational Health and Safety program in 2015 to encompass Total Safety, we have transitioned from the development and implementation of this framework into continuous improvement, always striving to achieve our Target Zero vision to operate our business with zero unexpected asset failures and zero environmental, health and safety incidents.

We made significant progress on our safety culture transformation journey. Training and development initiatives were a top priority in which we completed behaviour-based safety training for all employees.

This training provides the tools and strategies to allow employees to influence their individual behaviours and encourage personal ownership over safety outcomes. It helps create a psychologically safe environment in our workplace as it encourages personal accountability towards safety.

In 2023, our strong safety performance has been supported by our strategic areas of focus: maturing our safety culture, understanding risk tolerance and standardization of safety information and systems. To support our safety cultural growth, new employees and leaders completed training modules designed to gain tools to understand their role in setting, building, and maintaining our safety culture. Through peer board sessions designed to embed an understanding of risk perception, risk tolerance and psychological safety, leaders held over 100 sessions across the fleet.

One of our key safety indicator is the TRIF, which tracks the number of injury incidents that require treatment beyond first aid, relative to total exposure hours worked. Our TRIF result for 2023 was 0.30 compared to 0.39 in 2022.

The following represents our corporate safety performance and includes employees and contractors:

Year ended Dec. 31	2023	2022	2021
Lost-time injuries	**1**	0	3
Medical aids	**4**	6	9
Restricted work injuries	**0**	0	5
Exposure hours	**3,362,000**	3,058,000	4,134,000
Total Recordable Injury Frequency (TRIF)	**0.30**	0.39	0.82

We focus on leading indicators and participation through Total Safety Reports (hazard, near miss, positive observations, and cybersecurity reports). Total Safety Report Frequency demonstrates the proactive activities, per worker per year, we are taking to identify and prevent an injury or loss from occurring. We also report and recognize positive behaviours in the workplace to enhance psychological safety. This allows us to not only respond to incidents if they occur but find opportunities to strengthen barriers and layers of protection to mitigate potential incidents. In 2023, we recorded 12.5 reports per worker, which is above our target of 12. Evidence of the positive impacts associated with strong engagement and a maturing safety culture is apparent in TransAlta's overall safety performance. In 2023, TransAlta was selected by Canada's Safest Employers to receive a Utilities and Electrical Employer Excellence Award. TransAlta was also recognized as the employer with the Best Wellness Program across all industries, excelling in the promotion and protection of employee overall wellness.

Organizational Culture and Structure

Our employees are central to value creation. Our corporate culture has evolved and adapted throughout our 112-year history. Our values are safety, innovation, sustainability, respect and integrity. These five values help provide clarity for our employees and guide our behaviour and decision-making. They also provide a foundation for leadership, collaboration, community support, personal growth and work-life balance. Through corporate initiatives and support throughout all levels of leadership, we encourage our employees to maximize their potential.

Culture Transformation

In 2022, we embarked on our culture transformation journey with the goal of becoming a culture of results, purpose and learning. We developed a three-year culture strategy, Culture Charter and Culture Roadmap that defines milestones. For alignment and transparency, all of these documents are available to our employees. Part of our culture transformation involves improving employee psychological safety in order to increase employees to speak up with a view to increase innovation, creativity and ultimately, results.

We conduct annual Employee Engagement Surveys to gauge the employee experience, and based on survey results, leaders created action plans to drive improvement and increase engagement at the business unit and team level.

Finally, we are focused on improving employee health and well-being. To increase awareness, we have launched education sessions on a variety of topics such as mental health, women's health, men's health, nutrition, resiliency, etc.

Organizational Structure

As of Dec. 31, 2023, we had 1,257 (2022 – 1,222) active employees. This number increased by one per cent from 2022 levels. With approximately 30 per cent of our employees being unionized, we strive to maintain open and positive relationships with union representatives and regularly meet to exchange information, listen to concerns and share ideas that further our mutual objectives. Collective bargaining is conducted in good faith and we respect the rights of employees to participate in collective bargaining.

Our organizational structure changed in 2023. Our business continues to operate four generating segments, with Gas, Wind and Solar, Hydro and Energy Transition, with support from our Corporate and Growth Business Units. Our operations portfolio is run by a single leadership team, which provides operational and financial synergies, thus enhancing our competitiveness.

Employee Retention and Recognition

ESG-Linked Compensation

At TransAlta, we have linked our ESG performance to our employees' compensation including that of our executive leadership team. Our annual and long-term incentive pay for performance plans are linked to TransAlta achieving various ESG goals, where the targets and metrics are reviewed and approved annually by our Board of Directors and further outlined in our annual compensation plans.

In 2023, 20 per cent of our annual incentive plan was linked to achieving specific ESG targets: 10 per cent referred to our organizational culture improvements and 10 per cent was linked to safety. Further, 30 per cent of our annual incentive plan was tied to growth, which is focused on expanding TransAlta's portfolio of renewable generation and will help reduce the Company's overall GHG emissions intensity. Our long-term incentive plans include strategic goals related to our focus on clean electricity, strong renewables growth, leading in ESG policy development, delivering on our culture plan and our ED&I strategy. Refer to the Management Proxy Circular for additional details on our ESG related compensation.

Employee Performance and Recognition

Coaching, feedback and management are fundamental to our performance philosophy, with leaders and employees being asked to participate in regular meetings to discuss work progress, professional and career development throughout the year.

We strive to be an employer of choice through our HR and total rewards programs, which include pay-for performance incentive plans, as reviewed and approved by the Board of Directors. TransAlta's annual and long-term incentive plans are designed to measure and recognize employees' contributions towards metrics and targets. In order to motivate and engage employees in a timely manner, we continue to utilize employee recognition programs, including a quarterly recognition program and a peer-to-peer recognition program.

Talent Development

TransAlta places significant focus on talent development and retention of its employees. Annually, employees complete a combination of optional, mandatory and customized training as part of their roles. All employees have access to learning sessions from speakers who are experts on topics as varied as psychological safety, ED&I, mental and physical health, culture, financial wellness, core skills and leadership development.

Progressive Environmental Stewardship

We continue to increase financial value from natural or environmental capital-related business activities, while minimizing our environmental footprint and potential risk factors related to environmental impacts. This section covers natural capital management as per guidance from the International Integrated Reporting Framework.

Environmental Strategy

All energy sources used to generate electricity have impact on the environment. While we are pursuing a business strategy that includes investing in renewable energy resources such as wind, hydro and solar, we also believe that natural gas will continue to play an important role in meeting energy needs during our clean electricity transition. Our environmental management processes support our corporate strategy of ceasing GHG-intensive coal operations. In 2026, our generation mix will be made up of natural gas and renewable energy only.

Reducing the environmental impact of our activities benefits not only our operations and financial results, but also the communities in which we operate. We have a proactive approach to minimizing environmental risks and we anticipate this strategy will benefit our competitive position as stakeholders and society at large place an increasing emphasis on successful environmental management. Our Environmental Policy defines how we are integrating the protection of nature and the environment within TransAlta's strategy, our Total Safety Management System, as well as the principles of conduct for the management of natural resources.

Environmental Management System

At TransAlta, we operate our facilities in line with best practices related to environmental management standards. Our environmental management processes are verified annually to ensure we continuously improve our environmental performance. Our knowledge of environmental management systems ("EMS") has matured since we aligned our processes in accordance with the internationally recognized ISO 14001 EMS standard. Currently, the most material natural or environmental capital impacts to our business are GHG emissions, air emissions (i.e., pollutants) and energy use. Other material impacts that we manage and track performance on via our environmental management practices include land use, water use and waste management.

In addition to our environmental management practices, we are subject to environmental laws and regulations that affect aspects of our operations, including air emissions, water quality, wastewater discharges and the generation, transport and disposal of waste and hazardous substances. The Company's activities have the potential to damage natural habitat, impact vegetation and wildlife, or cause contamination to land or water that may require remediation under applicable laws and regulations. These laws and regulations require us to obtain and comply with a variety of environmental registrations, licenses, permits and other approvals. The environmental regulations in the jurisdictions in which we operate are robust. Both public officials and private individuals may seek to enforce environmental laws and regulations against the Company. We interact with a number of regulators on an ongoing basis.

Environmental Performance

Our performance on managing environmental aspects, reducing our environmental impact and capitalizing on environmental initiatives includes the following:

Biodiversity

The importance of environmental protection and biodiversity is outlined in our Environmental Policy as a corporate responsibility for TransAlta and a responsibility of each employee and contractor working on TransAlta's behalf. In 2022, the Company adopted the target to "achieve zero biodiversity-related incidents". This means zero biodiversity-related incidents that affected habitats and species included on the Red List of the International Union for Conservation of Nature ("IUCN") from near-threatened to critically endangered.

The following represents our biodiversity incidents in accordance with the IUCN Red List classification:

Year ended Dec. 31	2023	2022	2021
Critically Endangered	**0**	0	0
Endangered	**0**	0	0
Vulnerable	**0**	0	0
Near threatened	**0**	0	0
Total biodiversity-related incidents	**0**	0	0

Overseeing Biodiversity-Related Issues

TransAlta's GSSC assists the Board in fulfilling its oversight responsibilities with respect to the Company's monitoring of environmental regulations, public policy changes and the development of strategies, policies and practices for the environment. For further information, refer to the Sustainability Governance section of this MD&A.

Assessing Biodiversity Impacts of Our Value Chain

We consider the biodiversity impact at all of our existing operations and the biodiversity impacts of all new growth projects are evaluated in line with regulatory compliance and with respect to TransAlta's focus on biodiversity health. Details on how we assess biodiversity impacts of our value chain are presented in the sections below.

Growth

Each new TransAlta development project must complete an in-depth environmental assessment (as prescribed by the local regulation and in line with our own assessment practices) describing baseline environmental conditions, identifying potential effects and developing mitigation strategies for identified environmental sensitivities prior to construction and operation. These assessments have been specifically designed to meet the environmental information requirements of the respective regions in which we operate while identifying alignment with the intent of the standards and/or regulations applicable to these jurisdictions. Typically, our renewable projects are greenfield development projects that require a higher level of evaluation compared to our gas projects, which primarily integrate into existing industrial facilities.

In addition, each greenfield development project has a detailed community engagement plan designed to ensure all potentially impacted host landowners, stakeholders, agencies, businesses, non-governmental organizations ("NGOs"), environmental NGOs and Indigenous communities understand the nature of the projects, have multiple and varied opportunities for engagement and feedback and are able to engage in meaningful dialogue and discussion with TransAlta and its representatives. The ultimate goal is addressing, resolving and mitigating stakeholder or Indigenous community concerns before filing major permit applications for all of our projects.

Day-to-day Operations

At our Alberta operations, in 2023, we continued with our Wildlife Monitoring Program designed to monitor wildlife abundance and species diversity in the study area over time. Based on these surveys, TransAlta has seen primarily stable or increasing biodiversity in the area, with various new bird species being detected over the years and incidents of vehicle collisions decreasing due to lower speed limit restrictions. Some animal population sizes fluctuate in the area based on weather conditions and available ground cover.

Our natural gas operations have a relatively limited impact on biodiversity. The facilities are frequently constructed adjacent to existing industrial operations and TransAlta may not always be the holder of the environmental permits. The land area these facilities occupy is also generally relatively small. One exception is our Sarnia cogeneration facility. This facility is made up of 260 acres of brownfield industrial land, some of which contains areas with tall grasses and potential wildlife. Care will be taken at the time of redevelopment of this land to minimize impact to species-at-risk through the completion of species-at-risk surveys as well as performing certain construction activities outside of nesting periods. For all sites that are under our environmental scope, we adhere to all relevant environmental compliance permits.

At our hydro facilities, a major focus is on reducing the impact on fish and its habitat. We adhere to provincial and federal regulations and operate in accordance with facility approvals. We continue to work toward operational improvement and regularly review our Environmental Operational Management Plans to ensure our operating parameters are met.

At our wind and solar operations, an Operational Environmental Management Plan has been developed for each asset to ensure that our facilities use environmentally-sound and responsible practices that are based on a philosophy of continuous improvement of environmental protection. Examples of environmental initiatives to support our biodiversity focus include our bird and bat protection practices (installation of covers to protect birds from possible electrocution), a bird and bat mortality database (records all injuries and mortalities), environmentally-sensitive resource monitoring (monitoring sensitive wildlife features in and around our operating wind facilities), and long-term dataset collections (e.g., wildlife studies pre-construction and post-construction). In addition, we continue to collaborate with industry and the scientific community to address environmental concerns and impacts pertaining to biodiversity.

At our Centralia operations, in 2023, we completed a riparian reforestation plan for under-forested areas along the Skookumchuck River within our Skookumchuck Wildlife Habitat Management Area. We planted 15,620 trees along both sides of the river to maintain the river banks and decrease erosion, and we completed a vigorous weed control program to control the proliferation of invasive species; thus, improving overall habitat health. Additionally, we harvested approximately 97,300 board feet of timber consisting of diseased Red Alder and Douglas Fir to allow for the growth of healthy trees as part of our overall wildlife habit management program.

Energy Use

TransAlta uses energy in a number of different ways. We burn natural gas, diesel and coal (to the end of 2025 at

Centralia) to generate electricity. We harness the kinetic energy of water and wind to generate electricity. We also generate electricity from the sun. In addition to combustion of fuel sources, we also track combustion of gasoline and diesel in our vehicles and the electricity use and fuel use for heating (such as natural gas) in the buildings we occupy. Knowledge of how much energy we use allows us to optimize and create energy efficiencies. As an electricity generator, we continually and consistently look for ways to optimize and create efficiencies related to the use of energy.

The following captures our energy use (million gigajoules). Energy use increased by one (1) per cent in 2023 over 2022. Some values do not sum to the indicated total due to rounding. Zeros (0) indicate truncated values:

Year ended Dec. 31	2023	2022	2021
Hydro	**0**	0	0
Wind and Solar	**0**	0	0
Gas	**123**	130	118
Energy Transition	**73**	64	86
Corporate and Energy Marketing	**0**	0	0
Total energy use (million gigajoules)	**197**	195	204

Air Emissions

Our one remaining coal facility emits air emissions that we track, analyze and report to regulatory bodies. We also work on mitigation solutions depending on the type of air emission. We report our major air emissions from coal, which includes NO_x, SO_2, particulate matter and mercury. We continue reducing air emissions in our existing facilities through our conversion and retirement of coal units in Alberta (completed in 2021) and Washington State (planned completion by the end of 2025).

In 2022, we achieved our 2026 target of 95 per cent SO_2 and 80 per cent NO_x emissions reductions over 2005 levels. Since 2005, we have reduced SO_2 emissions by 98 per cent and NO_x by 83 per cent. In 2024, we will continue to review setting new environmental targets for air emissions.

None of our previous Alberta coal facilities are located within 50 kilometres of dense or urban populations and they all have been retired or converted to gas as of 2021. Our Centralia thermal facility in Washington State is located 40 kilometres from a dense or urban population. As per guidance from SASB, "a facility is considered to be located near an area of dense population if it is located within 49 kilometres of an area of dense population" (being deemed to be a "minimum population of 50,000 persons"). In 2023, the Centralia thermal facility accounted for 35 per cent of total NO_x, 99 per cent of total SO_2, 30 per cent of total particulate matter and 76 per cent of total mercury. The facility has two units and we retired one unit in 2020 and will retire the additional unit by the end of 2025, at which time air emissions from our coal facilities will be eliminated.

Our gas facilities emit sufficient levels of NO_x that trigger reporting obligations to national regulatory bodies. These gas facilities also produce trace amounts of SO_2 and particulate matter, but at levels that are deemed negligible and do not trigger any reporting requirements or compliance issues. Many of our gas facilities are located in very remote and unpopulated regions, away from dense urban areas. Our Sarnia, Windsor, Ottawa, Fort Saskatchewan and Ada gas facilities are our facilities with air emissions within 49 kilometres of dense or urban environments.

Our total air emissions in 2023 retained similar performance to 2022 levels. This is due to the completion of coal-to-gas conversions in previous years, which resulted in higher operational efficiency and reduction in air emissions. The slight increase of particulate matter is due to increased production of Centralia, which is the only remaining coal plant within our portfolio.

The following represents our material air emissions. Figures have been rounded for SO_2 (to the nearest one hundred), NO_x (to the nearest one thousand), particulate matter (to the nearest ten, when possible) and mercury (to the nearest whole number):

Year ended Dec. 31	2023	2022	2021
SO_2 (tonnes)	**1,100**	1,200	7,300
NO_x (tonnes)	**11,000**	11,000	15,000
Particulate matter (tonnes)	**460**	360	2,200
Mercury (kilograms)	**18**	21	41

Water

Our principal water use is for cooling and steam generation in our coal and gas facilities, but our hydro operations also require water flow for operations. Water for coal and gas operations is withdrawn primarily from rivers where we hold permits and must therefore adhere to regulations on the quality of discharged water. The difference between withdrawal and discharge, representing consumption, is due to several factors, which include evaporation loss and steam production for customers, which we are unable to recover.

In 2022, we achieved our water consumption reduction target to reduce fleet-wide water consumption (withdrawals minus discharge) by 20 million m^3 or 40 per cent in 2026 over the 2015 baseline. Water consumption in 2015 was 45 million m^3. This target is in line with the UN SDGs, specifically "Goal 6: Clean Water and Sanitation." In 2024, we will continue to review setting new environmental targets for water consumption.

In 2023, we withdrew approximately 273 million m^3 (2022 – 233 million m^3) and returned approximately 239 million m^3 (2022 – 207 million m^3) or 88 per cent. Overall, water consumption was approximately 34 million m^3 (2022 – 26 million m^3). Water consumption increased primarily due to an increase in production compared to last year. This is particularly observed in Centralia, our last transition-coal plant with the highest water consumption intensity.

The following represents our total water consumption (million m^3) over the last three years. Some values do not sum to the indicated total due to rounding. Figures below have been rounded to the nearest million m^3:

Year ended Dec. 31	2023	2022	2021
Water withdrawal	**273**	233	241
Water discharge	**239**	207	209
Total water consumption (million m^3)	**34**	26	32

Water Security

Our largest water withdrawal and discharge occurs at our Sarnia gas cogeneration facility (which produces both electricity and steam for our customers). The facility operates as a once-through, non-contact cooling system for our steam turbines. Despite large withdrawals from the adjacent St. Clair River to support our Sarnia operations, we return approximately 97 per cent of the water withdrawn. Water from this source is currently at low risk as per analysis from the SASB-endorsed Aqueduct Water Risk Atlas tool.

The Aqueduct Water Risk Atlas tool highlights that water risk is high at our interior and southern Western Australia facilities due to high interannual variability in the region. Interannual variability refers to wider variations in regional water supply from year to year. Our water supply at these facilities is provided at no cost under PPAs with our mining customers, hence our risk is significantly mitigated. In addition, our customers have developed conservation and re-use strategies aimed at recycling water for mining operational needs. All water used in the region is sourced from scheme water. With respect to gas and diesel turbine water use, water wash techniques and frequency of activities are continually modified to minimize consumption and environmental impact. Water used in our operations is returned to our customers, who repurpose this water for vegetation and dust suppression in their mining operations.

At the South Hedland facility in Western Australia, water risk is also high due to the risk of flooding in the region. The South Hedland facility was built above normal flood levels to mitigate potential risk from flooding. During a category 4 cyclone event in the area and associated flooding in the region in 2019, the South Hedland facility continued to generate power for the region. In addition, the South Hedland facility has developed a Water Efficiency Management Plan with Water Corporation WA, the principal supplier of water, wastewater and drainage services in Western Australia. Initiatives are aimed at reducing water consumption and costs through innovative technology and efficiencies identified through facility management.

Dam Safety

Our dam safety programs include all hydroelectric developments, constructed ponds and fluid retaining structures such as ash lagoons and canals, as well as associated equipment and structures and the personnel required to operate, maintain and inspect these items. They are governed through our Dam Safety Policy and Dam Safety Management System, which includes requirements on design, modification and decommissioning, operation, maintenance and surveillance, public safety, emergency management and risk management.

TransAlta's Board and its President and CEO oversee the effectiveness of our dam safety programs and receive regular updates. In 2022, a member of the Board was designated as the Company's Dam Safety Advisor to assist the Board in fulfilling its oversight role in regard to the Company's dam safety practices given the unique and technical aspects of dam safety. In addition, TransAlta engages an external Dam Safety Review Panel to provide external review of the program and its management, including overall assessment and benchmarking against other national and international programs. Our monitoring programs include:

- Regular operations and engineering inspections;
- Testing of critical equipment;
- Numerous instruments in the dams monitoring water level, temperature, movement, earthquake detection;
- Use of drones and satellite remote movement monitoring;
- Emergency plans and exercises with internal and external stakeholders; and
- Regular third-party reviews that are shared with the regulators.

We work closely with local stakeholders including conservation authorities and public agencies on watershed management, emergency planning and flood response. For example, in Southern Alberta, our hydroelectric facilities have played an increasingly important water management role following the flood of 2013. In 2021, we renewed our previous agreement with the Government of Alberta for another five years to manage water on the Bow River at our Ghost Reservoir facility to aid in potential flood mitigation efforts, as well as at our Kananaskis River System (which includes the Interlakes, Pocaterra and Barrier hydroelectric plants) for drought mitigation efforts. In 2022, we started decommissioning the Keephills Ash Lagoon, a facility that is no longer needed for ash storage following the coal-to-gas conversion of Keephills Unit 2. This three-year project will reshape the existing lagoon so that it is stable for the long term and is the first step towards delicensing the structure.

TransAlta is proud of its reputation in dam safety. We participate in the Canadian Dam Association, Dam Safety Interest Group of the Centre for Energy Advancement through Technological Innovation, United States Society on Dams, Canadian Geotechnical Society, Dam Safety Advisory Committee of the Alberta Chamber of Resources and Association of State Dam Safety Officials.

For information on our corporate emergency management program, refer to Public Health and Safety in the Engaging with Our Stakeholders to Create Positive Relationships section of this MD&A.

Waste

The importance of environmental protection and waste management is outlined in our Environmental Policy as a corporate responsibility for TransAlta and its employees, and contractors working on TransAlta's behalf. Our waste data is reported annually to a number of different regulatory bodies.

In 2023, our operations generated approximately 479,000 tonnes equivalent of waste (2022 – 204,000 tonnes). Of the total waste generated, 97 per cent was non-hazardous waste and 0.2 per cent was directed to landfill (2022 – 0.9 per cent). The main reason for the increase in total waste is due to the waste reuse. Since its retirement, we have been selling ash from our Highvale and Centralia Mine, which accounts for 95 per cent of the total waste generated.

The following represents our total waste production over the last three years. Figures have been rounded to the nearest one thousand:

Year ended Dec. 31	2023	2022	2021
Total waste generation (tonnes equivalent)	**479,000**	204,000	514,000
Waste to landfill (tonne eq.)	**1,000**	1,900	1,000
Waste recycled (tonne eq.)	**19,000**	22,000	31,000
Waste reuse (tonne eq.)	**457,000**	151,000	176,000
% of total waste to landfill	**0.2**	0.9	0.2
% of total waste: hazardous	**3**	9	5
% hazardous waste to landfill	**0.0**	0.6	1.0

Our reuse waste or byproduct waste is generally sold to third parties. Our operating teams are diligent at not only minimizing waste, but also maximizing recoverable value from waste. We have invested in equipment to capture byproducts from the combustion of coal, such as fly ash, bottom ash, gypsum and cenospheres, for subsequent sale. These non-hazardous materials add value to products like cement and asphalt, wallboard, paints and plastics.

Coal Ash Management

Given our transition off coal, we ceased producing fly ash waste in Canada at the end of 2021 and will no longer produce it past the end of 2025 in the US. In 2023, Lafarge Canada and TransAlta entered into an agreement that will advance low-carbon concrete projects in Alberta. The project will repurpose landfilled fly ash, a waste product from TransAlta's Highvale mine, which ceased operations in 2021. The ash will be used to replace cement in concrete manufacturing. By turning the recovered product into something marketable, it will continue to aid in reducing the amount of cement produced and consequent emissions while offering new job and economic growth opportunities. This innovative technology contributes to a circular economy and will reduce reclamation liabilities for TransAlta.

Land Use

Our largest land use had been associated with land disturbed by surface mining of coal, which ceased operations in 2021. Of the three mines we operated, the Whitewood mine in Alberta is completely reclaimed and the land certification process is ongoing. Our Centralia mine in Washington State is currently in the reclamation phase and we have adopted a target to fully reclaim this mine by 2040.

Our Highvale mine in Alberta ceased operations on Dec. 31, 2021, as part of our target to discontinue coal-fired power generation in Canada at the end of 2021. The mine reclamation of Highvale has been progressively executed as part of our regulatory approvals and our target is to have it fully reclaimed by 2046. In 2022, our reclamation team submitted our final reclamation plans. The updated plans align with community priorities for the reclaimed land. Our reclamation plans at Highvale are set out on a life-cycle basis and include contouring disturbed areas, re-establishing drainage, replacing topsoil and subsoil, re-vegetation and land management.

Our mining practices incorporate progressive reclamation where the final end use of the land is considered at all stages of planning and development. To date, we have reclaimed approximately 4,900 hectares, which is approximately 39 per cent of land disturbed (12,600 hectares).

Environmental Incidents and Spills

Protecting the environment supports healthy ecosystems and mitigates our environmental compliance risk and reputational risk. We maintain corporate incident management procedures, as part of our Total Safety Management System, for response, investigation and lessons learned to minimize environmental incidents. With respect to biodiversity management (management of ecosystems, natural habitats and life in the areas we operate), we seek to establish robust environmental research and data collection to establish scientifically sound baselines of the natural environment around our facilities to ensure we can accurately evaluate the level of significance to biodiversity following an incident. We closely monitor the air, land, water and wildlife in these areas to identify and curtail potential impacts.

In 2023, no regulatory non-compliance environmental incidents were recorded (2022 – one incident). No fines or environmental enforcement actions occurred.

Regulatory non-compliance environmental incidents follow:

Year ended Dec. 31	2023	2022	2021
Regulatory non-compliance environmental incidents	0	1	2

Regarding spills and releases, efforts are placed on providing immediate response to all environmental spills to ensure assessment, containment and recovery of spilled materials result in minimal impact to the environment.

The volume of spills in 2023 was zero (0) m^3 (2022 – 246 m^3).

Significant environmental incidents follow:

Year ended Dec. 31	2023	2022	2021
Significant environmental incidents	0	0	0

There is a potential that ash ponds associated with our retired coal mines could fail. The probability of this occurring is low, but the impact could be significant. We follow applicable environmental regulations with respect to our ash ponds and satisfy ourselves that management is adequate given our approach to dam safety and the robust regulations in the jurisdictions where we operate. Management includes periodic inspections and appropriate mitigation if issues are uncovered.

Weather

Abnormal weather events can impact our operations and give rise to risks. Due to the nature of our business, our earnings are sensitive to seasonal weather variations. Variations in winter weather affect the demand for electrical heating requirements while variations in summer weather affect the demand for electrical cooling requirements. These variations in demand translate into spot market price volatility. Variations in precipitation also affect water supplies, which in turn affect our hydroelectric assets. Also, variations in sunlight conditions can have an effect on energy production levels from our solar facilities. Variations in weather may be impacted by climate change resulting in sustained higher temperatures and rising sea levels, which could have an impact on our generating assets. Ice can accumulate on wind turbine blades in the winter months. The accumulation of ice on wind turbine blades depends on a number of factors, including temperature and ambient humidity. Accumulated ice can have a significant impact on energy yields and could result in the wind turbine experiencing more downtime. Extreme cold temperatures can also impact the ability of wind turbines to operate effectively and this could result in more downtime and reduced production. In addition, climate change could result in increased variability to our water and wind resources.

Our generation facilities and their operations are exposed to potential damage and partial or complete loss resulting from environmental disasters (e.g., floods, strong winds, wildfires, earthquakes, tornados and cyclones), equipment failures and other events beyond our control. Climate change can increase the frequency and severity of these extreme weather events. The occurrence of a significant event that disrupts the operation or ability of the generation facilities to produce or sell power for an extended period, including events that preclude existing customers from purchasing electricity, could have a material adverse effect. In certain cases, there is the potential that some events may not excuse us from performing our obligations pursuant to agreements with third parties. The fact that several of our generation facilities are located in remote areas may make access for repair of damage difficult. Refer to the Governance and Risk Management section of this MD&A for further discussion on weather-related risks.

Delivering Reliable and Affordable Energy

TransAlta's goal is to be a leading customer-centred clean electricity company, one that is committed to a sustainable future. Our strategy is focused on meeting our customers' need for clean, low-cost and reliable electricity, operational excellence and continual improvement in everything that we do. This section covers manufactured, intellectual and social and relationship capital management as per guidance from the International Integrated Reporting Framework.

Energy Affordability

TransAlta focuses on assisting commercial and industrial customers in managing their cost of energy. TransAlta has a full suite of procurement strategies and products with various terms available to our customers to assist in understanding and reducing their energy costs.

For customers interested in making a long-term commitment to obtain predictable costs, TransAlta has the experience to develop renewable energy facilities, battery energy storage systems and hybrid solutions, or long-term offtake agreements from its existing and future renewable and gas-fired facilities.

End-Use Efficiency and Demand

TransAlta's commercial and industrial customers have access to an extensive set of monthly reports providing detailed tracking of customer usage, allowing for corrective action as required, as well as cost-saving recommendations.

Our Power Factor Report advises customers if their sites are operating at less than a 90 per cent power factor so they can consider installing energy-efficient equipment. By reducing the customer's power system demand charge through power factor correction, the customer's site puts less strain on the electricity grid and reduces its carbon footprint. TransAlta's Site Health Report advises customers of a site whose peak demand has been permanently reduced for a variety of reasons from its initial in-service date. The customer may be paying a higher demand charge each month to the distribution company based on the original peak demand expected at the site. TransAlta collaborates with the customer and determines the new peak demand based on the customer's operation. The customer, working with the distribution company, may find it economic to buy down the distribution contract to reduce the monthly distribution costs going forward.

Grid Resiliency

As a large electricity generator, TransAlta works diligently to ensure the power we provide our customers is reliable, affordable and has low environmental impact. We provide decentralized and customized power solutions to industrial customers. In 2023, TransAlta completed the Northern Goldfields solar facilities in Western Australia to provide renewable solar electricity supported with a battery energy storage system to the Goldfields-based operations of BHP. We also supply power to centralized power systems and own and operate transmission grid infrastructure in Alberta that addresses system reliability needs.

In all jurisdictions where we operate, we work closely with the system operators to ensure overall supply adequacy and reliability of the grid. We consider a myriad of factors in our planning and operation decisions that could put grid resiliency at risk, including renewable energy intermittency, cyberattacks, extreme weather events and natural disasters. We are also committed to ensuring strong compliance with North American Electric Reliability Corporation standards and Alberta Reliability Standards for the power plant and transmission infrastructure that we own and operate.

As a Company, we are keenly focused on deploying clean power generation and new technology solutions to meet the emerging and future needs of the electric system that we operate in. For example, in Alberta, we brought online the first battery storage project, called WindCharger, in 2020 that is co-located with our Summerview II wind facility to create an emissions-free, peaking resource. This resource participates in the AESO's fast frequency response ancillary services market to support intertie operations. Beyond the fast frequency response, WindCharger introduces a resource with a response time that can be operated with a high level of reliability to support the growing need for primary frequency response and system frequency support and resiliency to support a decarbonized grid with a supply mix made up of intermittent renewable resources.

For more information on technologies to support grid resiliency, refer to the Enabling Innovation and Technology Adoption section of this MD&A. For more information on extreme weather events and natural disasters, refer to Weather in the Progressive Environmental Stewardship section of this MD&A.

Sustainability Governance

In order for an organization to truly integrate sustainability, it requires accountability at the Board and executive level. It requires an understanding of ESG issues and associated corporate actions to address these issues, while continuing to balance operations and growth.

Sustainability is overseen by TransAlta's GSSC of the Board. The GSSC assists the Board in fulfilling its oversight responsibilities with respect to the Company's monitoring of climate change, environmental, health and safety regulations, public policy changes and the development of strategies, policies and practices for climate change, environment, health and safety and social well-being, including human rights, working conditions and responsible sourcing.

The following policies help govern sustainability at TransAlta and are publicly available in the Governance section of the Investor Centre on our website:

- Corporate Code of Conduct
- Supplier Code of Conduct
- Whistleblower Policy
- Total Safety Management Policy
- Human Rights and Discrimination Policy
- Indigenous Relations Policy
- Board and Workforce Diversity Policy and Diversity and Inclusion Pledge
- Environmental Policy

In 2023, our sustainability memberships included key sustainability organizations and working groups such as the EXCEL Partnership, the Canadian Business for Social Responsibility and the Electricity Canada Sustainable Electricity Steering Committee, which all provide validation and support of our sustainability strategy and practices.

In 2022, we refreshed our material sustainability factors. They are presented below in alphabetical order.

- Air quality and emissions
- Asset integrity and grid resiliency
- Biodiversity and land management
- Climate change and greenhouse gas emissions
- Dam safety
- Energy use and conservation
- Equity, diversity and inclusion
- Ethics and business conduct
- Health, safety and well-being
- Human rights and labour practices
- Indigenous relationships and partnerships
- Information asset protection and cybersecurity
- Renewable energy and innovative technologies
- Security and emergency preparedness and response
- Stakeholder engagement and community investment
- Supply chain and sustainable sourcing
- Sustainability governance
- Sustainable finance
- Talent attraction, retention and development
- Waste management
- Water management

For additional details on governance, refer to the Governance and Risk Management section of this MD&A.

Governance and Risk Management

Our business activities expose us to a variety of risks and opportunities including, but not limited to, regulatory changes, rapidly changing market dynamics and increased volatility in our key commodity markets. Our goal is to manage these risks and opportunities so that we are in a position to develop our business and achieve our goals while remaining reasonably protected from an unacceptable level of risk or financial exposure. We use a multilevel risk management oversight structure to manage the risks and opportunities arising from our business activities, the markets in which we operate and the political environments and structures with which we interact.

Governance

The key elements of our governance practices are:

- Employees, management and the Board are committed to ethical business conduct, integrity and honesty;
- We have established key policies and standards to provide a framework for how we conduct our business;
- The Chair of our Board and all directors, other than our President and CEO, are independent within the meaning of National Instrument 58-101 — Disclosure of Corporate Governance Practices;
- The Board is comprised of individuals with a mix of skills, knowledge and experience that are critical for our business and our strategy;
- The effectiveness of the Board is achieved through robust annual evaluations and continuing education of our directors; and
- Our management and the Board facilitate and foster an open dialogue with shareholders and community stakeholders.

Commitment to ethical conduct is the foundation of our corporate governance model. We have adopted the following codes of conduct to guide our business decisions and everyday business activities:

- Corporate Code of Conduct, which applies to all employees and officers of TransAlta and its subsidiaries;
- Directors' Code of Conduct;
- Supplier's Code of Conduct;
- Finance Code of Ethics, which applies to all financial employees of the Company; and
- Energy Trading Code of Conduct, which applies to all of our employees engaged in energy marketing.

Our Corporate Code of Conduct outlines the standards and expectations we have for our employees, officers, directors, consultants and suppliers with respect to, among other things, the protection and proper use of our assets. The codes also provide guidelines with respect to securing our assets, avoiding conflicts of interest, respect in the workplace, social responsibility, privacy, compliance with laws, insider trading, environment, health and safety and our commitment to ethical and honest conduct. Our Corporate Code of Conduct and Directors' Code of Conduct each goes beyond the laws, rules and regulations that govern our business in the jurisdictions in which we operate; they outline the principal business practices with which all employees and directors must comply.

Our employees, officers and directors are reminded annually about the importance of ethics and professionalism in their daily work and must certify annually that they have reviewed and understand their responsibilities as set forth in the respective codes of conduct. This certification also requires our employees, officers and directors to acknowledge that they have complied with the standards set out in the respective code during the last calendar year.

The Board provides stewardship of the Company and ensures that the Company establishes key policies and procedures for the identification, assessment and management of principal risks and strategic plans. The Board monitors and assesses the performance and progress of the Company's goals through candid and timely reports from the CEO and the senior management team. We have also established an annual evaluation process whereby our directors are provided with an opportunity to evaluate the Board, Board committees, individual directors and the Chair of the Board's performance.

In order to allow the Board to establish and manage the financial, environmental and social elements of our governance practices, the Board has delegated certain responsibilities to the AFRC, GSSC, the Human Resources Committee (the "HRC") and the Investment Performance Committee ("IPC").

The AFRC, consisting of independent members of the Board, provides assistance to the Board in fulfilling its oversight responsibility relating to the integrity of our consolidated financial statements and the financial reporting process; the systems of internal accounting and financial controls; the internal audit function; the external auditors' qualifications and terms and conditions of appointment, including remuneration, independence, performance and reports; and the legal and risk compliance programs as established by management and the Board. The AFRC approves our Commodity and Financial Exposure Management policies and reviews quarterly ERM reporting.

The GSSC is responsible for developing and recommending to the Board a set of corporate governance principles applicable to the Company and for monitoring compliance with these principles. The GSSC is also responsible for Board recruitment, succession planning and for the nomination of directors to the Board and its committees. In addition, the GSSC assists the Board in fulfilling its oversight responsibilities with respect to the Company's monitoring of climate change, environmental, health and safety regulations, public policy changes and the development of strategies, policies and practices for climate change, environmental, health and safety and social well-being, including human rights, working conditions and responsible sourcing. The GSSC also receives an annual report on the annual codes of conduct certification process. For further information on the Board's oversight of climate-related factors, refer to the Climate Change Governance in the ESG section of this MD&A.

In regards to overseeing and seeking to ensure that the Company consistently achieves strong environment, health and safety ("EH&S") performance, the GSSC undertakes a number of actions that include: (i) receiving regular reports from management regarding environmental compliance, trends and TransAlta's responses; (ii) receiving reports and briefings on management's initiatives with respect to changes in climate change legislation, policy developments as well as other draft initiatives and the potential impact such initiatives may have on our operations; (iii) assessing the impact of the GHG policies implementation and other legislative initiatives on the Company's business; (iv) reviewing with management the EH&S policies of the Company; (v) reviewing with management the health and safety practices implemented within the Company, as well as the evaluation and training processes put in place to address problem areas; (vi) discussing with management ways to improve the EH&S processes and practices; (vii) considering and recommending our sustainability targets to the Board and evaluating our performance against such targets; and (viii) reviewing the effectiveness of our response to EH&S issues and any new initiatives put in place to further improve the Company's EH&S culture.

The HRC is empowered by the Board to review and approve key compensation and human resources policies of the Company that are intended to attract, recruit, retain and motivate employees of the Company. The HRC also makes recommendations to the Board regarding the compensation of the CEO, including the review and adoption of equity-based incentive compensation plans, the adoption of human resources policies that support human rights and ethical conduct and the review and approval of executive management succession and development plans.

The IPC is empowered by the Board to oversee management's investment conclusions and the execution of major, Board-approved capital expenditure projects that further the Company's strategic plans. The IPC provides assistance to the Board in fulfilling its oversight responsibilities with respect to broadly reviewing and monitoring project management and control processes, financial profile, capital costs, procurement practices and project schedules in a more in-depth manner than time permits during regularly scheduled Board meetings.

The responsibilities of other stakeholders within our risk management oversight structure are described below:

The CEO and executive management review and report on key risks quarterly. Specific Trading Risk Management reviews are held monthly by the Commodity Risk and Compliance Committee and weekly by the commodity risk team, the commercial managers in Trading and Marketing and the Executive Vice-President, Finance and Chief Financial Officer.

The Investment Committee is a management committee chaired by our Senior Vice-President, M&A, Strategy and Treasurer and comprises the President and Chief Executive Officer; Executive Vice-President, Finance and Chief Financial Officer; Executive Vice-President, Generation; Executive Vice-President, Commercial and Customer Relations; and Vice-President, Strategic Finance and Investor Relations. It reviews and approves all major capital expenditures including growth, productivity, life extensions and major coal outages. Projects that are approved by the Investment Committee will then be put forward for approval by the Board, if required.

The Commodity Risk & Compliance Committee is chaired by our Executive Vice-President, Finance and Chief Financial Officer and comprises at least three members of senior management. It oversees the risk and compliance program in trading and ensures that this program is adequately resourced to monitor trading operations from a risk and compliance perspective. It also ensures the existence of appropriate controls, processes, systems and procedures to monitor adherence to policy.

The Hydro Operating Committee consists of two members who are Brookfield employees with expertise in hydro facility management and two TransAlta members. This committee was formed in 2019 for the purpose of collaborating on matters in connection with the operation and maximization of the value of TransAlta's Alberta Hydro Assets. It is delivering on its objectives by reviewing the operating, maintenance, safety and environmental aspects of TransAlta's Alberta Hydro Assets and, following that review, providing expert advice and recommendations to TransAlta's hydro operational team. The Hydro Operating Committee has an initial term of six years, which can be extended for an additional two years.

TransAlta is listed on the Toronto Stock Exchange and the New York Stock Exchange and is subject to the governance regulations, rules and standards applicable under both exchanges. Our corporate governance practices meet the following governance rules and guidelines of the TSX and Canadian Securities Administrators: (i) Multilateral Instrument 52-109 —

Certification of Disclosure in Issuers' Annual and Interim Filings; (ii) National Instrument 52-110 — *Audit Committees*; (iii) National Policy 58-201 — *Corporate Governance Guidelines*; and (iv) National Instrument 58-101 — *Disclosure of Corporate Governance Practices*. As a "foreign private issuer" under US securities laws, we are generally permitted to comply with Canadian corporate governance requirements. Additional information regarding our governance practices can be found in our most recent management information circular.

Risk Controls

Our risk controls have several key components:

Enterprise Tone

We strive to foster beliefs and actions that are true to and respectful of, our many stakeholders. We do this by investing in communities where we live and work, operating and growing sustainably, putting safety first and being responsible to the many groups and individuals with whom we work.

Policies

We maintain a comprehensive set of enterprise-wide policies. These policies establish delegated authorities and limits for business transactions, as well as allow for an exception approval process. Periodic reviews and audits are performed to ensure compliance with these policies. All employees and directors are required to sign a Corporate Code of Conduct on an annual basis.

Reporting

On a regular basis, residual risk exposures are reported to key decision-makers including the Board, the AFRC, senior management and/or the Commodity Risk & Compliance Committee, as applicable. Reporting to this latter committee includes analysis of new risks, monitoring of status to risk limits, review of events that can affect these risks and discussion and review of the status of actions to minimize risks. This monthly reporting provides for effective and timely risk management and oversight.

Whistleblower System

We have a process in place where employees, contractors, shareholders or other stakeholders may confidentially or anonymously report any potential legal or ethical concerns, including concerns relating to accounting, internal control accounting, auditing or financial matters or relating to alleged violations of any laws or our Corporate Code of Conduct. These concerns can be submitted confidentially and anonymously, either directly to the AFRC or through TransAlta's toll-free telephone or online Ethics Helpline. The AFRC Chair is immediately notified of any material complaints and, otherwise, the AFRC receives a report at every quarterly committee meeting on all findings related to any material complaints or complaints relating to accounting or financial reporting or alleged breaches in internal controls over financial reporting.

Value at Risk and Trading Positions

Value at risk ("VaR") is one of the primary measures used to manage our exposure to market risk resulting from commodity risk management activities. VaR is calculated and reported on a daily basis. This metric describes the potential change in the value of our trading portfolio over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations.

VaR is a commonly used metric that is employed by industry to track the risk in commodity risk management positions and portfolios. Two common methodologies for estimating VaR are the historical variance/covariance and scenario analysis approaches. We estimate VaR using the historical variance/covariance approach. An inherent limitation of historical variance/covariance VaR is that historical information used in the estimate may not be indicative of future market risk. Stress tests are performed periodically to measure the financial impact to the trading portfolio resulting from potential market events, including fluctuations in market prices, volatilities of those prices and the relationships between those prices. We also employ additional risk mitigation measures. VaR at Dec. 31, 2023, associated with our proprietary commodity risk management activities was $4 million (2022 – $4 million). Refer to the Risk Factors – Commodity Price Risk section of this MD&A below for further discussion.

Risk Factors

Risk is an inherent factor of doing business. The following section addresses some, but not all, risk factors that could affect our future plans, performance, results or outcomes and our activities in mitigating those risks. These risks do not occur in isolation, but must be considered in conjunction with each other. Further information on the Company's risk factors can be found in the Risk Factors section of the AIF, which risk factors are hereby incorporated by reference and available on our website at www.transalta.com and under our profile on SEDAR+ at www.sedarplus.ca and on EDGAR at www.edgar.gov.

A reference herein to a material adverse effect on the Company means such an effect on the Company or its business, operations, financial condition, results of operations and/or its cash flows, as the context requires.

For some risk factors, we show the after-tax effect on net earnings (loss) of changes in certain key variables. The analysis is based on business conditions and production volumes in 2023. Each item in the sensitivity analysis assumes all other potential variables are held constant. While these sensitivities are applicable to the period and the magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or for a greater magnitude of changes. The changes in rates should also not be assumed to be proportionate to earnings in all instances.

Volume Risk

Volume risk relates to the variances from our expected production. The financial performance of our hydro, wind and solar operations is highly dependent upon the availability of their input resources in a given year. Shifts in weather or climate patterns, seasonal precipitation and the timing and rate of melting and runoff may impact the water flow to our facilities. The strength and consistency of the wind resource at our facilities impacts production. The operation of thermal facilities can also be impacted by ambient temperatures and the availability of water and fuel. Where we are unable to produce sufficient quantities of output in relation to contractually specified volumes, we may be required to pay penalties or purchase replacement power in the market.

We manage volume risk by:

- Actively managing our assets and their condition to be proactive in facility maintenance so that our facilities are available to produce when required;
- Monitoring water resources throughout Alberta to the best of our ability and optimizing this resource against real-time electricity market opportunities;
- Placing our facilities in locations we believe to have adequate resources to generate electricity to meet the requirements of our contracts. However, we cannot guarantee that these resources will be available when we need them or in the quantities that we require; and
- Diversifying our fuels and geography to mitigate regional or fuel-specific events.

The sensitivity of volumes to our net earnings is shown below:

Factor	Increase or decrease (per cent)	Approximate impact on net earnings (millions)
Availability/production	1	**$20**

Generation Equipment and Technology Risk

There is a risk of equipment failure due to wear and tear, latent defect, design error or operator error, among other things, which could have a material adverse effect on the Company. Although our generation facilities have generally operated in accordance with expectations, there can be no assurance that they will continue to do so. Our facilities are exposed to operational risks such as failures due to cyclic, thermal and corrosion damage in boilers, generators and turbines, as well as other issues that can lead to outages and increased production risk. If facilities do not meet availability or production targets specified in their PPA or other long-term contracts, we may be required to compensate the purchaser for the loss in the availability of production or record reduced energy or capacity payments. For merchant facilities, an outage can result in lost merchant opportunities. Therefore, an extended outage could have a material adverse effect on our business, financial condition, results of operations or our cash flows.

As well, we are exposed to procurement risk for specialized parts that may have long lead times. If we are unable to procure these parts when they are needed for maintenance activities, we could face an extended period where our equipment is unavailable to produce electricity.

We manage our generation equipment and technology risk by:

- Operating our facilities within defined industry standards that optimizes availability over their commercial operating life;
- Performing preventive maintenance in accordance with applicable industry practices, major equipment supplier recommendations and our operating experience;
- Adhering to comprehensive maintenance programs and regular turnaround schedules;
- Adjusting maintenance plans by facility to reflect equipment type, age and commercial risk;
- Having adequate business interruption insurance in place to cover extended forced outages;
- Having clauses in our PPAs and other long-term contracts that allow us to declare force majeure in the event of an unforeseen failure;
- Selecting and applying proven technology in our generating facilities, where practical;
- Where technology is newer, ensuring service agreements with equipment suppliers include appropriate availability and performance guarantees;
- Monitoring our fleet against industry performance to identify issues or advancements that may impact performance and adjusting our maintenance and investment programs accordingly;
- Negotiating strategic supply agreements with selected vendors to ensure key components are readily available in the event of a significant outage;
- Monitoring the condition of our assets and performing predictive analytics, and adjusting our maintenance programs to maintain availability;
- Entering into long-term arrangements with our strategic supply partners to ensure availability of critical spare parts; and

- Implementing long-term asset management strategies that optimize the life cycles of our existing facilities and/or identify replacement requirements for generating assets.

Commodity Price Risk

We have exposure to movements in certain commodity prices, including the market price of electricity and fuels used to produce electricity in both our electricity generation and proprietary trading businesses.

We manage the financial exposure associated with fluctuations in electricity price risk by:

- Entering into long-term contracts that specify the price at which electricity, steam and other services are provided;
- Maintaining a portfolio of short-, medium- and long-term contracts to mitigate our exposure to short-term fluctuations in commodity prices;
- Purchasing natural gas coincident with production for merchant facilities so spot market spark spreads are adequate to produce and sell electricity at a profit; and
- Ensuring limits and controls are in place for our proprietary trading activities.

In 2023, we had approximately 84 per cent (2022 – 83 per cent) of total production under short-term and long-term contracts and hedges. In the event of a planned or unplanned outage or other similar event, however, we are exposed to changes in electricity prices on purchases of electricity from the market to fulfil our supply obligations under these short- and long-term contracts.

We manage the financial exposure to fluctuations in the cost of fuels used in production by:

- Entering into long-term contracts that specify the price at which fuel is to be supplied to our facilities;
- Hedging emissions costs by entering into various emission trading arrangements; and
- Selectively using hedges, where available, to set prices for fuel.

In 2023, 86 per cent (2022 – 82 per cent) of our gas consumption used in generating electricity was contractually fixed or passed through to our customers and 100 per cent (2022 – 100 per cent) of our purchased coal was contractually fixed.

Actual variations in net earnings (loss) can vary from calculated sensitivities and may not be linear due to optimization opportunities, co-dependencies and cost mitigations, production, availability and other factors.

Natural Gas Supply and Price Risk

Having sufficient natural gas and natural gas transportation services available at our gas facilities is essential to maintaining the reliability and availability of those facilities. Ensuring adequate pipeline transportation service and natural gas supply for our gas units may be impacted by, among other things, the timing of receiving regulatory and other approvals for firm transportation commitments, weather-related events, work stoppages, system maintenance, variability in pipeline hydraulics pressure and flows and impacts due to other naturally caused events. Pricing of natural gas is driven by market supply and demand fundamentals for natural gas in North America and globally. We are exposed to changes in natural gas prices, which may impact the profitability of our facilities and how the facilities are dispatched into the market.

We manage gas supply and price risk by:

- Working to ensure that we have at least two pipelines supplying the gas used in electrical generation in Alberta;
- Contracting for firm gas delivery and supply;
- Monitoring the financial viability of gas producers and pipelines;
- Hedging gas price exposure; and
- Monitoring pipeline maintenance schedules and transportation availability.

Environmental Compliance Risk

Environmental compliance risks are risks to our business associated with existing and/or changes in environmental regulations. New emission reduction objectives for the power sector are being established by governments in Canada, Australia and the US. We anticipate continued and growing scrutiny by investors and other stakeholders relating to sustainability performance. These changes to regulations may affect our earnings by reducing the operating life of generating facilities and imposing additional costs on the generation of electricity through such measures as emission caps or taxes, requiring additional capital investments in emission abatement technology or requiring us to invest in offset credits. It is anticipated that these compliance costs will increase due to increased political and public attention to environmental concerns.

We manage environmental compliance risk by:

- Seeking continuous improvement in numerous performance metrics such as emissions, safety, land and water impacts and environmental incidents;
- Conducting environmental health and safety management system audits to assess conformance to our Total Safety Management System, which is designed to continuously improve performance;
- Committing significant experienced resources to work with regulators in Canada, Australia and the US to advocate that regulatory changes are well-designed and cost-effective;

- Developing compliance plans that address how to meet or surpass emission standards for GHG, mercury, SO_2 and NO_x, which will be adjusted as regulations are finalized;
- Purchasing carbon emissions reduction offsets or credits;
- Investing in renewable energy projects, such as wind, solar and hydro generation and storage technologies; and
- Incorporating change-in-law provisions in contracts that allow recovery of certain compliance costs from our customers.

We are committed to remaining in compliance with all environmental regulations relating to operations and facilities. Compliance with both regulatory requirements and management system standards is regularly audited through our performance assurance policy and results are reported to the GSSC.

Credit Risk

Credit risk is the risk to our business associated with changes in the creditworthiness of entities with which we have commercial exposures. This risk results from the ability of a counterparty to either fulfil its financial or performance obligations to us or where we have made a payment in advance of the delivery of a product or service. The inability to collect cash due to us or to receive products or services may have an adverse impact upon our net earnings (loss) and cash flows.

We manage our exposure to credit risk by:

- Establishing and adhering to policies that define credit limits based on the creditworthiness of counterparties;
- contract term limits and the credit concentration with any specific counterparty;
- Requiring formal sign-off on contracts that include commercial, financial, legal and operational reviews;
- Requiring security instruments, such as parental guarantees, letters of credit and cash collateral or third-party credit insurance if a counterparty goes over its limits. Such security instruments can be collected if a counterparty fails to fulfil its obligation; and
- Reporting our exposure using a variety of methods that allow key decision-makers to assess credit exposure by counterparty. This reporting allows us to assess credit limits for counterparties and the mix of counterparties based on their credit ratings.

If established credit exposure limits are exceeded, we take steps to reduce this exposure, such as by requesting collateral, if applicable, or by halting commercial activities with the affected counterparty. However, there can be no assurances that we will be successful in avoiding losses as a result of a contract counterparty not meeting its obligations.

As needed, additional risk mitigation tactics will be taken to reduce the risk to TransAlta. These risk mitigation tactics may include, but are not limited to, immediate follow-up on overdue amounts, adjusting payment terms to ensure a portion of funds are received sooner, requiring additional collateral, reducing transaction terms and working closely with impacted counterparties on negotiated solutions.

Our credit risk management profile and practices have not changed materially from Dec. 31, 2022. We had no material counterparty losses in 2023. We continue to keep a close watch on changes and trends in the market and the impact these changes could have on our energy trading business and hedging activities and will take appropriate actions as required, although no assurance can be given that we will always be successful.

The following table outlines our maximum exposure to credit risk without taking into account collateral held or right of set-off, including the distribution of credit ratings, as at Dec. 31, 2023:

	Investment grade (per cent)	Non-investment grade (per cent)	Total (per cent)	Total amount ($)
Trade and other receivables[1,2]	95	5	100	**807**
Long-term finance lease receivables	100	—	100	**171**
Risk management assets[1]	75	25	100	**203**
Loan receivable[2]	—	100	100	**26**
Total				**1,207**

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.

(2) Includes $26 million loan receivable included within other assets with a counterparty that has no external credit rating.

The maximum credit exposure to any one customer for commodity trading operations, including the fair value of open trading positions net of any collateral held, is $23 million (2022 – $64 million).

Counterparties enter into certain electricity and natural gas purchase and sale contracts for the purposes of asset-backed sales and proprietary trading. The terms and conditions of these contracts require the counterparties to provide collateral when the fair value of the obligation pursuant to these contracts is in excess of any credit limits granted. Downgrades in creditworthiness by certain credit rating agencies may impact our ability to enter into these contracts or any ordinary course contract, decrease the credit limits granted and increase the amount of collateral that may have to be provided. Certain existing contracts contain credit rating contingent clauses, that, when triggered, automatically increase costs under the contract or require additional collateral to be posted. Where the contingency is based on the lowest single rating, a one-level downgrade from a credit rating agency with an originally higher rating may not, however, trigger additional direct adverse impact.

Currency Rate Risk

We have exposure to various currencies as a result of our investments and operations in foreign jurisdictions, the earnings from those operations, the acquisition of equipment and services and foreign-denominated commodities from foreign suppliers, and our US and Australian dollar-denominated debt. Our exposures are primarily to the US and Australian currencies. Changes in the values of these currencies in relation to the Canadian dollar may affect our earnings, cash flows or the value of our foreign investments to the extent that these positions or cash flows are not hedged or the hedges are ineffective.

We manage our currency rate risk by establishing and adhering to policies that include:

- Hedging our net investments in US operations using US-denominated debt;
- Entering into forward foreign exchange contracts to hedge future foreign-denominated expenditures including our US-denominated senior debt that is outside the net investment portfolio; and
- Hedging our expected foreign operating cash flows. Our target is to hedge a minimum of 60 per cent of our forecasted foreign operating cash flows over a four-year period, with a minimum of 90 per cent in the current year, 70 per cent in the next year, 50 per cent in the third year and 30 per cent in the fourth year. The US and Australian exposure, net of debt service and sustaining capital expenditures, is managed with forward foreign exchange contracts.

The sensitivity of our net earnings to changes in foreign exchange rates has been prepared using management's assessment that an average $0.03 increase or decrease in the US or Australian currencies relative to the Canadian dollar is a reasonable potential change over the next quarter and is shown below:

Factor	Increase or decrease	Approximate impact on net earnings (millions)
Exchange rate	$0.03	**$14**

Liquidity Risk

Liquidity risk relates to our ability to access capital to be used to fund capital projects, refinance debt and pay liabilities, engage in trading and hedging activities and general corporate purposes. Credit ratings facilitate these activities and changes in credit ratings may affect our ability and/or the cost of accessing capital markets, or establishing normal course derivative or hedging transactions, including those undertaken by our Energy Marketing segment.

We continue to focus on maintaining our financial position and flexibility. Credit ratings issued for TransAlta, as well as the corresponding rating agency outlooks, are set out in the Financial Capital section of this MD&A. Credit ratings are subject to revision or withdrawal at any time by the rating organization and there can be no assurance that TransAlta's credit ratings and the corresponding outlook will not be changed, resulting in the adverse possible impacts identified above.

As at Dec. 31, 2023, we had liquidity of $1.7 billion comprising undrawn amounts under our committed credit facilities and cash on hand net of bank overdraft.

We manage liquidity risk by:

- Preparing and revising longer-term financing plans to reflect changes in business plans and the market availability of capital;
- Reporting liquidity risk exposure and risk management activities on a regular basis to the Commodity Risk & Compliance Committee, senior management and the AFRC;
- Maintaining a strong balance sheet;
- Maintaining sufficient undrawn committed credit lines to support potential liquidity requirements; and
- Monitoring trading positions.

Interest Rate Risk

Changes in interest rates can impact our borrowing costs. Changes in our cost of capital may also affect the feasibility of new growth initiatives.

We manage interest rate risk by establishing and adhering to policies that include:

- Employing a combination of fixed and floating rate debt instruments;
- Monitoring the mixture of floating and fixed rate debt and adjusting to ensure efficiency; and
- Opportunistically hedging probable debt issuances and outstanding variable rate borrowings using interest rate swaps.

At Dec. 31, 2023, approximately 14 per cent (2022 – nine per cent) of our total long-term debt was subject to changes in floating interest rates through a combination of floating rate debt and interest rate swaps.

The sensitivity of changes in interest rates upon our net earnings is shown below:

Factor	Increase or decrease (per cent)	Approximate impact on net earnings (millions)
Interest rate	50 bps	**$2**

London Interbank Offered Rate reform could impact interest rate risk with respect to the Company's Canadian dollar credit facilities and the Poplar Creek non-recourse bond held by a TransAlta subsidiary. The facilities reference the Canadian Dollar Offer Rate ("CDOR") for Canadian-dollar drawings, but include appropriate fallback language to replace this benchmark rate in the event of a benchmark transition. In addition, the non-recourse bond references the three-month CDOR. Cessation of the three-month CDOR will occur on June 28, 2024, which will impact the facilities and the non-recourse bond.

Coal Supply Risk

Having sufficient fuel available when required for generation is essential to maintaining our ability to produce electricity under contracts and for merchant sale opportunities. At Centralia, interruptions at our supplier's mine, the availability of trains to deliver coal and the financial viability of our coal suppliers could affect our ability to generate electricity.

We manage coal supply risk by:

- Sourcing the coal used at Centralia from different mine sources to ensure sufficient coal is available at a competitive cost;
- Contracting sufficient trains to deliver the coal requirements at Centralia;
- Ensuring coal inventories on hand at Centralia are at appropriate levels for usage requirements;
- Ensuring efficient coal handling and storage facilities are in place so that the coal being delivered can be processed in a timely and efficient manner;
- Monitoring and maintaining coal specifications and carefully matching the specifications mined with the requirements of our facilities;
- Monitoring the financial viability of Centralia suppliers; and
- Hedging diesel exposure in mining and transportation costs.

Project Management Risk

On capital projects, we face risks associated with cost overruns, delays and performance.

We manage project risks by:

- Ensuring all projects follow established corporate processes and policies;
- Identifying key risks during every stage of project development and ensuring mitigation plans are factored into capital estimates and contingencies;
- Reviewing project plans, key assumptions and returns with senior management prior to Board of Director approvals;
- Consistently applying project management methodologies and processes;
- Determining contracting strategies that are consistent with the project scope and scale to ensure key risks, such as labour and technology, are managed by contractors and equipment suppliers;
- Ensuring contracts for construction and major equipment include key terms for performance, delays and quality backed by appropriate levels of liquidated damages;
- Reviewing projects after achieving commercial operation to ensure learnings are incorporated into the next project;
- Negotiating contracts for construction and major equipment to lock in key terms such as price, availability of long lead equipment, foreign currency rates and warranties as much as is economically feasible before proceeding with the project; and
- Entering into labour agreements to provide security around labour cost, supply and productivity.

Human Resource Risk

Human resource risk relates to the potential impact upon our business as a result of changes in the workplace. Human resource risk can occur in several ways:

- Potential disruption as a result of labour action at our generating facilities;
- Reduced productivity due to turnover in positions;
- Inability to complete critical work due to vacant positions;
- Failure to maintain fair compensation with respect to market rate changes; and
- Reduced competencies due to insufficient training, failure to transfer knowledge from existing employees or insufficient expertise within current employees.

We manage this risk by:

- Possessing a labour relations strategy;
- Applying a human-centric approach that emphasizes the employee experience, including actively improving our workplace culture, focusing on ED&I strategies and offering health and wellness programming and initiatives;
- Focusing on employee learning and development;
- Monitoring industry compensation and aligning salaries with those benchmarks;
- Using incentive pay to align employee goals with corporate goals;
- Monitoring and managing target levels of employee turnover; and
- Ensuring employees have the appropriate training and qualifications to perform their jobs.

In 2023, approximately 30 per cent (2022 – 31 per cent) of our labour force was covered by 11 collective bargaining agreements (2022 – 11). In 2023, we successfully renegotiated three (2022 – six) collective bargaining agreements. Of these three agreements, one agreement is for a three-year duration, one agreement is for a two-year duration and one agreement is a one-year duration. We expect to renegotiate five collective bargaining agreements in 2024. Any problems in negotiating these collective bargaining agreements could lead to higher employee costs and a work stoppage or strike, which could have a material adverse effect on us.

Regulatory and Political Risk

Regulatory and political risk is the risk to our business associated with potential changes to the existing regulatory structures and the political influence upon those structures within each of the jurisdictions in which we operate. This risk can come from market regulation and re-regulation, increased oversight and control, structural or design changes in markets, or other unforeseen influences. Market rules are often dynamic and we are not able to predict whether there will be any material changes in the regulatory environment or the ultimate effect of changes in the regulatory environment on our business. This risk includes, among other things, uncertainties associated with the development of carbon pricing policies and funding.

We manage these risks systematically through our legal and regulatory groups and our compliance program, which is reviewed periodically to ensure its effectiveness. We also work with governments, regulators, electricity system operators and other stakeholders to resolve issues as they arise. We are actively monitoring changes to market rules and market design and we engage in industry and government-agency-led stakeholder engagement processes. Through these and other avenues, we engage in advocacy and policy discussions at a variety of levels. These stakeholder consultations have allowed us to engage in proactive discussions with governments and regulatory agencies over the longer term.

International investments are subject to unique risks and uncertainties relating to the political, social and economic structures of the respective country and such country's regulatory regime. We mitigate this risk through the use of non-recourse financing and insurance.

Transmission Risk

Access to transmission lines and transmission capacity for existing and new generation is key to our ability to deliver energy produced at our power facilities to our customers. The risks associated with the aging transmission infrastructure in the markets where we operate are increasing because new connections to the power system are consuming transmission capacity faster than it is being added by new transmission developments.

Reputation Risk

Our reputation is one of our most valued assets. Reputation risk relates to the risk associated with our business because of changes in opinion from the general public, private stakeholders, governments, financiers and other entities.

We manage reputation risk by:

- Striving as a neighbour and business partner, in the regions where we operate, to build viable relationships based on mutual understanding leading to workable solutions with our neighbours and other community stakeholders;
- Clearly communicating our business objectives and priorities to a variety of stakeholders on a routine and transparent basis;
- Applying innovative technologies to improve our operations, work environment and environmental footprint;
- Maintaining positive relationships with various levels of government;

- Pursuing sustainable development as a longer-term corporate strategy;
- Ensuring that each business decision is made with integrity and in line with our corporate values;
- Communicating the impact and rationale of business decisions to stakeholders in a timely manner; and
- Maintaining strong corporate values that support reputation risk management initiatives, including the annual Code of Conduct sign-off.

Corporate Structure Risk

We conduct a significant amount of business through subsidiaries and partnerships. Our ability to meet and service debt obligations is dependent upon the results of operations of our subsidiaries and partnerships and the payment of funds by our subsidiaries and partnerships in the form of distributions, loans, dividends or otherwise. In addition, our subsidiaries and partnerships may be subject to statutory or contractual restrictions that limit their ability to distribute cash to us.

Cybersecurity Risk

We rely on our information technology to process, transmit and store electronic information and data used for the safe operation of our assets. Over the past few years, geopolitical tensions and the pandemic have significantly impacted the cybersecurity ecosystem, increasing the frequency and diversity of cyberattacks, including threats of war driven cyberattacks (i.e., terrorism) against critical infrastructure and threat actors taking advantage of the pandemic (e.g., charity scams) and hybrid working environments. We anticipate that the cyber threat landscape will continue to evolve, with increasing threats of ransomware, compromised insider threats, supply chain attacks, advanced targeted phishing and artificial intelligence.

Cyber threats originate from various sources and vectors, from nation states, organized hacking groups or malware/ ransomware. The cyber threat landscape continues to evolve, as we see cyber threats shift their focus from traditional attacks against perimeter information technology systems, to more effective attacks, such as phishing and ransomware.

TransAlta has established a comprehensive cybersecurity program to manage cybersecurity risks through effective security practices and structured and tailored plans. As information technology /operation technology systems are integral to TransAlta's business operations, the risk of a cybersecurity incident threatens the safety of the public, TransAlta personnel and/or business functions, service delivery, reputation and profitability.

TransAlta maintains compliance to regulatory, legislative, and business requirements (e.g., NERC CIP, SOX, Privacy) by adopting industry endorsed standards and frameworks (e.g., National Institute of Standards and Technology ("NIST"), CIP/Reliability Standards) to implement a pragmatic fit-for-purpose cybersecurity program, implementing cybersecurity controls and processes under the following domains:

- Identify: TransAlta conducts comprehensive risk assessments to identify and document the organization's assets, systems and data, as well as potential risks and vulnerabilities.
- Protect: TransAlta implements security controls, policies and procedures to safeguard the organization's assets, systems and data from unauthorized access, use, disclosure, disruption, modification or destruction. This includes implementing access controls, encryption, firewalls and intrusion detection/prevention systems to protect the organization's networks and systems.
- Detect: TransAlta implements incident detection and response capabilities to detect and respond to cyber incidents. This includes monitoring systems, networks and data for suspicious activity.
- Respond: TransAlta has developed incident response plans, procedures and teams, as well as provided training and conducted exercises to ensure that these plans and procedures are operating effectively.
- Recover: TransAlta has developed disaster recovery and business continuity plans, and it conducts test exercises of these plans to ensure their effectiveness. This includes identifying critical systems, data and process to ensure the continuity of business operations, as well as implementing backup and recovery solutions to ensure that the organization's data can be restored in the event of a disaster.

Although complete cyber risk elimination is not achievable given the evolving cyber threat landscape, the security controls implemented to detect, prevent and respond to a cyber incident significantly reduce TransAlta's cyber risk and potential incident impact to acceptable levels. In addition, cyber insurance is utilized to further manage and transfer residual cyber risk to TransAlta's business. We continue to improve our overall security maturity and defense capabilities against cyber threats and align cybersecurity practices to industry standards, business objectives and regulatory compliance requirements.

General Economic Conditions

Changes in general economic conditions impact product demand, revenue, operating costs, the timing and extent of capital expenditures, the net recoverable value of PP&E, financing costs, credit and liquidity risk and counterparty risk.

Growth Risk

Our business plan includes targets for the growth of our fleet of generating assets through suitable acquisitions or contracting new build opportunities. There can be no assurance that we will be able to identify attractive growth opportunities in the future, that we will be able to complete growth opportunities that increase the amount of cash available for distribution, or that growth opportunities will be successfully integrated into our existing operations. The successful execution of the growth strategy requires careful timing and business judgment, as well as the resources to complete the due diligence and evaluation of such opportunities and to acquire and successfully integrate those assets into our business.

Income Taxes

Our operations are complex and located in several countries. The computation of the provision for income taxes involves tax interpretations, regulations and legislation that are constantly evolving. Our tax filings are subject to audit by taxation authorities. Management believes that it has adequately provided for income taxes as required by the *Income Tax Act* and IFRS, based on all information currently available.

The Company and its subsidiaries are subject to changing laws, treaties and regulations in and between countries.

Various tax proposals in the countries we operate in could result in changes to the basis on which deferred taxes are calculated or could result in changes to income or non-income tax expense. There has recently been an increased focus on issues related to the taxation of multinational corporations. A change in tax laws, treaties or regulations, or in the interpretation thereof, could result in a materially higher income or non-income tax expense that could have a material adverse impact on the Company.

The sensitivity of changes in income tax rates upon our net earnings is shown below:

Factor	Increase or decrease (per cent)	Approximate impact on net earnings (millions)
Tax rate	1	**$9**

Legal Contingencies

We are occasionally named as a party in various disputes, claims and legal or regulatory proceedings that arise during the normal course of our business. We review each of these claims, including the nature and merits of the claim, the amount in dispute or the remedy claimed and the availability of insurance coverage. There can be no assurance that any particular dispute, claim or proceeding will be resolved in our favour or our liabilities with respect to such claims will not have a material adverse effect on us or our business, operations or financial results. Refer to the Other Consolidated Analysis section of this MD&A for further details.

Other Contingencies

We maintain a level of insurance coverage deemed appropriate by management. There were no significant changes to our insurance coverage during renewal of the insurance policies on Dec. 31, 2023. Our insurance coverage may not be available in the future on commercially reasonable terms. There can be no assurance that our insurance coverage will be fully adequate to compensate for potential losses incurred. In the event of a significant economic event, the insurers may not be capable of fully paying all claims. All insurance policies are subject to standard exclusions.

Disclosure Controls and Procedures

Management is responsible for establishing and maintaining adequate internal control over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P"). During the year ended Dec. 31, 2023, the majority of our workforce supporting and executing our ICFR and DC&P continue to work on a hybrid basis. The Company has implemented appropriate controls and oversight for both in-office and remote work. There has been minimal impact to the design and performance of our internal controls.

ICFR is a framework designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements for external purposes in accordance with IFRS. Management has used the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) in order to assess the effectiveness of the Company's ICFR.

DC&P refer to controls and other procedures designed to ensure that information required to be disclosed in the reports we file or submit under securities legislation is recorded, processed, summarized and reported within the time frame specified in applicable securities legislation. DC&P include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in our reports that we file or submit under applicable securities legislation is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding our required disclosure.

Together, the ICFR and DC&P frameworks provide internal control over financial reporting and disclosure. In designing and evaluating our ICFR and DC&P, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives and as such may not prevent or detect all misstatements and management is required to apply its judgment in evaluating and implementing possible controls and procedures. Further, the effectiveness of ICFR is subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with policies or procedures may change.

Management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our ICFR and DC&P as of the end of the period covered by this MD&A. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as at Dec. 31, 2023, the end of the period covered by this MD&A, our ICFR and DC&P were effective.

Consolidated Financial Statements

Management's Report

To the Shareholders of TransAlta Corporation

The Consolidated Financial Statements and other financial information included in this annual report have been prepared by management. It is management's responsibility to ensure that sound judgment, appropriate accounting principles and methods, and reasonable estimates have been used to prepare this information. They also ensure that all information presented is consistent.

Management is also responsible for establishing and maintaining internal controls and procedures over the financial reporting process. The internal control system includes an internal audit function and an established business conduct policy that applies to all employees. In addition, TransAlta Corporation ("TransAlta") has a code of conduct that applies to all employees and is signed annually. The Corporate Code of Conduct can be viewed on TransAlta's website (www.transalta.com). Management believes the system of internal controls, review procedures and established policies provides reasonable assurance as to the reliability and relevance of financial reports. Management also believes that TransAlta's operations are conducted in conformity with the law and with a high standard of business conduct.

The Board of Directors (the "Board") is responsible for ensuring that management fulfils its responsibilities for financial reporting and internal controls. The Board carries out its responsibilities principally through its Audit, Finance and Risk Committee (the "Committee"). The Committee, which consists solely of independent directors, reviews the financial statements and annual report and recommends them to the Board for approval. The Committee meets with management, internal auditors and external auditors to discuss internal controls, auditing matters and financial reporting issues. Internal and external auditors have full and unrestricted access to the Committee. The Committee also recommends the firm of external auditors to be appointed by the shareholders.

John Kousinioris
President and Chief Executive Officer

Todd Stack
Executive Vice President, Finance and Chief Financial Officer

February 22, 2024

Management's Annual Report on Internal Control Over Financial Reporting

To the Shareholders of TransAlta Corporation

The following report is provided by management in respect of TransAlta Corporation's ("TransAlta" or the "Company") internal control over financial reporting (as defined in Rules 13a-15f and 15d-15f under the United States Securities Exchange Act of 1934 and National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings).

TransAlta's management is responsible for establishing and maintaining adequate internal control over financial reporting for TransAlta.

Management has used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") 2013 framework to evaluate the effectiveness of TransAlta's internal control over financial reporting. Management believes that the COSO 2013 framework is a suitable framework for its evaluation of TransAlta's internal control over financial reporting because it is free from bias, permits reasonably consistent qualitative and quantitative measurements of TransAlta's internal controls, is sufficiently complete so that those relevant factors that would alter a conclusion about the effectiveness of TransAlta's internal controls are not omitted and is relevant to an evaluation of internal control over financial reporting.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal controls over financial reporting are processes that involve human diligence and compliance and are subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting can also be circumvented by collusion or improper overrides. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process and it is possible to design safeguards into the process to reduce, though not eliminate, this risk.

TransAlta proportionately consolidates the joint operations of the Sheerness Generating Station and equity accounts for our investment in SP Skookumchuck Investment, LLC in accordance with International Financial Reporting Standards. Management does not have the contractual ability to assess the internal controls of these joint arrangements and associates. Once the financial information is obtained from these joint arrangements and associates it falls within the scope of TransAlta's internal controls framework. Management's conclusion regarding the effectiveness of internal controls does not extend to the internal controls at the transactional level of these joint arrangements and associates.

Included in the 2023 Consolidated Financial Statements of TransAlta for joint operations and equity accounted investments are three per cent and 12 per cent of the Company's total and net assets, respectively, as of Dec. 31, 2023, and seven per cent and 16 per cent of the Company's revenues and net earnings, respectively.

Changes in Internal Control over Financial Reporting

There has been no change in the Company's internal control over financial reporting that occurred during the year covered by this Annual Report that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Management has assessed the effectiveness of TransAlta's internal control over financial reporting, as at Dec. 31, 2023 and has concluded that such internal control over financial reporting was effective.

Ernst & Young LLP, who has audited the Consolidated Financial Statements of TransAlta for the year ended Dec. 31, 2023, has also issued a report on internal control over financial reporting under the standards of the Public Company Accounting Oversight Board (United States). This report is located on the following page of this Annual Report.

John Kousinioris
President and Chief Executive Officer

Todd Stack
Executive Vice President, Finance and
Chief Financial Officer

February 22, 2024

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of TransAlta Corporation

Opinion on Internal Control Over Financial Reporting

We have audited TransAlta Corporation's internal control over financial reporting as of December 31, 2023, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the "COSO criteria"). In our opinion, TransAlta Corporation (the "Company") maintained, in all material respects, effective internal control over financial reporting as of December 31, 2023, based on the COSO criteria.

As indicated in the accompanying Management's Annual Report on Internal Control over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of the joint operations of the Sheerness Generating Station and equity accounted joint venture of SP Skookumchuck Investment, LLC which are included in the 2023 consolidated financial statements of the Company and constituted 3% and 12% of total and net assets, respectively, as of December 31, 2023, and 7% and 16% of revenues and net earnings, respectively, for the year then ended. Our audit of internal control over financial reporting of the Company also did not include an evaluation of the internal control over financial reporting of the joint operations of the Sheerness Generating Station and equity accounted joint venture of SP Skookumchuck Investment, LLC.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated statements of financial position of TransAlta Corporation as of December 31, 2023 and 2022, the related consolidated statements of earnings (loss), comprehensive income (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2023, and the related notes and our report dated February 22, 2024 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the consolidated financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/Ernst & Young LLP

Chartered Professional Accountants

Calgary, Canada

February 22, 2024

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of TransAlta Corporation

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated statements of financial position of TransAlta Corporation (the "Company") as of December 31, 2023 and 2022, the related consolidated statements of earnings (loss), comprehensive income (loss), changes in equity and cash flows, for each of the three years in the period ended December 31, 2023, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2023 and 2022, and the financial performance and its cash flows for each of the three years in the period ended December 31, 2023, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2023, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated February 22, 2024 expressed an unqualified opinion thereon.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

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

Valuation of Long-Lived Assets related to certain cash generating units ("CGU"s) and Goodwill related to the Wind & Solar segment

Description of the Matter	As disclosed in notes 2(G), 2(H), 2(P)(I), 7 and 21 of the consolidated financial statements, the Company owns significant Wind & Solar generation assets and has recognized goodwill from historical acquisitions which must be tested for impairment at least annually or when indicators of impairment are present. The carrying value of Goodwill related to the Wind & Solar segment as at December 31, 2023 was $176 million and the recoverable amount of long-lived assets in the Wind & Solar segment that had indicators of impairment or impairment reversal during the year was $670 million. Determining the recoverable amounts for the Wind & Solar segment for the purposes of the goodwill impairment test and of certain CGUs in the Wind & Solar segment with indicators of impairment or impairment reversal ("Wind & Solar CGUs") for the asset impairment test was identified as a critical audit matter due to the significant estimation uncertainty and judgment applied by management in determining the recoverable amount, primarily due to the sensitivity of the significant assumptions to the future cash flows and the effect that changes in these assumptions would have on the recoverable amount. The estimates with a high degree of subjectivity include electricity production, sales prices, cost inputs, and determining the appropriate discount rate.
How We Addressed the Matter in Our Audit	We obtained an understanding of management's process for estimating the recoverable amount of the Wind & Solar segment and the Wind & Solar CGUs. We evaluated the design and tested the operating effectiveness of controls over the Company's processes to determine the recoverable amount. Our audit procedures to test the Company's recoverable amount of the Wind & Solar segment and the Wind & Solar CGUs with indicators of impairment or impairment reversal included, among others, comparing the significant assumptions used to estimate cash flows to current contracts with external parties and historical trends and obtaining historical electricity generation data to evaluate future electricity production forecasts. We assessed the historical accuracy of management's forecasts by comparing them with actual results and performed a sensitivity analysis to evaluate the assumptions that were most significant to the determination of the recoverable amount. We evaluated the Company's determination of future sales prices by comparing them to externally available third-party future electricity price estimates. We also involved our internal valuation specialist to assist in our evaluation of the discount rates, which involved benchmarking the inputs against available market data.

Valuation of Level III Derivative Instruments

Description of the Matter	As disclosed in notes 2(P)(IV), 14 and 25 of the consolidated financial statements, the Company enters into transactions that are accounted for as derivative financial instruments and are recorded at fair value. The valuation of derivative instruments classified as level III are determined using assumptions that are not readily observable. As at December 31, 2023 the fair value of the Company's derivative financial instruments classified as level III was a $147 million net risk management liability. Auditing the determination of fair value of level III derivative instruments that rely on significant unobservable inputs can be complex and relies on judgments and estimates concerning future prices, discount rates, credit value adjustments, liquidity and delivery volumes, and can fluctuate significantly depending on market conditions. Therefore, such determination of fair value was identified as a critical audit matter.
How We Addressed the Matter in Our Audit	We obtained an understanding of the Company's processes and we evaluated and tested the design and operating effectiveness of internal controls addressing the determination and review of inputs used in establishing level III fair values. Our audit procedures included, among others, testing a sample of level III derivative instrument internal models used by management and evaluating the significant assumptions utilized. We also compared management's future pricing assumptions, credit value adjustments, and liquidity assumptions to third-party data as well as comparing terms such as delivery volumes and timing to executed commodity contracts. We compared the delivery volume assumptions to historical information. We performed a sensitivity analysis to evaluate assumptions including future commodity prices, delivery volumes and discount rates. For a sample of level III derivative instruments, we involved our internal valuation specialist to assist in our evaluation of the appropriateness of the fair value by evaluating the key assumptions and methodologies.

/s/Ernst & Young LLP

Chartered Professional Accountants

We have served as auditors of TransAlta Corporation and its predecessor entities since 1947.

Calgary, Canada

February 22, 2024

Consolidated Statements of Earnings (Loss)

(in millions of Canadian dollars except where noted)

Year ended Dec. 31	2023	2022	2021
Revenues (Note 5)	3,355	2,976	2,721
Fuel and purchased power (Note 6)	1,060	1,263	1,054
Carbon compliance (Note 16)	112	78	178
Gross margin	2,183	1,635	1,489
Operations, maintenance and administration (Note 6)	539	521	511
Depreciation and amortization	621	599	529
Asset impairment charges (reversals) (Note 7)	(48)	9	648
Taxes, other than income taxes	29	33	32
Net other operating (income) loss (Note 8)	(47)	(58)	8
Operating income (loss)	1,089	531	(239)
Equity income (Note 9)	4	9	9
Finance lease income	12	19	25
Interest income	59	24	11
Interest expense (Note 10)	(281)	(286)	(256)
Foreign exchange gain (loss)	(7)	4	16
Gain on sale of assets and other	4	52	54
Earnings (loss) before income taxes	880	353	(380)
Income tax expense (Note 11)	84	192	45
Net earnings (loss)	796	161	(425)
Net earnings (loss) attributable to:			
TransAlta shareholders	695	50	(537)
Non-controlling interests (Note 12)	101	111	112
	796	161	(425)
Net earnings (loss) attributable to TransAlta shareholders	695	50	(537)
Preferred share dividends (Note 28)	51	46	39
Net earnings (loss) attributable to common shareholders	644	4	(576)
Weighted average number of common shares outstanding in the year (*millions*)	276	271	271
Net earnings (loss) per share attributable to common shareholders, basic and diluted (Note 27)	2.33	0.01	(2.13)

See accompanying notes.

Consolidated Statements of Comprehensive Income (Loss)

(in millions of Canadian dollars)

Year ended Dec. 31	2023	2022	2021
Net earnings (loss)	**796**	161	(425)
Other comprehensive income (loss)			
Net actuarial gains (losses) on defined benefit plans, net of tax[(1)]	**(5)**	37	37
Fair value loss on third-party investments, net of tax (Note 9)	**—**	(1)	—
Total items that will not be reclassified subsequently to net earnings (loss)	**(5)**	36	37
Gains (losses) on translating net assets of foreign operations, net of tax	**(6)**	21	(14)
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax[(2)]	**9**	(25)	—
Gains (losses) on derivatives designated as cash flow hedges, net of tax[(3)]	**41**	(556)	(200)
Reclassification of (gains) losses on derivatives designated as cash flow hedges to net earnings (loss), net of tax[(4)]	**58**	100	(8)
Total items that will be reclassified subsequently to net earnings (loss)	**102**	(460)	(222)
Other comprehensive income (loss)	**97**	(424)	(185)
Total comprehensive income (loss)	**893**	(263)	(610)
Total comprehensive income (loss) attributable to:			
TransAlta shareholders	**817**	(318)	(693)
Non-controlling interests (Note 12)	**76**	55	83
	893	(263)	(610)

(1) Net of income tax recovery of $1 million for the year ended Dec. 31, 2023 (2022 – $12 million expense, 2021 – $11 million expense).

(2) Net of income tax expense of $1 million for the year ended Dec. 31, 2023 (2022 – $3 million recovery, 2021 – nil).

(3) Net of income tax expense of $10 million for the year ended Dec. 31, 2023 (2022 – $138 million recovery, 2021 – $55 million recovery).

(4) Net of reclassification of income tax expense of $17 million for the year ended Dec. 31, 2023 (2022 – $26 million expense, 2021 – $2 million recovery).

See accompanying notes.

Consolidated Statements of Financial Position

(in millions of Canadian dollars)

As at Dec. 31	2023	2022
Current assets		
Cash and cash equivalents	**348**	1,134
Restricted cash (Note 24)	**69**	70
Trade and other receivables (Note 13)	**807**	1,589
Prepaid expenses and other	**48**	55
Risk management assets (Note 14 and 15)	**151**	709
Inventory (Note 16)	**157**	157
	1,580	3,714
Non-current assets		
Investments (Note 9)	**138**	129
Long-term portion of finance lease receivables (Note 17)	**171**	129
Risk management assets (Note 14 and 15)	**52**	161
Property, plant and equipment (Note 18)	**5,714**	5,556
Right-of-use assets (Note 19)	**117**	126
Intangible assets (Note 20)	**223**	252
Goodwill (Note 21)	**464**	464
Deferred income tax assets (Note 11)	**21**	50
Other assets (Note 22)	**179**	160
Total assets	**8,659**	10,741
Current liabilities		
Bank overdraft (Note 14)	**3**	16
Accounts payable and accrued liabilities (Note 13)	**797**	1,346
Current portion of decommissioning and other provisions (Note 23)	**35**	70
Risk management liabilities (Note 14 and 15)	**314**	1,129
Current portion of contract liabilities	**3**	8
Income taxes payable	**9**	73
Dividends payable (Note 27 and 28)	**49**	68
Current portion of long-term debt and lease liabilities (Note 24)	**532**	178
	1,742	2,888
Non-current liabilities		
Credit facilities, long-term debt and lease liabilities (Note 24)	**2,934**	3,475
Exchangeable securities (Note 25)	**744**	739
Decommissioning and other provisions (Note 23)	**654**	659
Deferred income tax liabilities (Note 11)	**386**	352
Risk management liabilities (Note 14 and 15)	**274**	333
Contract liabilities	**10**	12
Defined benefit obligation and other long-term liabilities (Note 26)	**251**	294
Equity		
Common shares (Note 27)	**3,285**	2,863
Preferred shares (Note 28)	**942**	942
Contributed surplus	**41**	41
Deficit	**(2,567)**	(2,514)
Accumulated other comprehensive loss (Note 29)	**(164)**	(222)
Equity attributable to shareholders	**1,537**	1,110
Non-controlling interests (Note 12)	**127**	879
Total equity	**1,664**	1,989
Total liabilities and equity	**8,659**	10,741

Commitments and contingencies (Note 36)

See accompanying notes.

On behalf of the Board:

John P. Dielwart
Director

Bryan D. Pinney
Chair of Audit, Finance and Risk Committee

Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income (loss)[1]	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2021	2,901	942	46	(2,453)	146	1,582	1,011	2,593
Net earnings	—	—	—	50	—	50	111	161
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and of tax	—	—	—	—	(4)	(4)	—	(4)
Net losses on derivatives designated as cash flow hedges, net of tax	—	—	—	—	(456)	(456)	—	(456)
Net actuarial gains on defined benefits plans, net of tax	—	—	—	—	37	37	—	37
Intercompany and third-party FVTOCI investments	—	—	—	—	55	55	(56)	(1)
Total comprehensive income (loss)	—	—	—	50	(368)	(318)	55	(263)
Common share dividends (Note 27)	—	—	—	(57)	—	(57)	—	(57)
Preferred share dividends (Note 28)	—	—	—	(46)	—	(46)	—	(46)
Shares purchased under NCIB program (Note 27)	(46)	—	—	(8)	—	(54)	—	(54)
Share-based payment plans and stock options exercised (Note 30)	8	—	(5)	—	—	3	—	3
Distributions declared to non-controlling interests (Note 12)	—	—	—	—	—	—	(187)	(187)
Balance, Dec. 31, 2022	2,863	942	41	(2,514)	(222)	1,110	879	1,989
Net earnings	**—**	**—**	**—**	**695**	**—**	**695**	**101**	**796**
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and tax	**—**	**—**	**—**	**—**	**3**	**3**	**—**	**3**
Net gains on derivatives designated as cash flow hedges, net of tax	**—**	**—**	**—**	**—**	**99**	**99**	**—**	**99**
Net actuarial gains on defined benefits plans, net of tax	**—**	**—**	**—**	**—**	**(5)**	**(5)**	**—**	**(5)**
Intercompany FVTOCI investments	**—**	**—**	**—**	**—**	**25**	**25**	**(25)**	**—**
Total comprehensive income	**—**	**—**	**—**	**695**	**122**	**817**	**76**	**893**
Common share dividends (Note 27)	**—**	**—**	**—**	**(65)**	**—**	**(65)**	**—**	**(65)**
Preferred share dividends (Note 28)	**—**	**—**	**—**	**(51)**	**—**	**(51)**	**—**	**(51)**
Shares purchased under normal course issuer bid ("NCIB") (Note 27)	**(80)**	**—**	**—**	**(7)**	**—**	**(87)**	**—**	**(87)**
Changes in non-controlling interests in TransAlta Renewables (Note 4)	**510**	**—**	**—**	**(625)**	**(64)**	**(179)**	**(630)**	**(809)**
Provision for repurchase of shares under the automatic share purchase plan (Note 27)	**(19)**	**—**	**—**	**—**	**—**	**(19)**	**—**	**(19)**
Share-based payment plans and stock options exercised (Note 30)	**11**	**—**	**—**	**—**	**—**	**11**	**—**	**11**
Distributions declared to non-controlling interests (Note 12)	**—**	**—**	**—**	**—**	**—**	**—**	**(198)**	**(198)**
Balance, Dec. 31, 2023	**3,285**	**942**	**41**	**(2,567)**	**(164)**	**1,537**	**127**	**1,664**

(1) Refer to Note 29 for details on components of and changes in, accumulated other comprehensive income (loss).

See accompanying notes.

Consolidated Statements of Cash Flows

(in millions of Canadian dollars)

Year ended Dec. 31	2023	2022	2021
Operating activities			
Net earnings (loss)	**796**	161	(425)
Depreciation and amortization (Note 37)	**621**	599	719
Gain on sale of assets and other	**(3)**	(32)	(54)
Accretion of provisions (Note 10 and 23)	**48**	49	32
Decommissioning and restoration costs settled (Note 23)	**(37)**	(35)	(18)
Deferred income tax expense (recovery) (Note 11)	**34**	127	(11)
Unrealized loss (gain) from risk management activities	**(36)**	385	(34)
Unrealized foreign exchange gain	**(9)**	(82)	(24)
Provisions and contract liabilities	**(1)**	19	(41)
Asset impairment charges (reversals) (Note 7)	**(48)**	9	648
Equity (income) loss, net of distributions from investments (Note 9)	**2**	(4)	(5)
Other non-cash items	**(27)**	(3)	40
Cash flow from operations before changes in working capital	**1,340**	1,193	827
Change in non-cash operating working capital balances (Note 33)	**124**	(316)	174
Cash flow from operating activities	**1,464**	877	1,001
Investing activities			
Additions to property, plant and equipment (Note 18 and 37)	**(875)**	(918)	(480)
Additions to intangible assets (Note 20 and 37)	**(13)**	(31)	(9)
Restricted cash (Note 24)	**1**	—	(1)
Repayment (advances) from loan receivable (Note 22)	**11**	18	(3)
Acquisitions, net of cash acquired	**—**	(10)	(120)
Investments (Note 9)	**(13)**	(10)	—
Proceeds on sale of Pioneer Pipeline	**—**	—	128
Proceeds on sale of property, plant and equipment	**29**	66	39
Realized gain (loss) on financial instruments	**18**	27	(6)
Decrease in finance lease receivable	**55**	46	41
Other	**(25)**	45	(16)
Change in non-cash investing working capital balances	**(2)**	26	(45)
Cash flow used in investing activities	**(814)**	(741)	(472)
Financing activities			
Net increase (decrease) in borrowings under credit facilities (Note 24 and 33)	**(46)**	449	(114)
Repayment of long-term debt (Note 24 and 33)	**(164)**	(621)	(92)
Issuance of long-term debt (Note 24 and 33)	**39**	532	173
Dividends paid on common shares (Note 27)	**(58)**	(54)	(48)
Dividends paid on preferred shares (Note 28)	**(51)**	(43)	(39)
Repurchase of common shares under NCIB (Note 27)	**(87)**	(52)	(4)
Proceeds on issuance of common shares	**5**	3	8
Realized gain (loss) on financial instruments	**(30)**	42	3
Acquisition of TransAlta Renewables (Note 4)	**(811)**	—	—
Distributions paid to subsidiaries' non-controlling interests (Note 12)	**(223)**	(187)	(156)
Decrease in lease liabilities (Note 24 and 33)	**(10)**	(9)	(8)
Financing fees and other	**1**	(13)	(4)
Change in non-cash financing working capital balances	**3**	(2)	(1)
Cash flow from (used in) financing activities	**(1,432)**	45	(282)
Cash flow from (used in) operating, investing and financing activities	**(782)**	181	247
Effect of translation on foreign currency cash	**(4)**	6	(3)
Increase (decrease) in cash and cash equivalents	**(786)**	187	244
Cash and cash equivalents, beginning of year	**1,134**	947	703
Cash and cash equivalents, end of year	**348**	1,134	947
Cash taxes paid	**94**	67	57
Cash interest paid	**277**	229	220
Cash interest received	**54**	20	7

See accompanying notes.

Notes to the Consolidated Financial Statements

(Tabular amounts in millions of Canadian dollars, except as otherwise noted)

1. Corporate Information

A. Description of the Business

TransAlta Corporation ("TransAlta" or the "Company") was incorporated under the Canada Business Corporations Act in March 1985. The Company became a public company in December 1992. The Company's head office is located in Calgary, Alberta.

Operating Segments

Generation Segments

The four generation segments of the Company are as follows: Hydro, Wind and Solar, Gas, and Energy Transition. The Company directly or indirectly owns and operates hydro, wind and solar, natural gas-fired facilities, a coal-fired facility and natural gas pipeline operations in Canada, the United States ("US") and Australia. Transmission in Canada is included within the Hydro segment while transmission in Australia is included in the Gas segment. The Wind and Solar segment includes the financial results, on a proportionate basis, of our investment in SP Skookumchuck Investment, LLC ("Skookumchuck"). Segment revenues are derived from the availability and production of electricity and steam as well as ancillary services.

Energy Marketing Segment

The Energy Marketing segment derives revenue and earnings from the trading of electricity, natural gas and environmental products across a variety of North American markets, excluding Alberta.

The Energy Marketing segment also performs services on behalf of certain assets outside of Alberta for the power marketing of available generating capacity as well as the procurement of the fuel and transmission needs for the fleet. Contracts of various durations for the forward sales of electricity and for the purchase of natural gas and transmission capacity are utilized. The results of these activities are included in the gross margin of the related generation segment. The Energy Marketing segment allocates charges to recognize the performance of these activities to the applicable generation segments.

Corporate Segment

The Corporate segment includes the Company's central finance, legal, administrative, corporate development, and investor relations functions. Activities and charges directly or reasonably attributable to other segments are allocated thereto.

B. Basis of Preparation

These Consolidated Financial Statements have been prepared by management in compliance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

The Consolidated Financial Statements have been prepared on a historical cost basis except for financial instruments, which are measured at fair value, as explained in the following accounting policies.

These Consolidated Financial Statements were authorized for issue by TransAlta's Board of Directors (the "Board") on Feb. 22, 2024.

C. Basis of Consolidation

The Consolidated Financial Statements include the accounts of the Company and the subsidiaries that it controls. Control exists when the Company is exposed, or has rights, to variable returns from its involvement with the subsidiary and has the ability to affect the returns through its power over the subsidiary. The financial statements of the subsidiaries are prepared for the same reporting period and apply consistent accounting policies as the parent company.

2. Material Accounting Policies

The Company has reviewed its material accounting policies. The definition of material that management has used to judgmentally determine disclosure is that information is material if omitting it or misstating it could influence decisions users make on the basis of financial information.

A. Revenue Recognition

I. Revenue from Contracts with Customers

The majority of the Company's revenues from contracts with customers are derived from the sale of generation capacity, electricity, thermal energy, environmental attributes and byproducts of power generation. The Company evaluates whether the contracts it enters into meet the definition of a contract with a customer at the inception of the contract and on an ongoing basis if there is an indication of significant changes in facts and circumstances. Contract modifications are accounted for as separate contracts when the consideration for the additional promised goods reflects a stand-alone selling price. Otherwise, contract modifications are accounted for as part of the existing contract. If the additional goods are not considered distinct the transaction price can be affected and adjustments to previously recognized revenue can occur. If the additional goods are distinct, the existing and modified contracts are treated together as a new contract, with impacts reflected prospectively from the modification date, which can include the blending of contract prices. Revenue is measured based on the transaction price specified in a contract with a customer. Revenue is recognized when control of the goods or services are transferred to the customer. For certain contracts, revenue may be recognized at the invoiced amount, as permitted using the invoice practical expedient, if such amount corresponds directly with the Company's performance to date. The Company excludes amounts collected on behalf of third parties from revenue.

Performance Obligations

Each promised good or service is accounted for separately as a performance obligation if it is distinct. The Company's contracts may contain more than one performance obligation.

Transaction Price

The Company allocates the transaction price in the contract to each performance obligation. Transaction price allocated to performance obligations may include variable consideration. Variable consideration is included in the transaction price for each performance obligation when it is highly probable that a significant reversal of the cumulative variable revenue will not occur. Variable consideration that has previously been constrained is assessed at each reporting period to determine whether the constraint is lifted. The consideration contained in some of the Company's contracts with customers is primarily variable and may include both variability in quantity and pricing, such as: revenues can be dependent upon future production volumes that are driven by customer or market demand or by the operational ability of the plant; revenues can be dependent upon the variable cost of producing the energy; revenues can be dependent upon market prices; and revenues can be subject to various indices and escalators.

When multiple performance obligations are present in a contract, the transaction price is allocated to each performance obligation in an amount that depicts the consideration the Company expects to be entitled to in exchange for transferring the good or service. The Company estimates the amount of the transaction price to allocate to individual performance obligations based on their relative stand-alone selling prices, which is primarily estimated based on the amounts that would be charged to customers under similar market conditions.

Recognition

The nature, timing of recognition of satisfied performance obligations and payment terms for the Company's goods and services are described below:

Good or service	Description
Capacity	Capacity refers to the availability of an asset to deliver goods or services. Customers typically pay for capacity for each defined time period (e.g., monthly) in an amount representative of the availability of the asset for the defined time period. Obligations to deliver capacity are satisfied over time and revenue is recognized using a time-based measure. Contracts for capacity are typically long term in nature. Payments are typically received from customers on a monthly basis.
Contract power	The sale of contract power refers to the delivery of units of electricity to a customer under the terms of a contract. Customers pay a contractually specified price for the output at the end of predefined contractual periods (e.g., monthly). Obligations to deliver electricity are satisfied over time and revenue is recognized using a units-based output measure (i.e., megawatt hours). Contracts for power are typically long term in nature and payments are typically received on a monthly basis.
Thermal energy	Thermal energy refers to the delivery of units of steam to a customer under the terms of a contract. Customers pay a contractually specified price for the output at the end of predefined contractual periods (e.g., monthly). Obligations to deliver steam are satisfied over time and revenue is recognized using a units-based output measure (i.e., gigajoules). Contracts for thermal energy are typically long term in nature. Payments are typically received from customers on a monthly basis.
Environmental attributes	Environmental attributes refers to the delivery of renewable energy certificates, green attributes and other similar items. Customers may contract for environmental attributes in conjunction with the purchase of power, in which case the customer pays for the attributes in the month subsequent to the delivery of the power. Alternatively, customers pay upon delivery of the environmental attributes. Obligations to deliver environmental attributes are satisfied at a point in time, generally upon delivery of the item.
Generation byproducts	Generation byproducts refers to the sale of byproducts from the use of coal in the Company's current US and previous Canadian coal operations. Obligations to deliver byproducts are satisfied at a point in time, generally upon delivery of the item. Payments are received upon satisfaction of delivery of the byproducts.

A contract liability is recorded when the Company receives consideration before the performance obligations have been satisfied. A contract asset is recorded when the Company has rights to consideration for the completion of a performance obligation before it has invoiced the customer. The Company recognizes unconditional rights to consideration separately as a receivable. Contract assets and receivables are evaluated at each reporting period to determine whether there is any objective evidence that they are impaired.

II. Revenue from Other Sources

Merchant Revenue

Revenues from non-contracted capacity (i.e., merchant) include energy payments, at market price, for each MWh produced and are recognized upon delivery.

Lease Revenue

In certain situations, a long-term electricity or thermal sales contract may contain, or be considered, a lease. Revenues associated with non-lease elements are recognized as goods or services revenues as outlined above. Where the terms and conditions of the contract result in the customer assuming the principal risks and rewards of ownership of the underlying asset, the contractual arrangement is considered a finance lease, which results in the recognition of finance lease income. Where the Company retains the principal risks and rewards, the contractual arrangement is an operating lease. Rental income, including contingent rents where applicable, is recognized over the term of the contract.

Revenue from Derivatives

Commodity risk management activities involve the use of derivatives such as physical and financial swaps, forward sales contracts, futures contracts and options, which are used to earn revenues and to gain market information. The Company also enters into contracts for differences and Virtual Power Purchase Agreements ("VPPA"). Contracts for differences are financial contracts whereby the Company receives a fixed price per MWh and pays the prevailing real-time energy market price per MWh. A VPPA is whereby the Company receives the difference between the fixed contract price per MWh and the settled market price. These arrangements meet the definition of a derivative and judgment is applied to determine if the contract meets the "own use" exemption or if derivative treatment is required.

These derivatives are accounted for using fair value accounting. The initial recognition and subsequent changes in fair value affect reported net earnings in the period the change occurs and are presented on a net basis in revenue. The fair values of instruments that remain open at the end of the reporting period represent unrealized gains or losses and are presented on the Consolidated Statements of Financial Position as risk management assets or liabilities. Some of the derivatives used by the Company in trading activities are not traded on an active exchange or have terms that extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using internal valuation techniques or models.

B. Financial Instruments and Hedges

I. Financial Instruments

Classification and Measurement

IFRS 9 introduced the requirement to classify and measure financial assets based on their contractual cash flow characteristics and the Company's business model for the financial asset. All financial assets and financial liabilities, including derivatives, are recognized at fair value on the Consolidated Statements of Financial Position when the Company becomes party to the contractual provisions of a financial instrument or non-financial derivative contract. Financial assets must be classified and measured at either amortized cost, at fair value through profit or loss ("FVTPL"), or at fair value through other comprehensive income (loss) ("FVTOCI").

Financial assets with contractual cash flows arising on specified dates, consisting solely of principal and interest and that are held within a business model whose objective is to collect the contractual cash flows, are subsequently measured at amortized cost. Financial assets measured at FVTOCI are those that have contractual cash flows, arising on specific dates, consisting solely of principal and interest and that are held within a business model whose objective is to collect the contractual cash flows and to sell the financial asset and investments in equity instruments. All other financial assets are subsequently measured at FVTPL.

Financial liabilities are classified as FVTPL when the financial liability is held for trading. All other financial liabilities are subsequently measured at amortized cost.

Funds received under tax equity investment arrangements are classified as long-term debt. These arrangements are used in the US where project investors acquire an equity investment in the project entity and in return for their investment, are allocated substantially all of the earnings, cash flows and tax benefits (such as production tax credits, investment tax credits, accelerated tax depreciation, as applicable) until they have achieved the agreed upon target rate of return. Once achieved, the arrangements flip, with the Company then receiving the majority of earnings, cash flows and tax benefits. At that time, the tax equity investor's investment is subsequently considered residual equity ownership with distributions classified as non-controlling interest. In applying the effective interest method to tax equity financings, the Company has made an accounting policy choice to recognize the impacts of the tax attributes in net interest expense.

The Company enters into a variety of derivative financial instruments to manage its exposure to commodity price risk, interest rate risk and foreign currency exchange risk, including fixed price financial swaps, long-term physical power sale contracts, foreign exchange forward contracts and designating foreign currency debt as a hedge of net investments in foreign operations.

Derivatives are initially recognized at fair value at the date the derivative contracts are entered into and are subsequently remeasured to their fair value at the end of each reporting period. The resulting gain or loss is recognized in net earnings immediately, unless the derivative is designated and effective as a hedging instrument, in which case the timing of the recognition in net earnings is dependent on the nature of the hedging relationship.

Derivatives embedded in non-derivative host contracts that are not financial assets within the scope of IFRS 9 (e.g., financial liabilities) are treated as separate derivatives when they meet the definition of a derivative, their risks and characteristics are not closely related to those of the host contracts and the host contracts are not measured at FVTPL. Derivatives embedded in hybrid contracts that contain financial asset hosts within the scope of IFRS 9 are not separated and the entire contract is measured at either FVTPL or amortized cost, as appropriate.

Financial assets are derecognized when the contractual rights to receive cash flows expire. Financial liabilities are derecognized when the obligation is discharged, cancelled or expired.

Financial assets are also derecognized when the Company has transferred its rights to receive cash flows from the asset or has assumed an obligation to pay the received cash flows to a third party under a "pass-through" arrangement and either transferred substantially all the risks and rewards of the asset, or transferred control of the asset. TransAlta will continue to recognize the asset and any associated liability if TransAlta retains substantially all of the risks and rewards of the asset, or retains control of the asset. Continuing involvement that takes the form of a guarantee over the transferred asset is measured at the lower of the original carrying amount of the asset and the maximum amount of consideration that TransAlta could be required to repay.

Financial assets and financial liabilities are offset and the net amount is reported in the Consolidated Statements of Financial Position if there is a currently enforceable legal right to offset the recognized amounts and there is an intention to settle on a net basis or to realize the assets and settle the liabilities simultaneously.

Transaction costs are expensed as incurred for financial instruments classified or designated as FVTPL. For other financial instruments, such as debt instruments, transaction costs are recognized as part of the carrying amount of the financial instrument. The Company uses the effective interest method of amortization for any transaction costs or fees, premiums or discounts earned or incurred for financial instruments measured at amortized cost.

Impairment of Financial Assets

TransAlta recognizes an allowance for expected credit losses for financial assets measured at amortized cost as well as certain other instruments. The loss allowance for a financial asset is measured at an amount equal to the lifetime expected credit loss if its credit risk has increased significantly since initial recognition or if the financial asset is a purchased or originated credit-impaired financial asset. If the credit risk on a financial asset has not increased significantly since initial recognition, its loss allowance is measured at an amount equal to the 12-month expected credit loss.

For trade receivables, lease receivables and contract assets recognized under IFRS 15, TransAlta applies a simplified approach for measuring the loss allowance. Therefore, the Company does not track changes in credit risk but instead recognizes a loss allowance at an amount equal to the lifetime expected credit losses at each reporting date.

The assessment of the expected credit loss is based on historical data and adjusted by forward-looking information. Forward-looking information utilized includes third-party default rates over time, dependent on credit ratings.

II. Hedges

Where hedge accounting can be applied and the Company chooses to seek hedge accounting treatment, a hedge relationship is designated as a fair value hedge, a cash flow hedge or a hedge of foreign currency exposures of a net investment in a foreign operation.

A relationship qualifies for hedge accounting if, at inception, it is formally designated and documented as a hedge and the hedging instrument and the hedged item have values that generally move in opposite direction because of the hedged risk. The documentation includes identification of the hedging instrument and hedged item or transaction, the nature of the risk being hedged, the Company's risk management objectives and strategy for undertaking the hedge and how hedge effectiveness will be assessed. The process of hedge accounting includes linking derivatives to specific recognized assets and liabilities or to specific firm commitments or highly probable anticipated transactions.

The Company formally assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives used are highly effective in offsetting changes in fair values or cash flows of hedged items. If hedge criteria are not met or the Company does not apply hedge accounting, the derivative is recognized at fair value on the Consolidated Statements of Financial Position, with subsequent changes in fair value recorded in net earnings in the period of change.

Fair Value Hedges

In a fair value hedging relationship, the carrying amount of the hedged item is adjusted for changes in fair value attributable to the hedged risk, with the changes being recognized in net earnings. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging derivative, which is also recorded in net earnings.

For fair value hedges relating to items carried at amortized cost, any adjustment to carrying value is amortized through profit or loss over the remaining term of the hedge using the effective interest rate ("EIR") method. The EIR amortization may begin as soon as an adjustment exists and no later than when the hedged item ceases to be adjusted for changes in its fair value attributable to the risk being hedged.

If the hedged item is derecognized, the unamortized fair value is recognized immediately in profit or loss.

Cash Flow Hedges

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive income (loss) ("OCI") while any ineffective portion is recognized in net earnings. The cash flow hedge reserve is adjusted to the lower of the cumulative gain or loss on the hedging instrument and the cumulative change in fair value of the hedged item.

If cash flow hedge accounting is discontinued, the amounts previously recognized in accumulated other comprehensive income (loss) ("AOCI") must remain in AOCI if the hedged future cash flows are still expected to occur. Otherwise, the amount will be immediately reclassified to net earnings as a reclassification adjustment. After discontinuation, once the hedged cash flow occurs, any amount remaining in AOCI must be accounted for depending on the nature of the underlying transaction.

Hedges of Foreign Currency Exposures of a Net Investment in a Foreign Operation

In hedging of a foreign currency exposure of a net investment in a foreign operation, the effective portion of foreign exchange gains and losses on the hedging instrument is recognized in OCI and the ineffective portion is recognized in net earnings. The related fair values are recorded in risk management assets or liabilities, as appropriate. The amounts previously recognized in AOCI are recognized in net earnings when there is a reduction in the hedged net investment as a result of a disposal, partial disposal or loss of control.

C. Cash and Cash Equivalents

Cash and cash equivalents comprises cash and highly liquid investments with original maturities of three months or less.

D. Inventory

I. Fuel

The Company's inventory balance is composed of coal and natural gas used as fuel, which is measured at the lower of weighted average cost and net realizable value. The cost of natural gas and purchased coal inventory includes all applicable expenditures and charges incurred in bringing the inventory to its existing condition and location.

II. Energy Marketing

Commodity inventories held in the Energy Marketing segment for trading purposes are measured at fair value less costs to sell. Changes in fair value less costs to sell are recognized in net earnings in the period of change.

III. Parts, Materials and Supplies

Parts, materials and supplies are recorded at the lower of cost and measured at moving average costs and net realizable value.

IV. Emission Credits and Allowances

Emission credits and allowances are recorded as inventory at cost. Those purchased for use by the Company are recorded at cost and are carried at the lower of weighted average cost and net realizable value. For emission credits that are not ordinarily interchangeable, the Company records the credits using the specific identification method. Credits granted to, or internally generated by, TransAlta are recorded at nil. Emission liabilities are recorded at the estimated compliance cost required by the Company to settle its obligation in excess of government-established caps and targets. Compliance costs that are recoverable under the terms of the contracts with third parties are recognized as Revenue from Contracts with Customers.

Emission credits and allowances that are held for trading and that meet the definition of a derivative are accounted for using the fair value method of accounting. Emission credits and allowances that do not satisfy the criteria of a derivative are accounted for using the accrual method.

E. Property, Plant and Equipment

The Company's investment in property, plant and equipment ("PP&E") is initially measured at the original cost of each component at the time of construction, purchase or acquisition. A component is a tangible portion of an asset that can be separately identified and depreciated over its own expected useful life and is expected to provide a benefit for a period in excess of one year. Original cost includes items such as materials, labour, borrowing costs and other directly attributable costs, including the initial estimate of the cost of decommissioning and restoration. Costs are recognized as PP&E if it is probable that future economic benefits will be realized and the cost of the item can be measured reliably. The cost of major spare parts is capitalized and classified as PP&E, as these items can only be used in connection with an item of PP&E.

Planned maintenance is performed at regular intervals. Planned major maintenance includes inspection, repair and maintenance of existing components and the replacement of existing components. Costs incurred for planned major maintenance activities are capitalized in the period maintenance activities occur and are amortized on a straight-line basis over the term until the next major maintenance event. Expenditures incurred for the replacement of components during major maintenance are capitalized and amortized over the estimated useful life of such components.

The cost of routine repairs and maintenance and the replacement of minor parts is charged to net earnings as incurred. Subsequent to initial recognition and measurement at cost, all classes of PP&E continue to be measured using the cost model and are reported at cost less accumulated depreciation and impairment losses, if any.

An item of PP&E or a component is derecognized upon disposal or when no future economic benefits are expected from its use or disposal. Any gain or loss arising on derecognition is included in net earnings when the asset is derecognized. The estimate of the useful life of each component of PP&E is based on current facts and past experience and takes into consideration existing long-term sales agreements and contracts, current and forecasted demand and the potential for technological obsolescence. The useful life is used to estimate the rate at which the component of PP&E is depreciated. PP&E assets are subject to depreciation when the asset is considered to be available for use, which is typically upon commencement of commercial operations. Insurance spares that are designated as critical for uninterrupted operation in a particular facility are depreciated over the life of that facility, even if the item is not in service. Capital spares begin to be depreciated when the item is put into service. Each significant component of an item of PP&E is depreciated to its residual value over its estimated useful life, generally using straight-line or unit-of-production methods. Estimated useful lives, residual values and depreciation methods are reviewed annually and are subject to revision based on new or additional information. The effect of a change in useful life, residual value or depreciation method is accounted for prospectively.

Estimated remaining useful lives of the components of depreciable assets, categorized by asset class, are as follows:

Hydro generation	1-49 years
Wind and Solar generation	1-30 years
Gas generation	1-34 years
Energy Transition	1-9 years
Capital spares and other	1-49 years

TransAlta capitalizes borrowing costs on capital invested in projects under construction. Upon commencement of commercial operations, capitalized borrowing costs, as a portion of the total cost of the asset, are depreciated over the estimated useful life of the related asset.

F. Intangible Assets

Intangible assets acquired in a business combination are recognized separately from goodwill at their fair value at the date of acquisition. Intangible assets acquired separately are recognized at cost. Internally generated intangible assets arising from development projects are recognized when certain criteria related to the feasibility of internal use or sale and probable future economic benefits of the intangible asset, are demonstrated.

Intangible assets are initially recognized at cost, which is composed of all directly attributable costs necessary to create, produce and prepare the intangible asset to be capable of operating in the manner intended by management.

Subsequent to initial recognition, intangible assets continue to be measured using the cost model and are reported at cost less accumulated amortization and impairment losses, if any. Amortization is included in depreciation and amortization in the Consolidated Statements of Earnings (Loss).

Amortization commences when the intangible asset is available for use and is computed on a straight-line basis over the intangible asset's estimated useful life. Estimated useful lives of intangible assets may be determined, for example, with reference to the term of the related contract or licence agreement. The estimated useful lives and amortization methods are reviewed annually with the effect of any changes being accounted for prospectively.

Intangible assets consist of power sale contracts with fixed prices higher than market prices at the date of acquisition, software and intangibles under development. Estimated remaining useful lives of intangible assets are as follows:

Software	1-7 years
Power sale contracts	1-18 years

G. Impairment of Tangible and Intangible Assets Excluding Goodwill

At the end of each reporting period, the Company assesses whether there is any indication that PP&E and finite life intangible assets are impaired.

Factors that could indicate that an impairment exists include: significant underperformance relative to historical or projected operating results; significant changes in the manner in which an asset is used, or in the Company's overall business strategy; or significant negative industry or economic trends. In some cases, these events are clear. However, in many cases, a clearly identifiable event indicating possible impairment does not occur. Instead, a series of individually insignificant events occur over a period of time leading to an indication that an asset may be impaired. This can be further complicated in situations where the Company is not the operator of the facility. Events can occur in these situations that may not be known until a date subsequent to their occurrence.

The Company's operations, the market and business environment are routinely monitored and judgments and assessments are made to determine whether an event has occurred that indicates a possible impairment. If such an event has occurred, an estimate is made of the recoverable amount of the asset or cash-generating unit ("CGU") to which the asset belongs. Recoverable amount is the higher of an asset's fair value less costs of disposal and its value in use. Fair value is the price that would be received to sell an asset in an orderly transaction between market participants at the measurement date. In determining fair value, recent market transactions are taken into account. If no such transactions can be identified, an appropriate valuation model such as discounted cash flow is used. Value in use is the present value of the estimated future cash flows expected to be derived from the asset from its continued use and ultimate disposal by the Company. If the recoverable amount is less than the carrying amount of the asset or CGU, an asset impairment charge is recognized in net earnings and the asset's carrying amount is reduced to its recoverable amount.

At each reporting date, an assessment is made whether there is any indication that an impairment charge previously recognized may no longer exist or may have decreased. If such indication exists, the recoverable amount of the asset or CGU to which the asset belongs is estimated and, if there has been an increase in the recoverable amount, the impairment charge previously recognized is reversed. Where an impairment charge is subsequently reversed, the carrying amount of the asset is increased to the lesser of the revised estimate of its recoverable amount or the carrying amount that would have been determined (net of depreciation) had no impairment charge been recognized previously. A reversal of an impairment charge is recognized in net earnings.

H. Goodwill

Goodwill arising in a business combination is recognized as an asset at the date control is acquired. Goodwill is measured as the cost of an acquisition plus the amount of any non-controlling interest in the acquiree (if applicable) less the fair value of the related identifiable assets acquired and liabilities assumed.

Goodwill is not subject to amortization, but is tested for impairment at least annually, or more frequently, if an analysis of events and circumstances indicates that a possible impairment may exist. These events could include a significant change in financial position of the CGUs or groups of CGUs to which the goodwill relates or significant negative industry or economic trends. For impairment purposes, goodwill is allocated to each of the Company's CGUs or groups of CGUs that are expected to benefit from the synergies of the business combination in which the goodwill arose. Accordingly, the Company performs its test for impairment, where the recoverable amount of the CGUs or groups of CGUs to which the goodwill relates is compared to its carrying amount for each operating segment. If the recoverable amount is less than the carrying amount, an impairment charge is recognized in net earnings immediately, by first reducing the carrying amount of the goodwill and then by reducing the carrying amount of the other assets in the unit. An impairment charge recognized for goodwill is not reversed in subsequent periods.

I. Income Taxes

The Company uses the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and liabilities are recognized on the differences between the carrying amounts of assets and liabilities and their respective income tax basis (temporary differences). A deferred income tax asset may also be recognized for the benefit expected from unused tax credits and losses available for carryforward, to the extent that it is probable that future taxable earnings will be available against which the tax credits and losses can be applied. Deferred income tax assets and liabilities are measured based on income tax rates and tax laws that are enacted or substantively enacted by the end of the reporting period and that are expected to apply in the years in which temporary differences are expected to be realized or settled. Deferred income tax is charged or credited to net earnings, except when related to items charged or credited to either OCI or directly to equity. The carrying amount of deferred income tax assets is evaluated at the end of each reporting period and is reduced to the extent that it is no longer probable that sufficient taxable income will be available to allow all or part of the asset to be realized. Unrecognized deferred tax assets are reassessed at each reporting date and are recognized to the extent that it has become probable that future taxable income will allow the deferred income tax asset to be recovered.

Deferred income tax liabilities are recognized for taxable temporary differences arising on investments in subsidiaries, except where the Company is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future.

Cash taxes paid disclosed on the Consolidated Statements of Cash Flows includes income taxes and taxes paid related to the Part VI.1 tax in Canada for the period.

J. Employee Future Benefits

The Company has defined benefit pension and other post-employment benefit plans. The current service cost of providing benefits under the defined benefit plans is determined using the projected unit credit method prorated based on service. The net interest cost is determined by applying the discount rate to the net defined benefit liability. The discount rate used to determine the present value of the defined benefit obligation and the net interest cost, is determined by reference to market yields at the end of the reporting period on high-quality corporate bonds with terms and currencies that match the estimated terms and currencies of the benefit obligations. Remeasurements, which include actuarial gains and losses and the return on plan assets (excluding net interest), are recognized through OCI in the period in which they occur. Actuarial gains and losses arise from experience adjustments and changes in actuarial assumptions. Remeasurements are not reclassified to profit or loss, from OCI, in subsequent periods.

Gains or losses arising from either a curtailment or settlement of a defined benefit plan are recognized when the curtailment or settlement occurs. When the restructuring of a benefit plan gives rise to a curtailment and a settlement of obligations, the curtailment is accounted for prior to the settlement.

In determining whether statutory minimum funding requirements of the Company's defined benefit pension plans give rise to recording an additional liability, letters of credit provided by the Company as security are considered to alleviate the funding requirements. No additional liability results in these circumstances.

Contributions payable under defined contribution pension plans are recognized as a liability and an expense in the period in which the services are rendered.

K. Provisions

Provisions are recognized when the Company has a present obligation (legal or constructive) as a result of a past event, it is probable that the Company will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. A legal obligation can arise through a contract, legislation or other operation of law. A constructive obligation arises from an entity's actions whereby through an established pattern of past practice, published policies or a sufficiently specific current statement, the entity has indicated it will accept certain responsibilities and has thus created a valid expectation that it will discharge those responsibilities. The amount recognized as a provision is the best estimate, remeasured at each period-end, of the expenditures required to settle the present obligation, considering the risks and uncertainties associated with the obligation. Where expenditures are expected to be incurred in the future, the obligation is measured at its present value using a current market-based, risk-adjusted interest rate.

The Company records a decommissioning and restoration provision for all generating facilities and mine sites for which it is legally or constructively required to remove the facilities at the end of their useful lives and restore the plant or mine sites. For some hydro facilities, the Company is required to remove the generating equipment, but is not required to remove the structures.

Initial decommissioning provisions are recognized at their present value when incurred. Each reporting date, the Company determines the present value of the provision using the current discount rates that reflect the time value of money and associated risks. The Company recognizes the initial decommissioning and restoration provisions, as well as changes resulting from revisions to cost estimates and period-end revisions to the market-based, risk-adjusted discount rate, as a cost of the related PP&E (see Note 2(E)) to the extent the related PP&E asset is still in use. Where the related PP&E asset has reached the end of its useful life, changes in the decommissioning and restoration provision are recognized in net earnings. Where the Company expects to receive reimbursement from a third party for a portion of future decommissioning costs, the reimbursement is recognized as a separate asset when it is virtually certain that the reimbursement will be received.

Changes in other provisions resulting from revisions to estimates of expenditures required to settle the obligation or period-end revisions to the market-based, risk-adjusted discount rate are recognized in net earnings.

The accretion of the net present value discount for both the decommissioning and restoration provision and other provisions are charged to net earnings each period and is included in net interest expense.

L. Leases

Under IFRS 16, a contract contains a lease when the customer obtains the right to control the use of an identified asset for a period of time in exchange for consideration.

I. Lessee

The Company enters into lease arrangements with respect to land, building and office space, vehicles and site machinery and equipment. For all contracts that meet the definition of a lease under IFRS 16 in which the Company is the lessee and which are not exempt as short-term or low-value leases, the Company:

- Recognizes right-of-use assets and lease liabilities in the Consolidated Statements of Financial Position;
- Recognizes depreciation of the right-of-use assets and interest expense on lease liabilities in the Consolidated Statements of Earnings (Loss); and
- Recognizes the principal repayments on lease liabilities as financing activities and interest payments on lease liabilities as operating activities in the Consolidated Statements of Cash Flows.

For short-term and low-value leases, the Company recognizes the lease payments as operating expenses.

Variable lease payments that do not depend on an index or a rate are not included in the measurement of the lease liability and the right-of-use asset and are recognized as an expense in the period in which the event or condition that triggers the payments occurs.

Right-of-use assets are initially measured at an amount equal to the lease liability and adjusted for any payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset, or to restore the underlying asset or the site on which it is located, less any lease incentives received.

Lease liabilities are initially measured at the present value of the lease payments that are not paid at commencement and discounted using the Company's incremental borrowing rate or the rate implicit in the lease. The lease liability is remeasured when there is a change in future lease payments arising from a change in an index or rate, or if there is a change in the Company's estimate or assessment of whether it will exercise an extension, termination or purchase option. A corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero.

The lease term includes periods covered by an option to extend if the Company is reasonably certain to exercise that option and periods covered by an option to terminate if the Company is reasonably certain not to exercise that option.

Right-of-use assets are depreciated over the shorter period of either the lease term or the useful life of the underlying asset. If a lease transfers ownership of the underlying asset or the cost of the right-of-use asset reflects that the Company expects to exercise the purchase option, the related right-of-use asset is depreciated over the useful life of the underlying asset.

The Company has elected to apply the practical expedient that permits a lessee not to separate non-lease components and instead account for any lease and associated non-lease components as a single arrangement.

II. Lessor

Power Purchase Agreements ("PPAs") and other long-term contracts may contain, or may be considered, leases where the fulfilment of the arrangement is dependent on the use of a specific asset (e.g., a generating unit) and the arrangement conveys to the customer the right to control the use of that asset.

Where the Company determines that the contractual provisions of a contract contain, or are, a lease and result in the customer assuming the principal risks and rewards of ownership of the asset, the arrangement is a finance lease. Assets subject to finance leases are not reflected as PP&E and the net investment in the lease, represented by the present value of the amounts due from the lessee, is recorded in the Consolidated Statements of Financial Position as a financial asset, classified as a finance lease receivable. The payments considered to be part of the leasing arrangement are apportioned between a reduction in the lease receivable and finance lease income. The finance lease income element of the payments is recognized using a method that results in a constant rate of return on the net investment in each period and is reflected in finance lease income on the Consolidated Statements of Earnings (Loss).

Where the Company determines that the contractual provisions of a contract contain, or are, a lease and result in the Company retaining the principal risks and rewards of ownership of the asset, the arrangement is an operating lease. For operating leases, the asset is, or continues to be, capitalized as PP&E and depreciated over its useful life.

M. Non-Controlling Interests

Non-controlling interests arise from business combinations in which the Company acquires less than a 100 per cent interest. Non-controlling interests are initially measured at either fair value or at the non-controlling interest's proportionate share of the acquiree's identifiable net assets. The Company determines on a transaction-by-transaction basis for which the measurement method is used. Non-controlling interests also arise from other contractual arrangements between the Company and other parties, whereby the other party has acquired an equity interest in a subsidiary and the Company retains control.

Subsequent to acquisition, the carrying amount of non-controlling interests is increased or decreased by the non-controlling interest's share of subsequent changes in equity and payments to the non-controlling interest. Total comprehensive income (loss) is attributed to the non-controlling interests even if this results in the non-controlling interests having a negative balance.

When the proportion of the equity held by non-controlling interests changes, the carrying amounts of the controlling and non-controlling interests are adjusted to reflect the changes in their relative interests in the subsidiary. Any difference between the amount by which the non-controlling interests are adjusted and the fair value of the consideration paid or received, is recognized directly in equity and attributed to shareholders.

N. Joint Arrangements

A joint arrangement is a contractual arrangement that establishes the terms by which two or more parties agree to undertake and jointly control an economic activity. The Company's joint arrangements are generally classified as two types: joint operations and joint ventures.

A joint operation arises when the parties that have joint control have rights to the assets and obligations for the liabilities relating to the arrangement. Generally, each party takes a share of the output from the asset and each bears an agreed upon share of the costs incurred in respect of the joint operation. The Company reports its interests in joint operations in its Consolidated Financial Statements using the proportionate consolidation method by recognizing its share of the assets, liabilities, revenues and expenses in respect of its interest in the joint operation.

In a joint venture, the venturers do not have rights to individual assets or obligations of the venture. Rather, each venturer has rights to the net assets of the arrangement. The Company reports its interests in joint ventures using the equity method. Under the equity method, the investment is initially recognized at cost and the carrying amount is increased or decreased to recognize the Company's share of the joint venture's net earnings or loss after the date of acquisition. The impact of transactions between the Company and joint ventures is eliminated based on the Company's ownership interest. Distributions received from joint ventures reduce the carrying amount of the investment. Any excess of the cost of an acquisition less the fair value of the recognized identifiable assets, liabilities and contingent liabilities of an acquired joint venture is recognized as goodwill and is included in the carrying amount of the investment and is assessed for impairment as part of the investment.

Investments in joint ventures are evaluated for impairment at each reporting date by first assessing whether there is objective evidence that the investment is impaired. If such objective evidence is present, an impairment charge is recognized if the investment's recoverable amount is less than its carrying amount. The investment's recoverable amount is determined as the higher of value in use and fair value less costs of disposal.

O. Business Combinations

Transactions in which the acquisition constitutes a business are accounted for using the acquisition method. Identifiable assets acquired and liabilities assumed are measured at their acquisition date fair values. A business consists of inputs and processes applied to those inputs that have the ability to contribute to the creation of outputs. Goodwill is measured as the excess of the fair value of consideration transferred less the fair value of the identifiable assets acquired and liabilities assumed. Acquisition-related costs to effect the business combination, with the exception of costs to issue debt or equity securities, are recognized in net earnings as incurred.

The optional fair value concentration test is applied on a transaction-by-transaction basis to permit a simplified assessment of whether an acquired set of activities and assets are not a business. Where substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or group of similar identifiable assets, the Company may elect to treat the acquisition as an asset acquisition and not as a business combination.

P. Significant Accounting Judgments and Key Sources of Estimation Uncertainty

The preparation of financial statements requires management to make judgments, estimates and assumptions that could affect the reported amounts of assets, liabilities, revenues, expenses and disclosures of contingent assets and liabilities during the period. These estimates are subject to uncertainty. Actual results could differ from those estimates due to factors such as fluctuations in interest rates, foreign exchange rates, inflation and commodity prices and changes in economic conditions, legislation and regulations.

In the process of applying the Company's accounting policies, management has to make judgments and estimates about matters that are highly uncertain at the time the estimate is made and that could significantly affect the amounts recognized in the Consolidated Financial Statements. Different estimates with respect to key variables used in the calculations, or changes to estimates, could potentially have a material impact on the Company's financial position or performance. The key judgments and sources of estimation uncertainty are described below:

I. Impairment of PP&E and Goodwill

Impairment exists when the carrying amount of an asset, CGU or group of CGUs to which goodwill relates exceeds its recoverable amount, which is the higher of its fair value less costs of disposal and its value in use. An assessment is made at each reporting date as to whether there is any indication that an impairment charge may exist or that a previously recognized impairment charge may no longer exist or may have decreased. In determining fair value less costs of disposal, information about third-party transactions for similar assets is used and if none is available, other valuation techniques, such as discounted cash flows, are used. Value in use is computed using the present value of management's best estimates of future cash flows based on the current use and present condition of the asset.

In estimating either fair value less costs of disposal or value in use using discounted cash flow methods, estimates and assumptions must be made about sales prices, cost of sales, production, fuel consumed, capital expenditures, retirement costs and other related cash inflows and outflows over the life of the facilities. In developing these assumptions, management uses estimates of contracted and future market prices based on expected market supply and demand in the region in which the plant operates, anticipated production levels, planned and unplanned outages, changes to regulations and transmission capacity or constraints for the remaining life of the facilities.

Discount rates are determined by employing a weighted average cost of capital methodology that is based on capital structure, cost of equity and cost of debt assumptions based on comparable companies with similar risk characteristics and market data as the asset, CGU or group of CGUs subject to the test. These estimates and assumptions are susceptible to change from period to period and actual results can and often do, differ from the estimates and can have either a positive or negative impact on the estimate of the impairment charge and may be material.

The impairment outcome can also be impacted by the determination of CGUs or groups of CGUs for asset and goodwill impairment testing. A CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets and goodwill is allocated to each CGU or group of CGUs that is expected to benefit from the synergies of the acquisition from which the goodwill arose. The allocation of goodwill is reassessed upon changes in the composition of segments, CGUs or groups of CGUs. In respect of determining CGUs, significant judgment is required to determine what constitutes independent cash flows between power plants that are connected to the same system. The Company evaluates the market design, transmission constraints and the contractual profile of each facility, as well as the Company's own commodity price risk management plans and practices, in order to inform this determination.

With regard to the allocation or reallocation of goodwill, significant judgment is required to evaluate synergies and their impacts. Minimum thresholds also exist with respect to segmentation and internal monitoring activities. The Company evaluates synergies with regard to opportunities from combined talent and technology, functional organization and future growth potential and considers its own performance measurement processes in making this determination. Information regarding significant judgments and estimates in respect of impairment during 2021 to 2023 is disclosed in Notes 7, 18 and 21.

II. Leases

In determining whether the Company's contracts contain, or are, leases, management must use judgment in assessing whether the contract provides the customer with the right to substantially all of the economic benefits from the use of the asset during the lease term and whether the customer obtains the right to direct the use of the asset during the lease term. For those agreements considered to contain, or be, leases, further judgment is required to determine the lease term by assessing whether termination or extension options are reasonably certain to be exercised. Judgment is also applied in identifying in-substance fixed payments (included) and variable payments that are based on usage or performance factors (excluded) and in identifying lease and non-lease components (services that the supplier performs) of contracts and in allocating contract payments to lease and non-lease components.

For leases where the Company is a lessor, judgment is required to determine if substantially all of the significant risks and rewards of ownership are transferred to the customer or remain with the Company to appropriately account for the agreement as either a finance or operating lease. These judgments can be significant and impact how the Company classifies amounts related to the arrangement as either PP&E or as a finance lease receivable on the Consolidated Statements of Financial Position and therefore the amount of certain items of revenue and expense is dependent upon such classifications. In 2023, a finance lease receivable was recognized as it was determined that the significant risks and rewards of ownership of the facilities were transferred to the customer. See Note 17.

III. Income Taxes

Preparation of the Consolidated Financial Statements involves determining an estimate of, or provision for, income taxes in each of the jurisdictions in which the Company operates. The process also involves making an estimate of income taxes currently payable and income taxes expected to be payable or recoverable in future periods, referred to as deferred income taxes. Deferred income taxes result from the effects of temporary differences due to items that are treated differently for tax and accounting purposes. The tax effects of these differences are reflected in the Consolidated Statements of Financial Position as deferred income tax assets and liabilities. An assessment must also be made to determine the likelihood that the Company's future taxable income will be sufficient to permit the recovery of deferred income tax assets. To the extent that such recovery is not probable, deferred income tax assets must be reduced. Management uses the Company's long-range forecasts as a basis for evaluation of recovery of deferred income tax assets. Management must exercise judgment in its assessment of continually changing tax interpretations, regulations and legislation to ensure deferred income tax assets and liabilities are complete and fairly presented. Differing assessments and applications than the Company's estimates could materially impact the amounts recognized for deferred income tax assets and liabilities. Information regarding the impacts of the Company's tax policies is disclosed in Note 11.

IV. Financial Instruments and Derivatives

The Company's financial instruments and derivatives are accounted for at fair value, with the initial and subsequent changes in fair value affecting earnings in the period the change occurs. The fair values of financial instruments and derivatives are classified within three levels, with Level III fair values determined using inputs for the asset or liability that are not readily observable. Transfers between levels of the fair value hierarchy are deemed to have occurred at the end of the reporting period in which the event or change in circumstances that caused the transfer occurred. These fair value levels are outlined and discussed in more detail in Note 14. Some of the Company's fair values are included in Level III because they are not traded on an active exchange or have terms that extend beyond the time period for which exchange-based quotes are available and require the use of internal valuation techniques or models to determine fair value.

The determination of the fair value of these contracts and derivative instruments can be complex and relies on judgments and estimates concerning future prices, volatility and liquidity, among other factors. These fair value estimates may not necessarily be indicative of the amounts that could be realized or settled and changes in these assumptions could affect the reported fair value of financial instruments. Fair values can fluctuate significantly and can be favourable or unfavourable depending on current market conditions. Judgment is also used in determining whether a highly probable forecasted transaction designated in a cash flow hedge is expected to occur based on the Company's estimates of pricing and production to allow the future transaction to be fulfilled.

When the Company enters into contracts to buy or sell non-financial items, such as certain commodities, and the contracts can be settled net in cash, the Company must use judgment to evaluate whether such contracts were entered into and continue to be held for the purposes of the receipt or delivery of the commodity in accordance with the Company's expected purchase, sale or usage requirements (i.e., normal purchase and sale). If this assertion cannot be supported, initially at contract inception and on an ongoing basis, the contracts must be accounted for as derivatives and measured at fair value, with changes in fair value recognized in net earnings. In supporting the normal purchase and sale assertion, the Company considers the nature of the contracts, the forecasted demand and supply requirements to which the contracts relate and its past practice of net settling other similar contracts, which may taint the normal purchase and sale assertion. The Company also enters into PPAs and contracts for differences and judgment is applied to determine if the contract meets the "own use" exemption or if derivative treatment is required.

V. Project Development Costs

Project development costs are recognized in operating expenses until construction of a facility or acquisition of an investment is likely to occur, there is reason to believe that future costs are recoverable and that efforts will result in future value to the Company, at which time the costs incurred subsequently are included in PP&E or other assets. The appropriateness of capitalization of these costs is evaluated each reporting period and amounts capitalized for projects no longer probable of occurring or when there is uncertainty of timing of when the projects will proceed are charged to net earnings. Management is required to use judgment to determine if there is reason to believe that future costs are recoverable and that efforts will result in future value to the Company when determining the amount to be capitalized. Information regarding project development costs is disclosed in Note 22 and information on the write-off of project development costs is disclosed in Note 7.

VI. Provisions for Decommissioning and Restoration Activities

TransAlta recognizes provisions for decommissioning and restoration obligations as outlined in Note 2(K). Initial decommissioning provisions and subsequent changes thereto are determined using the Company's best estimate of the required cash expenditures, adjusted to reflect the risks and uncertainties inherent in the timing and amount of settlement. The estimated cash expenditures are present valued using a current, risk-adjusted, market-based, pre-tax discount rate. A change in estimated cash flows, market interest rates or timing could have a material impact on the carrying amount of the provision. Information regarding significant judgments and estimates made during 2021 to 2023 in respect of decommissioning and restoration provisions is disclosed in Notes 7, 18 and 23.

VII. Useful Life of PP&E

Each significant component of an item of PP&E is depreciated over its estimated useful life. Estimated useful lives are determined based on current facts and past experience and take into consideration the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecasted demand, the potential for technological obsolescence and regulations. The useful lives of PP&E are reviewed at least annually to ensure they continue to be appropriate. Information on changes in useful lives of facilities is disclosed in Note 18.

VIII. Employee Future Benefits

The Company provides pension and other post-employment benefits, such as health and dental benefits, to employees. The cost of providing these benefits is dependent upon many factors, including actual plan experience and estimates and assumptions about future experience.

The liability for pension and post-employment benefits and associated costs included in annual compensation expenses are impacted by estimates related to:

- Employee demographics, including age, compensation levels, employment periods, the level of contributions made to the plans and earnings on plan assets;
- The effects of changes to the provisions of the plans; and
- Changes in key actuarial assumptions, including rates of compensation and health-care cost increases and discount rates.

Due to the complexity of the valuation of pension and post-employment benefits, a change in the estimate of any one of these factors could have a material effect on the carrying amount of the liability for pension and other post-employment benefits or the related expense. These assumptions are reviewed annually to ensure they continue to be appropriate. Disclosures on employee future benefits are disclosed in Note 31.

IX. Other Provisions

Where necessary, the Company recognizes provisions arising from ongoing business activities, such as interpretation and application of contract terms, ongoing litigation and force majeure claims. These provisions and subsequent changes thereto, are determined using the Company's best estimate of the outcome of the underlying event and can also be impacted by determinations made by third parties, in compliance with contractual requirements. The actual amount of the provisions that may be required could differ materially from the amount recognized. More information is disclosed in Notes 8 and 23 with respect to other provisions.

X. Revenue from Contracts with Customers

Where contracts contain multiple promises for goods or services, management exercises judgment in determining whether goods or services constitute distinct goods or services or a series of distinct goods that are substantially the same and that have the same pattern of transfer to the customer. The determination of a performance obligation affects whether the transaction price is recognized at a point in time or over time. Management considers both the mechanics of the contract and the economic and operating environment of the contract in determining whether the goods or services in a contract are distinct.

In determining the transaction price and estimates of variable consideration, management considers the past history of customer usage in estimating the goods and services to be provided to the customer. The Company also considers the historical production levels and operating conditions for its variable generating assets. The Company's contracts generally outline a specific amount to be invoiced to a customer associated with each performance obligation in the contract. Where contracts do not specify amounts for individual performance obligations, the Company estimates the amount of the transaction price to allocate to individual performance obligations based on their stand-alone selling price, which is primarily estimated based on the amounts that would be charged to customers under similar market conditions.

The satisfaction of performance obligations requires management to make judgments as to when control of the underlying good or service transfers to the customer. Determining when a performance obligation is satisfied affects the timing of revenue recognition. Management considers both customer acceptance of the good or service and the impact of laws and regulations such as certification requirements, to determine when this transfer occurs.

When contracts are modified, management must exercise judgment to determine, depending upon the facts and circumstances of the changes to the contract, whether the modification is accounted for as a new contract or as part of the existing contract. If it is required to be accounted for as part of the existing contract the transaction price can be affected and adjustments to previously recognized revenue can occur, or the impacts can be reflected prospectively from the modification date.

Management also applies judgment in determining whether the invoice practical expedient permits recognition of revenue at the invoiced amount if that invoiced amount corresponds directly with the entity's performance to date.

XI. Classification of Joint Arrangements

Upon entering into a joint arrangement, the Company must classify it as either a joint operation or joint venture, and this classification affects the accounting for the joint arrangement. In making this classification, the Company exercises judgment in evaluating the terms and conditions of the arrangement to determine whether the parties have rights to the assets and obligations or rights to the net assets. Factors such as the legal structure, contractual arrangements and other facts and circumstances, such as where the purpose of the arrangement is primarily for the provision of the output to the parties and when the parties are substantially the only source of cash flows for the arrangement, must be evaluated to understand the rights of the parties to the arrangement.

XII. Significant Influence

Upon entering into an investment, the Company must classify it as either an investment in an associate or an investment under IFRS 9. In making this classification, the Company exercises judgment in evaluating whether the Company has significant influence over the investee. Significant influence is the power to participate in the financial and operating policy decisions of the investee, but is not control or joint control over those policies. If the Company holds 20 per cent or more of the voting rights in the investee, it is presumed that the entity has significant influence, unless it can be clearly demonstrated that this is not the case. Other factors such as representation on the Board, participation in policy-making processes, material transactions between the Company and investee, interchange of managerial personnel or providing essential technical information are considered when assessing if the Company has significant influence over an investee.

XIII. Change in Estimates

During the year ended Dec. 31, 2023, there were changes in estimates relating to asset impairment charges (reversals) (Note 7), useful lives (Note 18), decommissioning and other provisions (Note 23) and defined benefit obligation (Note 26). During the year ended Dec. 31, 2022, there were changes in estimates relating to asset impairment charges (reversals) (Note 7), asset useful lives and depreciation (Note 18), decommissioning and other provisions (Note 23) and defined benefit obligation (Note 26).

3. Accounting Changes

A. Current Accounting Changes

Amendments to IAS 12 Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction

On May 7, 2021, the International Accounting Standards Board ("IASB") issued Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction, which amends IAS 12 Income Taxes. The amendments clarify that the initial recognition exemption under IAS 12 does not apply to transactions such as leases and decommissioning obligations. These transactions give rise to equal and offsetting temporary differences in which deferred tax should be recognized.

The amendments are effective for annual periods beginning on or after Jan. 1, 2023, and were adopted by the Company on that date. The Company's accounting aligns with the amendment and no financial impact arose upon adoption.

Amendments to IAS 12 International Tax Reform — Pillar Two Model Rules

The Organization for Economic Co-operation and Development (OECD) published Pillar Two model rules in December 2021 to ensure that large multinational companies would be subject to a minimum 15 per cent tax rate. In May 2023, the IASB issued amendments to IAS 12 Income Taxes to provide companies with immediate temporary relief from accounting for deferred taxes arising from the OECD international tax reform. The amendments clarify that IAS 12 applies to income taxes arising from tax law enacted or substantively enacted to implement the Pillar Two model rules published by the OECD. Pillar Two legislation has not been enacted or substantively enacted in any jurisdiction in which the Company operates and therefore has not been reflected within our tax provisions at Dec. 31, 2023.

B. Future Accounting Changes

The Company closely monitors both new accounting standards and amendments to existing accounting standards issued by the IASB. The following standards have been issued but are not yet in effect.

Amendments to IAS 1 Non-current Liabilities with Covenants and Classification of Liabilities as Current or Non-current

In October 2022, the IASB issued Non-current Liabilities with Covenants, which amends IAS 1 Presentation of Financial Statements, to clarify how conditions with which an entity must comply within 12 months after the reporting period affect the classification of a liability. In January 2020, the IASB issued Classification of Liabilities as Current or Non-current, which amends IAS 1 Presentation of Financial Statements regarding the classification of liabilities as current or non-current, clarifying that contractual rights and conditions existing at the end of the reporting period are relevant in determining whether the Company has a right to defer settlement of a liability by at least 12 months.

Additionally, the IASB clarified that the classification of a liability is unaffected by the likelihood that an entity will exercise its deferral right. The amendments are effective for annual periods beginning on or after Jan. 1, 2024, and are to be applied retrospectively. On Jan. 1, 2024, the Company will re-classify the Exchangeable Securities from non-current liabilities to current liabilities as the conversion option can be exercised at any time after Jan. 1, 2025, although there is no obligation to deliver cash equivalent resources and the holder cannot call for repayment. This accounting is consistent with the amendment.

C. Comparative Figures

Certain comparative figures have been reclassified to conform to the current period's presentation. These reclassifications did not impact previously reported net earnings.

4. Business Acquisitions

TransAlta to Acquire Heartland Generation

On Nov. 2, 2023, the Company announced that it had entered into a definitive share purchase agreement (the "Agreement") with an affiliate of Energy Capital Partners, the parent of Heartland Generation Ltd. and Alberta Power (2000) Ltd. (collectively, "Heartland"), pursuant to which TransAlta will acquire Heartland and its entire business operations in Alberta and British Columbia. The purchase price for the acquisition is $390 million, subject to working capital and other adjustments, as well as the assumption of $268 million of debt, for a total cost of $658 million. The Company will finance the transaction using cash on hand and draws on its credit facilities. Closing of the transaction remains subject to regulatory approval.

Acquisition of TransAlta Renewables

On Oct. 5, 2023, the Company completed the acquisition of the outstanding common shares of TransAlta Renewables not already owned, directly or indirectly, by the Company. The consideration paid totalled $1.3 billion, comprising $800 million of cash and 46 million common shares of the Company valued at $514 million, based on an $11.06 closing price of the Company's shares on the Toronto Stock Exchange on Oct. 4, 2023.

Transaction costs of $11 million incurred to effect the acquisition, have been charged, net of income tax, against Common Shares ($4 million) and Deficit ($7 million) on closing of the acquisition.

Since the Company retained control of TransAlta Renewables, the acquisition was accounted for as an equity transaction. On closing of the transaction, Non-controlling Interests was reduced by $630 million and Accumulated Other Comprehensive Loss increased by $64 million to eliminate the balances previously attributed to non-controlling interest holders of TransAlta Renewables. The difference between consideration paid and these amounts was recognized in Deficit.

The Company's syndicated credit facilities were amended to effectively consolidate the TransAlta Renewables syndicated credit facility and non-committed demand facility into the TransAlta credit facilities. The cash drawings on the TransAlta Renewables' syndicated credit facility were repaid and the outstanding letters of credit were transferred to the TransAlta non-committed demand facility. The TransAlta Renewables' credit facilities were then terminated. This resulted in the TransAlta syndicated credit facility increasing by $700 million to approximately $2.0 billion. Refer to Note 24.

5. Revenue

A. Disaggregation of Revenue

The majority of the Company's revenues are derived from the sale of power, capacity and environmental attributes, leasing of power facilities and from asset optimization activities, which the Company disaggregates into the following groups for the purpose of determining how economic factors affect the recognition of revenue.

Year ended Dec. 31, 2023	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Revenues from contracts with customers							
Power and other	30	190	400	12	—	—	632
Environmental attributes(1)	14	26	—	—	—	—	40
Revenue from contracts with customers	44	216	400	12	—	—	672
Revenue from leases(2)	—	—	32	—	—	—	32
Revenue from derivatives and other trading activities(3)	44	(2)	(172)	251	220	—	341
Revenue from merchant sales	434	104	1,247	488	—	—	2,273
Other(4)	11	18	7	—	—	1	37
Total revenue	533	336	1,514	751	220	1	3,355
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	14	26	—	12	—	—	52
Over time	30	190	400	—	—	—	620
Total revenue from contracts with customers	44	216	400	12	—	—	672

(1) The environmental attributes represent environmental attribute sales not bundled with power and other sales.

(2) Total lease income from long-term contracts that meet the criteria of operating leases.

(3) Represents realized and unrealized gains or losses from hedging and derivative positions. Volatility and pricing in commodity markets can vary significantly from period to period and impact movements in derivative positions.

(4) Other revenue includes production tax credits related to US wind facilities and other miscellaneous revenues.

Year ended Dec. 31, 2022	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Revenues from contracts with customers							
Power and other	33	220	462	10	—	—	725
Environmental attributes[1]	1	50	—	—	—	—	51
Revenue from contracts with customers	34	270	462	10	—	—	776
Revenue from leases[2]	—	—	32	—	—	—	32
Revenue from derivatives and other trading activities[3]	—	(121)	(821)	243	160	(2)	(541)
Revenue from merchant sales	564	119	1,529	461	—	—	2,673
Other[4]	8	21	7	—	—	—	36
Total revenue	606	289	1,209	714	160	(2)	2,976
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	1	50	—	12	—	—	63
Over time	33	220	462	(2)	—	—	713
Total revenue from contracts with customers	34	270	462	10	—	—	776

(1) The environmental attributes represent environmental attribute sales not bundled with power and other sales.

(2) Total lease income from long-term contracts that meet the criteria of operating leases.

(3) Represents realized and unrealized gains or losses from hedging and derivative positions. Volatility and pricing in commodity markets can vary significantly from period to period and impact movements in derivative positions.

(4) Other revenue includes production tax credits related to US wind facilities and other miscellaneous revenues.

Year ended Dec. 31, 2021	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Revenues from contracts with customers							
Power and other	28	207	395	24	—	—	654
Environmental attributes[1]	—	28	—	—	—	—	28
Revenue from contracts with customers	28	235	395	24	—	—	682
Revenue from leases[2]	—	—	19	—	—	—	19
Revenue from derivatives and other trading activities[3]	—	(22)	(118)	138	211	4	213
Revenue from merchant sales	345	35	808	546	—	—	1,734
Other[4]	10	57	5	1	—	—	73
Total revenue	383	305	1,109	709	211	4	2,721
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	—	28	2	23	—	—	53
Over time	28	207	393	1	—	—	629
Total revenue from contracts with customers	28	235	395	24	—	—	682

(1) The environmental attributes represent environmental attribute sales not bundled with power and other sales.

(2) Total lease income from long-term contracts that meet the criteria of operating leases.

(3) Represents realized and unrealized gains or losses from hedging and derivative positions. Volatility and pricing in commodity markets can vary significantly from period to period and impact movements in derivative positions.

(4) Other revenue includes production tax credits related to US wind facilities and other miscellaneous revenues.

B. Performance Obligations

The performance obligations in the Company's contracts with its customers include the provision of electricity and steam capacity; the delivery of electricity, thermal energy and environmental attributes; the provision of operation and maintenance services and water management services; and the supply of byproducts from coal generation.

The aggregate amount of transaction prices allocated to remaining performance obligations (contract revenues that have not yet been recognized) as at Dec. 31, 2023, is approximately $2,700 million, with approximately $510 million expected to be recognized during the period 2024-2026; $505 million for the period of 2027-2029; $725 million for the period of 2030-2034; and $960 million for 2035 and thereafter.

These amounts exclude revenues related to contracts that qualify for the invoice practical expedient and future revenues that are related to constrained variable consideration. In many of the Company's contracts, elements of the transaction price are considered constrained, such as for variable revenues dependent upon future production volumes that are driven by customer or market demand or market prices that are subject to factors outside the Company's influence. As a result, the amounts of future revenues disclosed above represent only a portion of future revenues that are expected to be realized by the Company from its contractual portfolio.

6. Expenses by Nature

Fuel, Purchased Power and Operations, Maintenance and Administration ("OM&A")

Fuel and purchased power and OM&A expenses classified by nature are as follows:

	2023		2022		2021	
Year ended Dec. 31	Fuel and purchased power	OM&A	Fuel and purchased power	OM&A	Fuel and purchased power	OM&A
Gas fuel costs	**384**	**—**	578	—	306	—
Coal fuel costs[1]	**177**	**—**	146	—	164	—
Royalty, land lease, other direct costs	**25**	**—**	25	—	19	—
Purchased power	**474**	**—**	514	—	339	—
Mine depreciation[2]	**—**	**—**	—	—	190	—
Salaries and benefits	**—**	**254**	—	263	36	234
Other operating expenses[3]	**—**	**285**	—	258	—	277
Total	**1,060**	**539**	1,263	521	1,054	511

(1) Included in coal fuel costs for 2021 was $17 million related to the impairment of coal inventory.

(2) Included in mine depreciation for 2021 was $48 million related to mine depreciation that was initially recorded in the standard cost of coal inventory and then subsequently written down during 2021.

(3) Included in OM&A costs for 2023 was $14 million related to the write-down of parts and material inventory related to our natural-gas-fired facilities. Included in OM&A costs for 2021 was $28 million related to the write-down of parts and material inventory related to the Highvale mine and coal operations at our natural gas converted facilities.

7. Asset Impairment Charges (Reversals)

As part of the Company's monitoring controls, long-range forecasts are prepared for each CGU. The long-range forecast estimates are used to assess the significance of potential indicators of impairment and provide criteria to evaluate adverse changes in operations. The Company also considers the relationship between its market capitalization and its book value, among other factors, when reviewing for indicators of impairment. When indicators of impairment are present, the Company estimates a recoverable amount (the higher of value in use or fair value less costs of disposal) for the affected CGUs using discounted cash flow projections. The valuations are subject to measurement uncertainty from assumptions and inputs to the discount rates, power price forecasts, useful lives of the assets (extending to the last planned asset retirement in 2072) and long-range forecasts, which includes changes to production, fuel costs, operating costs and capital expenditures.

The Company recognized the following asset impairment charges (reversals):

Year ended Dec. 31	2023	2022	2021
Segments:			
Hydro	**(10)**	21	5
Wind and Solar	**(4)**	43	12
Gas		—	5
Energy Transition	**—**	—	540
Corporate	**—**	(2)	27
Changes in decommissioning and restoration provisions on retired assets(1)	**(34)**	(53)	32
Intangible asset impairment charges - coal rights	**—**	—	17
Project development costs	**—**	—	10
Asset impairment charges (reversals)	**(48)**	9	648

(1) Changes relate to changes in discount rates and cash flow revisions on retired assets in 2023 and 2022 and cash flow revisions on retired assets in 2021. Refer to Note 23 for further details.

Hydro

During 2023, internal valuations indicated the fair value less costs of disposal for two hydro facilities exceeded the carrying value due to a contract extension and changes in power price assumptions, which favourably impacted estimated future cash flows and resulted in a recoverability test. As a result of the recoverability test an impairment reversal of $10 million was recognized. The recoverable amounts of $70 million in total were estimated based on fair value less costs of disposal utilizing a discounted cash flow approach and are categorized as a Level III fair value measurement.

During 2022, the Company recorded net impairment charges of $21 million on four hydro facilities as a result of changes in key assumptions, that included significant increases in discount rates, changes in pricing and changes in estimated future cash flows. The recoverable amounts of $89 million in total for these four assets were estimated based on fair value less costs of disposal using a discounted cash flow approach and are categorized as a Level III fair value measurement.

Wind and Solar

During 2023, the Company recorded net impairment reversals of $4 million.

During the year, internal valuations indicated the fair value less costs of disposal of the assets exceeded the carrying value due to changes in power price assumptions for three wind facilities, which favourably impacted estimated future cash flows and resulted in impairment reversals of $17 million. The recoverable amounts of $540 million in total were estimated based on fair value less costs of disposal utilizing a discounted cash flow approach and are categorized as a Level III fair value measurement.

Also in 2023, two wind facilities were impaired primarily due to unfavourable power price assumptions and changes in estimated future cash flows, resulting in a $13 million impairment charge. The recoverable amounts of $130 million for these two assets were estimated based on fair value less costs of disposal utilizing a discounted cash flow approach and are categorized as a Level III fair value measurement.

During 2022, the Company recorded net impairment charges of $43 million on five wind facilities and one solar facility as a result of changes in key assumptions, that included significant increases in discount rates, changes in pricing and changes in estimated future cash flows. The recoverable amounts of $754 million for these six assets were estimated based on fair value less costs of disposal utilizing a discounted cash flow approach and categorized as a Level III fair value measurement.

During 2021, the Company recorded impairment charges of $10 million for a wind asset as a result of an increase in estimated decommissioning costs after the review of an engineering study commissioned for the wind sites. The recoverable amount of $65 million was estimated based on fair value less costs of disposal utilizing a discounted cash flow approach, using a discount rate of 5.0 per cent, and was categorized as a Level III fair value measurement.

Additionally, during 2021, the Company recognized impairment charges of $2 million related to the Kent Hills Wind LP tower failure. The Company's subsidiary, Kent Hills Wind LP, experienced a single tower failure at its 167 MW Kent Hills wind facility in Kent Hills, New Brunswick. The failure involved a collapsed tower located within the Kent Hills 2 site.

The calculation of fair value less costs of disposal for all of the above facilities is most sensitive to the following assumptions:

	Location of assets	Current year contract and merchant discount rates	Prior year contract and merchant discount rates
Wind and Solar	Canada	6.4 and 7.0 per cent	6.4 and 7.1 per cent
	US	6.9 and 7.5 per cent	6.5 and 7.7 per cent
Hydro	Canada	6.1 and 6.4 per cent	5.9 and 6.4 per cent

Energy Transition

During 2021, the Company recognized asset impairment charges in the Energy Transition segment as a result of the decision to suspend the Sundance Unit 5 repowering project ($191 million) and planned retirements of Keephills Unit 1, effective Dec. 31, 2021 ($94 million), and Sundance Unit 4, effective April 1, 2022 ($56 million). Keephills Unit 1 and Sundance Unit 4 impairment assessments were based on the estimated salvage values of these units, which were in excess of the expected economic benefits from these units. For the Sundance Unit 5 repowering project, the recoverable amount was determined based on estimated fair value less costs of disposal of selling the assets under construction and estimated salvage value for the balance of the costs. The fair value measurement for assets under construction is categorized as a Level III fair value measurement. The total remaining estimated recoverable amount and salvage values for Sundance Unit 5 repowering project was $33 million. Discounting did not have a material impact on these asset impairments. The asset retirement and project suspension decisions were based on the Company's assessment of future market conditions, the age and condition of in-service units, as well as TransAlta's strategic focus toward renewable energy solutions.

During 2021, with the expected closure of the Highvale mine at the end of 2021, it was determined that the estimated salvage value of the Highvale mine exceeded its economic benefit to the Alberta Merchant CGU. The asset was removed from the Alberta Merchant CGU for impairment purposes and was assessed for impairment as an individual asset, which resulted in the recognized impairment charge of $195 million in the Energy Transition segment, with the asset being written down to salvage value.

Corporate

Energy Transfer Canada, formerly SemCAMS Midstream ULC, purported to terminate the agreements related to the development and construction of the Kaybob Cogeneration Project. As a result, during the first quarter of 2021, the Company recorded impairment charges of $27 million in the Corporate segment as this facility was not yet operational. The recoverable amount was based on estimated fair value less costs of disposal of reselling the equipment purchased to date. During the fourth quarter of 2022, the dispute was settled. The Company reversed $2 million of the impairment loss previously recognized.

8. Net Other Operating (Income) Loss

Net other operating (income) loss includes the following:

Year ended Dec. 31	2023	2022	2021
Alberta Off-Coal Agreement	**(40)**	(40)	(40)
Liquidated damages recoverable	**(6)**	(12)	—
Insurance recoveries	**(1)**	(7)	—
Supplier, other contract settlements and other	**—**	1	34
Onerous contract provisions	**—**	—	14
Net other operating (income) loss	**(47)**	(58)	8

Alberta Off-Coal Agreement ("OCA")

The Company receives payments from the Government of Alberta for the cessation of coal-fired emissions on or before Dec. 31, 2030. Under the terms of the agreement, the Company receives annual cash payments on or before July 31 of approximately $40 million ($37 million, net of the non-controlling interest related to Sheerness), which commenced Jan. 1, 2017, and will terminate at the end of 2030. The Company recognizes the off-coal payments evenly throughout the year. Receipt of the payments is subject to certain terms and conditions. The OCA's main condition is the cessation of all coal-fired emissions on or before Dec. 31, 2030, which has been achieved effective Dec. 31, 2021. The affected plants are not, however, precluded from generating electricity at any time by any method, other than generation resulting in coal-fired emissions after Dec. 31, 2030.

Liquidated Damages Recoverable

During 2023, the Company recognized $3 million of recoverable liquidated damages related to requirements to be met by the contractor on turbine availability at the Windrise wind facility (2022 - $12 million) and $3 million for availability guarantees at other facilities (2022 - nil).

Insurance Recoveries

During 2023, the Company received insurance proceeds of $1 million related to the replacement costs for the single tower failure at the Kent Hills wind facilities (2022 - $7 million).

Supplier, Other Contract Settlements and Other

During 2021, $34 million was expensed related to decisions to suspend the Sundance Unit 5 repowering project and to retire Keephills Unit 1, including a deferred asset of $10 million (US$8 million) for which the Company is unlikely to incur sufficient capital or operating expenditures to utilize the remaining credit.

Onerous Contract Provisions

During 2021, an onerous contract provision for future royalty payments of $14 million was recognized with the shutdown of the Highvale mine.

9. Investments

The change in investments is as follows:

	EMG	Skookumchuck	Tent Mountain	EIP	Ekona	Total
Classification	Equity-accounted	Equity-accounted	Equity-accounted	FVTPL	FVTOCI	
Balance, Dec. 31, 2021	12	93	—	—	—	105
Investment	—	—	—	10	2	12
Equity income (loss)	(1)	10	—	—	—	9
Distributions received	—	(5)	—	—	—	(5)
Changes in foreign exchange rates	1	7	—	1	—	9
Net change in fair value recognized in OCI	—	—	—	—	(1)	(1)
Balance, Dec. 31, 2022	12	105	—	11	1	129
Investment	**—**	**—**	**10**	**4**	**—**	**14**
Equity income (loss)	**(4)**	**8**	**—**	**—**	**—**	**4**
Distributions received	**—**	**(6)**	**—**	**—**	**—**	**(6)**
Changes in foreign exchange rates	**—**	**(3)**	**—**	**—**	**—**	**(3)**
Balance, Dec. 31, 2023	**8**	**104**	**10**	**15**	**1**	**138**

Equity-accounted Investments

The Company's investments in joint ventures and associates that are accounted for using the equity method consist of its investments in Skookumchuck, EMG and Tent Mountain Renewable Energy Complex ("Tent Mountain").

EMG International, LLC ("EMG")

TransAlta holds a 30 per cent interest in EMG, a wastewater treatment processing company. Earnings are derived from the design and construction of wastewater treatment facilities. During 2022, the contingent purchase price consideration of US$3.5 million was paid, which was calculated based on actual earnings metrics achieved in 2021 and did not differ from the estimated amount included in the initial purchase price.

Skookumchuck Wind Project

TransAlta holds a 49 per cent membership interest in SP Skookumchuck Investment, LLC. Skookumchuck is a 136.8 MW wind project located in Lewis and Thurston counties near Centralia in Washington state. The project has a 20-year PPA with Puget Sound Energy.

Tent Mountain Pumped Hydro Development Project

On April 24, 2023, the Company acquired a 50 per cent interest in Tent Mountain, an early-stage 320 MW pumped hydro energy storage development project, located in southwest Alberta, from Evolve Power Ltd. ("Evolve"), formerly known as Montem Resources Limited. The acquisition included land rights, fixed assets and intellectual property associated with the pumped hydro development project. The Company paid Evolve approximately $8 million on closing and made additional investments of $2 million during the balance of 2023. Additional contingent payments of up to $17 million may become payable to Evolve based on the achievement of specific development and commercial milestones. The Company and Evolve jointly control Tent Mountain, with the result that the Company accounts for its interest in the joint venture as an investment using the equity method.

Summarized financial information on the results of operations relating to the Company's pro-rata interests in Skookumchuck, EMG and Tent Mountain, is as follows:

Year ended Dec. 31	2023	2022	2021
Results of operations			
Revenues and other operating income	**22**	24	19
Expenses	**(18)**	(15)	(10)
Proportionate share of net earnings	**4**	9	9

Other Investments

Energy Impact Partners

On May 6, 2022, the Company entered into a commitment to invest US$25 million over the next four years in Energy Impact Partners ("EIP") Deep Decarbonization Frontier Fund 1 (the "Frontier Fund"). The investment in the Frontier Fund provides the Company with a portfolio approach to investing in emerging technologies and the opportunity to identify, pilot, commercialize and bring to market emerging technologies that will facilitate the transition to net-zero emissions. The investment is accounted for at FVTPL.

Ekona Power Inc.

On Feb. 1, 2022, the Company made an equity investment of $2 million in Ekona's Class B Preferred Shares. The investment will help support the commercialization of Ekona's novel methane pyrolysis technology platform, which is being developed to produce cleaner and lower-cost turquoise hydrogen. The Company has irrevocably elected to measure its investment in Ekona at FVTOCI.

10. Interest Expense

The components of interest expense are as follows:

	2023	2022	2021
Interest on debt	**203**	164	163
Interest on exchangeable debentures (Note 25)	**29**	29	29
Interest on exchangeable preferred shares (Note 25)	**28**	28	28
Capitalized interest (Note 18)	**(57)**	(16)	(14)
Interest on lease liabilities	**9**	7	7
Credit facility fees, bank charges and other interest	**21**	27	20
Tax shield on tax equity financing (Note 24)	**—**	(2)	(9)
Accretion of provisions (Note 23)	**48**	49	32
Interest expense	**281**	286	256

11. Income Taxes

Consolidated Statements of Earnings

I. Rate Reconciliation

Year ended Dec. 31	2023	2022	2021
Earnings (loss) before income taxes	**880**	353	(380)
Net earnings attributable to non-controlling interests not subject to tax	**(80)**	(94)	(33)
Adjusted earnings (loss) before income taxes	**800**	259	(413)
Statutory Canadian federal and provincial income tax rate (%)	**23.4%**	23.4%	23.6%
Expected income tax expense (recovery)	**187**	61	(98)
Increase (decrease) in income taxes resulting from:			
Differences in effective foreign tax rates	**9**	(1)	4
Non-deductible expense[(1)]	**58**	130	—
Taxable capital (gain) loss	**(2)**	18	—
Deferred income tax recovery related to temporary difference on investment in subsidiaries	**(3)**	(2)	—
Write-down (reversal of write-down) of unrecognized deferred income tax assets	**(178)**	(24)	134
Statutory and other rate differences	**1**	(3)	4
Adjustments in respect of deferred income tax of previous years	**1**	6	(4)
Other	**11**	7	5
Income tax expense	**84**	192	45
Effective tax rate (%)	**11%**	74%	(11%)

(1) This amount is related to current and prior period tax adjustments in the US to mitigate cash tax relating to the Base Erosion and Anti-Abuse Tax.

II. Components of Income Tax Expense

The components of income tax expense are as follows:

Year ended Dec. 31	2023	2022	2021
Current income tax expense	**50**	65	56
Deferred income tax expense (recovery) related to the origination and reversal of temporary differences	**215**	153	(145)
Deferred income tax recovery related to temporary difference on investment in subsidiaries	**(3)**	(2)	—
Write-down (reversal of write-down) of unrecognized deferred income tax assets(1)	**(178)**	(24)	134
Income tax expense	**84**	192	45
Current income tax expense	**50**	65	56
Deferred income tax expense (recovery)	**34**	127	(11)
Income tax expense	**84**	192	45

(1) During the year ended Dec. 31, 2023, the Company recognized deferred tax assets of $178 million (2022 - $24 million, 2021 - $134 million write-down). The deferred income tax assets mainly relate to the tax benefits associated with tax losses related to the Company's directly owned US operations and other deductible differences. The Company has not recognized an additional $157 million of deferred tax assets on the basis that it is not probable that sufficient future taxable income would be available to utilize these tax assets.

Consolidated Statements of Changes in Equity

The aggregate current and deferred income tax related to items charged or credited to equity are as follows:

Year ended Dec. 31	2023	2022	2021
Income tax expense (recovery) related to:			
Net impact related to cash flow hedges	**27**	(112)	(57)
Net impact related to hedges of foreign operations	**1**	(3)	—
Net impact related to net actuarial gains (losses)	**(1)**	12	11
Transaction costs for the acquisition of TransAlta Renewables	**(2)**	—	—
Income tax expense (recovery) reported in equity	**25**	(103)	(46)

Consolidated Statements of Financial Position

Significant components of the Company's deferred income tax assets (liabilities) are as follows:

As at Dec. 31	2023	2022
Non-capital losses[1]	**88**	244
Future decommissioning and restoration costs	**111**	119
Property, plant and equipment	**(605)**	(553)
Risk management assets and liabilities, net	**144**	193
Employee future benefits and compensation plans	**50**	48
Foreign exchange differences on US-denominated debt	**12**	13
Other taxable temporary differences	**(8)**	(5)
Net deferred income tax asset (liability), before write-down of deferred income tax assets	**(208)**	59
Unrecognized deferred income tax assets	**(157)**	(361)
Net deferred income tax liability, after write-down of deferred income tax assets	**(365)**	(302)

(1) Non-capital losses expire between 2033 and 2043. Net operating losses from US operations have no expiration.

The net deferred income tax liability is presented in the Consolidated Statements of Financial Position as follows:

As at Dec. 31	2023	2022
Deferred income tax assets[1]	**21**	50
Deferred income tax liabilities	**(386)**	(352)
Net deferred income tax liability	**(365)**	(302)

(1) The deferred income tax assets presented on the Consolidated Statements of Financial Position are recoverable based on estimated future earnings and tax planning strategies. The assumptions used in the estimate of future earnings are based on the Company's long-range forecasts.

Contingencies

As of Dec. 31, 2023, the Company had recognized a net liability of nil (2022 – nil) related to uncertain tax positions.

12. Non-Controlling Interests

The Company's subsidiaries and operations that have non-controlling interests are as follows:

Subsidiary / Operation	Non-controlling interest owner	Non-controlling interest as at Dec. 31, 2023	Non-controlling interest as at Dec. 31, 2022
TransAlta Cogeneration LP	Canadian Power Holdings Inc.	**49.99%**	49.99%
Kent Hills Wind LP	Natural Forces Technologies Inc.	**17%**	17%
TransAlta Renewables Inc.	Public shareholders	**nil(1)**	39.9%

(1) Non-controlling interest from Jan. 1, 2023 to Oct. 4, 2023 was 39.9%.

TransAlta Cogeneration, LP ("TA Cogen") operates a portfolio of cogeneration facilities in Canada and owns 50 per cent of a dual-fuel generating facility.

Kent Hills Wind LP owns and operates the 167 MW Kent Hills (1, 2 and 3) wind facilities located in New Brunswick. Kent Hills Wind LP is a subsidiary of TransAlta Renewables Inc. ("TransAlta Renewables").

TransAlta Renewables owns a portfolio of gas and renewable power generation facilities in Canada and owns economic interests in various other gas and renewable facilities of the Company. On Oct. 5, 2023, the Company acquired all of the outstanding common shares of TransAlta Renewables not already owned, directly or indirectly, by TransAlta and certain of its affiliates. TransAlta Renewables at Dec. 31, 2023, is a wholly owned subsidiary of the Company. Refer to Note 4 for more details.

Summarized financial information relating to subsidiaries with significant non-controlling interests is as follows:

TA Cogen

Year ended Dec. 31	2023	2022	2021
Revenues	**290**	347	265
Net earnings and total comprehensive income	**121**	143	103
Amounts attributable to the non-controlling interest:			
Net earnings	**80**	91	62
Total comprehensive income	**80**	91	62
Distributions paid to Canadian Power Holdings Inc.	**148**	87	56

As at Dec. 31	2023	2022
Current assets	**43**	127
Long-term assets	**193**	253
Current liabilities	**(41)**	(62)
Long-term liabilities	**(34)**	(27)
Total equity	**(161)**	(291)
Equity attributable to Canadian Power Holdings Inc.	**(79)**	(147)
Non-controlling interest share (per cent)	**49.99**	49.99

Kent Hills Wind LP

Prior to Oct 5, 2023, financial information related to the 17 per cent non-controlling interest in Kent Hills Wind LP was included in the financial information disclosed in TransAlta Renewables in this note.

Year ended Dec. 31	2023[(1)]
Revenues	**7**
Net earnings and total comprehensive income	**2**
Amounts attributable to the non-controlling interest:	
Net earnings and total comprehensive income	**—**

(1) This represents financial information from Oct. 5, 2023 to Dec. 31, 2023. The net earnings attributable to non-controlling interest in Kent Hills Wind LP prior to Oct. 5, 2023, is included in the disclosures for TransAlta Renewables.

As at Dec. 31	2023
Current assets	**35**
Long-term assets	**481**
Current liabilities	**(42)**
Long-term liabilities	**(188)**
Total equity	**(285)**
Equity attributable to non-controlling interests	**(48)**
Non-controlling interest share (per cent)	**17**

TransAlta Renewables

The financial information disclosed below includes the 17 per cent non-controlling interest in Kent Hills Wind LP until Oct. 5, 2023.

Year ended Dec. 31	2023[(1)]	2022	2021
Revenues	**303**	560	470
Net earnings	**56**	74	139
Total comprehensive income (loss)	**(7)**	(67)	66
Amounts attributable to the non-controlling interests:			
Net earnings	**21**	20	50
Total comprehensive income (loss)	**(4)**	(36)	21
Distributions paid to non-controlling interests	**75**	100	100

(1) Non-controlling interest share prior the close of the transaction on Oct. 5, 2023. This represents financial information from Jan. 1, 2023 to Oct. 4, 2023.

As at Dec. 31	2022
Current assets	240
Long-term assets	2,989
Current liabilities	(306)
Long-term liabilities	(1,118)
Total equity	(1,805)
Equity attributable to non-controlling interests	(732)
Non-controlling interests' share (per cent)	39.9

13. Trade and Other Receivables and Accounts Payable

As at Dec. 31	2023	2022
Trade accounts receivable	**600**	1,165
Collateral provided (Note 15)	**145**	304
Current portion of finance lease receivables (Note 17)	**19**	52
Loan receivable (Note 22)	**1**	4
Income taxes receivable	**42**	64
Trade and other receivables	**807**	1,589

As at Dec. 31	2023	2022
Accounts payable and accrued liabilities	**772**	1,069
Interest payable	**16**	17
Collateral held (Note 15)	**9**	260
Accounts payable and accrued liabilities	**797**	1,346

14. Financial Instruments

A. Financial Assets and Liabilities — Classification and Measurement

Financial assets and financial liabilities are measured on an ongoing basis at cost, fair value or amortized cost.

Carrying value as at Dec. 31, 2023	Derivatives used for hedging	Derivatives held for trading (FVTPL)	Amortized cost	Other financial assets (FVTPL)	Other financial assets (FVOCI)	Total
Financial assets						
Cash and cash equivalents[1]	—	—	348	—	—	348
Restricted cash	—	—	69	—	—	69
Trade and other receivables	—	—	807	—	—	807
Long-term portion of finance lease receivables	—	—	171	—	—	171
Long-term portion of loan receivable[2]	—	—	25	—	—	25
Other investments[3]	—	—	—	15	1	16
Risk management assets						
Current	—	151	—	—	—	151
Long-term	—	52	—	—	—	52
Financial liabilities						
Bank overdraft	—	—	3	—	—	3
Accounts payable and accrued liabilities	—	—	797	—	—	797
Dividends payable	—	—	49	—	—	49
Risk management liabilities						
Current	125	189	—	—	—	314
Long-term	80	194	—	—	—	274
Credit facilities, long-term debt and lease liabilities[4]	—	—	3,466	—	—	3,466
Exchangeable securities	—	—	744	—	—	744

(1) Includes cash equivalents of nil.

(2) Included in other assets. Refer to Note 22.

(3) Included in investments. Refer to Note 9.

(4) Includes current portion.

Carrying value as at Dec. 31, 2022	Derivatives used for hedging	Derivatives held for trading (FVTPL)	Amortized cost	Other financial assets (FVTPL)	Other financial assets (FVTOCI)	Total
Financial assets						
Cash and cash equivalents(1)	—	—	1,134	—	—	1,134
Restricted cash	—	—	70	—	—	70
Trade and other receivables	—	—	1,589	—	—	1,589
Long-term portion of finance lease receivables	—	—	129	—	—	129
Long-term portion of loan receivable(2)	—	—	33	—	—	33
Other investments(3)	—	—	—	11	1	12
Risk management assets						
Current	—	709	—	—	—	709
Long-term	—	161	—	—	—	161
Financial liabilities						
Bank overdraft	—	—	16	—	—	16
Accounts payable and accrued liabilities	—	—	1,346	—	—	1,346
Dividends payable	—	—	68	—	—	68
Risk management liabilities						
Current	271	858	—	—	—	1,129
Long-term	76	257	—	—	—	333
Credit facilities, long-term debt and lease liabilities(4)	—	—	3,653	—	—	3,653
Exchangeable securities	—	—	739	—	—	739

(1) Includes cash equivalents of nil.

(2) Included in other assets. Refer to Note 22.

(3) Included in investments. Refer to Note 9.

(4) Includes current portion.

B. Fair Value of Financial Instruments

The fair value of a financial instrument is the price that would be received when selling the asset or paid to transfer the associated liability in an orderly transaction between market participants at the measurement date. Fair values can be determined by observing quoted prices for the instrument in active markets to which the Company has access. In the absence of an active market, the Company determines fair values based on valuation models or by reference to other similar products in active markets.

Fair values determined using valuation models require the use of assumptions. In determining those assumptions, the Company looks primarily to external readily observable market inputs. However, if not available, the Company uses inputs that are not based on observable market data.

I. Level I, II and III Fair Value Measurements

The Level I, II and III classifications in the fair value hierarchy utilized by the Company are defined below. The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based on the lowest level input that is significant to the derivation of the fair value. The Level III classification is the lowest level classification in the fair value hierarchy.

a. Level I

Fair values are determined using inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Company has the ability to access at the measurement date. In determining Level I fair values, the Company uses quoted prices for identically traded commodities obtained from active exchanges such as the New York Mercantile Exchange.

b. Level II

Fair values are determined, directly or indirectly, using inputs that are observable for the asset or liability.

Fair values falling within the Level II category are determined through the use of quoted prices in active markets, which in some cases are adjusted for factors specific to the asset or liability, such as basis, credit valuation and location differentials.

The Company's commodity risk management Level II financial instruments include over-the-counter derivatives with values based on observable commodity futures curves and derivatives with inputs validated by broker quotes or other publicly available market data providers. Level II fair values are also determined using valuation techniques, such as option pricing models and interpolation formulas, where the inputs are readily observable.

In determining Level II fair values of other risk management assets and liabilities, the Company uses observable inputs other than unadjusted quoted prices that are observable for the asset or liability, such as interest rate yield curves and currency rates. For certain financial instruments where insufficient trading volume or lack of recent trades exists, the Company relies on similar interest or currency rate inputs and other third-party information such as credit spreads.

c. Level III

Fair values are determined using inputs for the assets or liabilities that are not readily observable.

The Company may enter into commodity transactions for which market-observable data is not available. In these cases, Level III fair values are determined using valuation techniques such as mark-to-forecast and mark-to-model. For mark-to-model valuations, derivative pricing models, regression-based models and scenario analysis simulation models may be employed. The model inputs may be based on historical data such as unit availability, transmission congestion, demand profiles for individual non-standard deals and structured products and/or volatility and correlations between products derived from historical price relationships. For assets and liabilities that are recognized at fair value on a recurring basis, the Company determines whether transfers have occurred between levels in the hierarchy by re-assessing categorization (based on the lowest level input that is significant to the fair value measurement as a whole) at the end of each reporting period.

The Company also has various commodity contracts with terms that extend beyond a liquid trading period. As forward market prices are not available for the full period of these contracts, the value of these contracts is derived by reference to a forecast that is based on a combination of external and internal fundamental modelling, including discounting. As a result, these contracts are classified in Level III.

II. Commodity Risk Management Assets and Liabilities

Commodity risk management assets and liabilities include risk management assets and liabilities that are used in the energy marketing and generation segments in relation to trading activities and certain contracting activities. To the extent applicable, changes in net risk management assets and liabilities for non-hedge positions are reflected within earnings of these businesses.

Commodity risk management assets and liabilities classified by fair value levels as at Dec. 31, 2023, are as follows: Level I – $13 million net liability (Dec. 31, 2022 – $23 million net asset), Level II – $244 million net liability (Dec. 31, 2022 – $173 million net asset) and Level III – $147 million net liability (Dec. 31, 2022 – $782 million net liability).

Significant changes in commodity net risk management assets (liabilities) during the year ended Dec. 31, 2023, are primarily attributable to contract settlements and volatility in market prices across multiple markets on both existing contracts and new contracts.

The following table summarizes the key factors impacting the fair value of the Level III commodity risk management assets and liabilities by classification during the years ended Dec. 31, 2023 and 2022, respectively:

	Year ended Dec. 31, 2023			Year ended Dec. 31, 2022		
	Hedge	Non-hedge	Total	Hedge	Non-hedge	Total
Opening balance	(347)	(435)	(782)	285	(126)	159
Changes attributable to:						
Market price changes on existing contracts	(123)	(6)	(129)	(611)	(298)	(909)
Market price changes on new contracts	—	18	18	—	(124)	(124)
Contracts settled	256	269	525	(38)	118	80
Change in foreign exchange rates	9	7	16	17	(5)	12
Transfers out of Level III[(1)]	205	—	205	—	—	—
Net risk management assets (liabilities) at end of year	—	(147)	(147)	(347)	(435)	(782)
Additional Level III information:						
Losses recognized in other comprehensive loss	(114)	—	(114)	(594)	—	(594)
Total gains (losses) included in earnings before income taxes	(256)	19	(237)	38	(427)	(389)
Unrealized gains (losses) included in earnings before income taxes relating to net assets (liabilities) held at year end	—	288	288	—	(309)	(309)

(1) The Company has a long-term fixed price power sale contract in the US for delivery of power. The fair value of this instrument was transferred out of Level III to Level II as at Dec. 31, 2023 as the forward price curve is now based on observable market prices for the remaining duration of the contract.

The Company has a Commodity Exposure Management Policy that governs both the commodity transactions undertaken in its proprietary trading business and those undertaken to manage commodity price exposures in its generation business. This Policy defines and specifies the controls and management responsibilities associated with commodity trading activities, as well as the nature and frequency of required reporting of such activities.

The Company's risk management department determines methodologies and procedures regarding commodity risk management Level III fair value measurements. Level III fair values are primarily calculated within the Company's energy trading risk management processes. These calculations are based on underlying contractual data as well as observable and non-observable inputs. Development of non-observable inputs requires the use of judgment. To ensure reasonability, the Level III fair value measurements are reviewed and validated by the risk management and finance departments. Review occurs formally on a quarterly basis or more frequently if daily review and monitoring procedures identify unexpected changes to fair value or changes to key parameters.

As at Dec. 31, 2023, the total Level III risk management asset balance was $56 million (Dec. 31, 2022 – $31 million) and Level III risk management liability balance was $203 million (Dec. 31, 2022 – $813 million). The net risk management liabilities decreased mainly due to market price changes and settled contracts. The information on risk management contracts or groups of risk management contracts that are included in Level III measurements and the related unobservable inputs and sensitivities are outlined in the following table. These include the effects on fair value of discounting, liquidity and credit value adjustments; however, the potential offsetting effects of Level II positions are not considered. Sensitivity ranges for the base fair values are determined using reasonably possible alternative assumptions for the key unobservable inputs, which may include forward commodity prices, volatility in commodity prices and correlations, delivery volumes, escalation rates and cost of supply.

As at		Dec. 31, 2023		
Description	**Valuation technique**	**Unobservable input**	**Reasonably possible change**	**Sensitivity**[1]
Coal transportation – US	Numerical derivative valuation	Volatility	80% to 120%	+6
		Rail rate escalation	zero to 10%	-4
Full requirements – Eastern US	Scenario analysis	Volume	96% to 104%	+3
		Cost of supply	Decrease of $2.30 per MWh or increase of $2.40 per MWh	-3
Long-term wind energy sale – Eastern US	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease or increase of US$6	+24
		Illiquid future REC prices (per unit)	Price decrease of US$12 or increase of US$8	
		Wind discounts	0% decrease or 9% increase	-28
Long-term wind energy sale – Canada	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of C$81 or increase of C$5	+65
		Wind discounts	16% decrease or 5% increase	-23
Long-term wind energy sale - Central US	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$1 or increase of US$2	+81
		Wind discounts	5% decrease or 2% increase	-36

(1) Sensitivity represents the total increase or decrease in recognized fair value that could arise from the use of the reasonably possible changes of all unobservable inputs.

As at		Dec. 31, 2022		
Description	**Valuation technique**	**Unobservable input**	**Reasonably possible change**	**Sensitivity[(1)]**
Coal transportation – US	Numerical derivative valuation	Illiquid future power prices (per MWh)	Price decrease of US$5 or increase of US$55	+14
		Volatility	80% to 120%	
		Rail rate escalation	zero to 10%	-13
Full requirements - Eastern US	Scenario analysis	Volume	96% to 104%	+3
		Cost of supply	Decrease of US$0.50 per MWh or increase of US$3.30 per MWh	-21
Long-term wind energy sale – Eastern US	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease or increase of US$6	+22
		Illiquid future REC prices (per unit)	Price decrease or increase of US$2	
		Wind discounts	0% decrease or 5% increase	-18
Long-term wind energy sale – Canada	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of C$85 or increase of C$5	+47
		Wind discounts	28% decrease or 5% increase	-25
Long-term wind energy sale – Central US	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease or increase of US$2	+74
		Wind discounts	2% decrease or 5% increase	-28
Long-term power sale – US	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$5 or increase of US$55	+15 -163

(1) Sensitivity represents the total increase or decrease in recognized fair value that would arise from the use of the reasonably possible changes of all unobservable inputs.

a. Coal Transportation – US

The Company has a coal rail transport agreement that includes an upside sharing mechanism until Dec. 31, 2025. Option pricing techniques have been utilized to value the obligation associated with this component of the agreement.

The key unobservable inputs used in the valuation include option volatility and rail rate escalation. Option volatility and rail rate escalation ranges have been determined based on historical data and professional judgment.

In the first three quarters of 2023, non-liquid power prices were also used as a key unobservable input. At Dec. 31, 2023, the relevant forward power prices were observable in the market.

b. Full Requirements – Eastern US

The Company has a portfolio of full requirement service contracts, whereby the Company agrees to supply specific utility customer needs for a range of products that may include electrical energy, capacity, transmission, ancillary services, renewable energy credits ("RECs") and independent system operator costs.

The key unobservable inputs used in the portfolio valuation include delivered volume and supply cost. Hourly shaping of consumption will result in a realized cost that may be at a premium (or discount) relative to the average settled price.

c. Long-Term Wind Energy Sale – Eastern US

The Company is party to a long-term contract for differences ("CFD") for the offtake of 100 per cent of the generation from its 90 MW Big Level wind facility. The CFD, together with the sale of electricity generated into the PJM Interconnection at the prevailing real-time energy market price, achieve the fixed contract price per MWh on proxy generation. Under the CFD, if the market price is lower than the fixed contract price the customer pays the Company the difference and if the market price is higher than the fixed contract price the Company refunds the difference to the customer. The customer is also entitled to the physical delivery of environmental attributes. The contract matures in December 2034. The contract is accounted for as a derivative. Changes in fair value are presented in revenue.

The key unobservable inputs used in the valuation of the contract are expected proxy generation volumes and non-liquid forward prices for power, RECs and wind discounts.

d. Long-Term Wind Energy Sale – Canada

The Company is party to two Virtual Power Purchase Agreements ("VPPAs") for the offtake of 100 per cent of the generation from its 130 MW Garden Plain wind facility. The VPPAs, together with the sale of electricity generated into the Alberta power market at the pool price, achieve the fixed contract prices per MWh. Under the VPPAs, if the pool price is lower than the fixed contract price the customer pays the Company the difference and if the pool price is higher than the fixed contract price the Company refunds the difference to the customer. The customers are also entitled to the physical delivery of environmental attributes. Both VPPAs commenced on commercial operation of the facility which was achieved in August 2023, and extend for a weighted average of approximately 17 years.

The energy components of these contracts are accounted for as derivatives. Changes in fair value are presented in revenue.

The key unobservable inputs used in the valuations of the contracts are the non-liquid forward prices for power and monthly wind discounts.

e. Long-Term Wind Energy Sale – Central US

The Company is party to two long-term VPPAs for the offtake of 100 per cent of the generation from its 300 MW White Rock East and White Rock West wind power projects. The VPPAs, together with the sale of electricity generated into the US Southwest Power Pool ("SPP") market at the relevant price nodes, achieve the fixed contract prices per MWh. Under the VPPAs, if the SPP pricing is lower than the fixed contract price the customers pay the Company the difference, and if the SPP pricing is higher than the fixed contract price, the Company refunds the difference to the customers. The customer is also entitled to the physical delivery of environmental attributes. During the fourth quarter of 2023, the Company and the customer for the White Rock wind projects amended the associated VPPAs. The VPPAs commence on commercial operation of the facilities.

The Company is also party to a VPPA for the offtake of 100 per cent of the generation from its 200 MW Horizon Hill wind power project. The VPPA, together with the sale of electricity generated into the SPP market at the relevant price node, achieve the fixed contract price per MWh. Under the VPPA, if the SPP pricing is lower than the fixed contract price the customer pays the Company the difference and if the SPP pricing is higher than the fixed contract price the Company refunds the difference to the customer. The customer remains entitled to the physical delivery of environmental attributes. During the second quarter of 2023, the Company and the customer for the Horizon Hill wind project amended the associated VPPA. The VPPA commences on commercial operation of the facility. Commissioning of the Horizon Hill wind project is expected during the first quarter of 2024.

The energy components of these contracts are accounted for as derivatives. Changes in fair value are presented in revenue. The amendments to the Horizon Hill and White Rock VPPAs did not change the nature of the contracts and the energy components continue to be accounted for as derivatives.

The key unobservable inputs used in the valuation of the contracts are the non-liquid forward prices for power and wind discounts.

f. Long-Term Power Sale – US

The Company has a long-term fixed price power sale contract in the US for delivery of power at the following capacity levels: 380 MW through Dec. 31, 2024, and 300 MW through Dec. 31, 2025. The contract is designated as an all-in-one cash flow hedge.

At Dec. 31, 2023, the contract was transferred to Level II as all significant inputs were observable. In the first three quarters of 2023, the term of the transaction extended beyond where the relevant forward power prices were observable in the market.

III. Other Risk Management Assets and Liabilities

Other risk management assets and liabilities primarily include risk management assets and liabilities that are used in managing exposures on non-energy marketing transactions such as interest rates, the net investment in foreign operations and other foreign currency risks. Hedge accounting is not always applied.

Other risk management assets and liabilities with a total net asset fair value of $19 million as at Dec. 31, 2023 (Dec. 31, 2022 – $6 million net liability) are classified as Level II fair value measurements. The changes in other net risk management assets and liabilities during the year ended Dec. 31, 2023, are attributable to favourable market price changes on existing contracts, favourable foreign exchange rates on new contracts entered into during 2023, and contracts settled during 2023.

IV. Other Financial Assets and Liabilities

The fair value of financial assets and liabilities measured at other than fair value is as follows:

	Fair value(1)				Total carrying value(1)
	Level I	Level II	Level III	Total	
Exchangeable securities — Dec. 31, 2023	**—**	**718**	**—**	**718**	**744**
Long-term debt — Dec. 31, 2023	**—**	**3,104**	**—**	**3,104**	**3,323**
Loan receivable — Dec. 31, 2023	**—**	**26**	**—**	**26**	**26**
Exchangeable securities — Dec. 31, 2022	—	685	—	685	739
Long-term debt — Dec. 31, 2022	—	3,200	—	3,200	3,518
Loan receivable — Dec. 31, 2022	—	37	—	37	37

(1) Includes current portion.

The fair values of the Company's debentures, senior notes and exchangeable securities are determined using prices observed in secondary markets. Non-recourse and other long-term debt fair values are determined by calculating an implied price based on a current assessment of the yield to maturity.

The carrying amount of other short-term financial assets and liabilities (cash and cash equivalents, restricted cash, trade accounts receivable, collateral provided, bank overdraft, accounts payable and accrued liabilities, collateral held and dividends payable) approximates fair value due to the liquid nature of the asset or liability. The fair values of the finance lease receivables approximate the carrying amounts as the amounts receivable represent cash flows from repayments of principal and interest.

C. Inception Gains and Losses

The majority of derivatives traded by the Company are based on adjusted quoted prices on an active exchange or extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using inputs that are not readily observable. Refer to section B of this Note 14 above for fair value Level III valuation techniques used. In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the "transaction price") and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net earnings (loss) only if the fair value of the instrument is evidenced by a quoted market price in an active market, observable current market transactions that are substantially the same, or a valuation technique that uses observable market inputs. Where these criteria are not met, the difference is deferred on the Consolidated Statements of Financial Position in risk management assets or liabilities and is recognized in net earnings (loss) over the term of the related contract. The difference between the transaction price and the fair value determined using a valuation model, yet to be recognized in net earnings (loss) and a reconciliation of changes is as follows:

As at Dec. 31	2023	2022	2021
Unamortized net loss at beginning of year	**(213)**	(131)	(33)
New inception gains (losses)(1)	**47**	(37)	(79)
Change resulting from amended contract(2)	**190**	—	—
Change in foreign exchange rates	**6**	(10)	—
Amortization recorded in net earnings during the year	**(27)**	(35)	(19)
Unamortized net gain (loss) at end of year	**3**	(213)	(131)

(1) During 2023, the Company entered into long-term fixed price power sale contracts with certain of its US customers and as a result recognized day one inception gains that are based on the forward price curve at the inception of the contract. During 2022, the Company entered into a PPA for the Horizon Hill wind project (2021 – PPAs for the White Rock wind projects) that resulted in new inception losses due to the difference between the fixed PPA price and future estimated market prices. There are other key factors, such as project economics and incentives, that influence the long-term power price for renewable projects outside of the power price curve, which is not liquid for the majority of the duration of the PPA.

(2) During 2023, the Company entered into certain contract amendments related to the Horizon Hill and White Rock wind projects. These amendments were mainly specific to obtaining price increases over the contract term. Accordingly, certain inception loss calibration adjustments were recognized within the risk management liability.

15. Risk Management Activities

A. Risk Management Strategy

The Company is exposed to market risk from changes in commodity prices, foreign exchange rates, interest rates, credit risk and liquidity risk. These risks affect the Company's earnings and the value of associated financial instruments that the Company holds. In certain cases, the Company seeks to minimize the effects of these risks by using derivatives to hedge its risk exposures. The Company's risk management strategy, policies and controls are designed to ensure that the risks it assumes comply with the Company's internal objectives and its risk tolerance.

The Company has two primary streams of risk management activities: (i) financial exposure management; and (ii) commodity exposure management. Within these activities, risks identified for management include commodity risk, interest rate risk, liquidity risk, equity price risk and foreign currency risk.

The Company seeks to minimize the effects of commodity risk, interest rate risk and foreign currency risk by using derivative financial instruments to hedge risk exposures. Of these derivatives, the Company may apply hedge accounting to those hedging commodity price risk, interest rate risk and foreign currency risk.

The use of financial derivatives is governed by the Company's policies approved by the Board, which provide written principles on commodity risk, interest rate risk, liquidity risk, equity price risk and foreign currency risk, as well as the use of financial derivatives and non-derivative financial instruments.

Liquidity risk, credit risk and equity price risk are managed through means other than derivatives or hedge accounting.

The Company enters into various derivative transactions as well as other contracting activities that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting. As a result, the related assets and liabilities are classified as derivatives at fair value through profit and loss. The net realized and unrealized gains or losses from changes in the fair value of these derivatives are reported in net earnings in the period the change occurs.

The Company designates certain derivatives as hedging instruments to hedge commodity price risk, foreign currency exchange risk in cash flow hedges and hedges of net investments in foreign operations. Hedges of foreign exchange risk on firm commitments are accounted for as cash flow hedges.

At the inception of the hedge relationship, the Company documents the relationship between the hedging instrument and the hedged item, along with its risk management objectives and its strategy for undertaking various hedge transactions. At the inception of the hedge and on an ongoing basis, the Company also documents whether the hedging instrument is effective in offsetting changes in fair values or cash flows of the hedged item attributable to the hedged risk, which is when the hedging relationships meet all of the following hedge effectiveness requirements:

- There is an economic relationship between the hedged item and the hedging instrument;
- The effect of credit risk does not dominate the value changes that result from that economic relationship; and
- The hedge ratio of the hedging relationship is the same as that resulting from the quantity of the hedged item that the Company actually hedges and the quantity of the hedging instrument that the entity actually uses to hedge that quantity of hedged item.

If a hedging relationship ceases to meet the hedge effectiveness requirement relating to the hedge ratio, but the risk management objective for that designated hedging relationship remains the same, the Company adjusts the hedge ratio of the hedging relationship so that it continues to meet the qualifying criteria.

B. Net Risk Management Assets and Liabilities

Aggregate net risk management assets (liabilities) are as follows:

As at Dec. 31, 2023

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	**(125)**	**(53)**	**(178)**
Long-term	**(80)**	**(146)**	**(226)**
Net commodity risk management liabilities	**(205)**	**(199)**	**(404)**
Other			
Current	**—**	**15**	**15**
Long-term	**—**	**4**	**4**
Net other risk management assets	**—**	**19**	**19**
Total net risk management liabilities	**(205)**	**(180)**	**(385)**

As at Dec. 31, 2022

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	(271)	(143)	(414)
Long-term	(76)	(96)	(172)
Net commodity risk management liabilities	(347)	(239)	(586)
Other			
Current	—	(6)	(6)
Long-term	—	—	—
Net other risk management liabilities	—	(6)	(6)
Total net risk management liabilities	(347)	(245)	(592)

Netting Arrangements

Information about the Company's financial assets and liabilities that are subject to enforceable master netting arrangements or similar agreements is as follows:

As at Dec. 31, 2023	Gross amounts of recognized financial assets (liabilities)	Amounts set off	Net amounts included on the statement of financial position	Master netting arrangements[1]	Net amount
Current risk management assets	528	(355)	173	(7)	166
Long-term risk management assets	161	(91)	70	(2)	68
Current risk management liabilities	(504)	355	(149)	7	(142)
Long-term risk management liabilities	(145)	91	(54)	2	(52)
Trade and other receivables[2]	789	(646)	143	(11)	132
Accounts payable and accrued liabilities[2]	(760)	646	(114)	11	(103)

As at Dec. 31, 2022	Gross amounts of recognized financial assets (liabilities)	Amounts set off	Net amounts included on the statement of financial position	Master netting arrangements[1]	Net amount
Current risk management assets	1,602	(883)	719	(62)	657
Long-term risk management assets	204	(43)	161	(7)	154
Current risk management liabilities	(1,953)	883	(1,070)	62	(1,008)
Long-term risk management liabilities	(449)	43	(406)	7	(399)
Trade and other receivables[2]	1,330	(934)	396	(176)	220
Accounts payable and accrued liabilities[2]	(1,344)	934	(410)	176	(234)

(1) Amounts not set off in the Consolidated Statements of Financial Position.

(2) The trade and other receivables and accounts payable and accrued liabilities include amounts related to collateral provided and held. Refer to Note 15(F) below for further details.

C. Nature and Extent of Risks Arising from Financial Instruments

I. Market Risk

a. Commodity Price Risk Management

The Company has exposure to movements in certain commodity prices in both its electricity generation and proprietary trading businesses, including the market price of electricity and fuels used to produce electricity. Most of the Company's electricity generation and related fuel supply contracts are considered to be contracts for delivery or receipt of a non-financial item in accordance with the Company's expected own use requirements and are not considered to be financial instruments. As such, the discussion related to commodity price risk is limited to the Company's proprietary trading business, the VPPAs and other long-term contracts that are derivatives and commodity derivatives used in hedging relationships associated with the Company's electricity generating activities.

To mitigate the risk of adverse commodity price changes, the Company uses three tools:

- A framework of risk controls;
- A predefined hedging plan, including fixed price financial power swaps and long-term physical power sale contracts to hedge commodity price for electricity generation; and
- A committee dedicated to overseeing the risk and compliance program in trading and ensuring the existence of appropriate controls, processes, systems and procedures to monitor adherence to the program.

The Company has executed commodity price hedges for its Centralia thermal facility, including a long-term physical power sale contract, and may, at times, execute hedges for its electricity price exposure in Alberta using fixed price financial swaps or other similar instruments. Both hedging strategies fall under the Company's risk management strategy used to hedge commodity price risk.

Market risk exposures are measured using Value at Risk ("VaR") supplemented by sensitivity analysis. There has been no change to the Company's exposure to market risks or the manner in which these risks are managed or measured. Position sizes and trade strategies were adjusted to remain within the Company's risk framework.

i. Commodity Price Risk Management – Proprietary Trading

The Company's Energy Marketing segment conducts proprietary trading activities and uses a variety of instruments to manage risk, earn trading revenue and gain market information.

In compliance with the Commodity Exposure Management Policy, proprietary trading activities are subject to limits and controls, including VaR limits. The Board approves the limit for total VaR from proprietary trading activities. VaR is the most commonly used metric employed to track and manage the market risk associated with trading positions.

A VaR measure gives, for a specific confidence level, an estimated maximum pre-tax loss that could be incurred over a specified period of time. VaR is used to determine the potential change in value of the Company's proprietary trading portfolio, over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations. VaR is estimated using the historical variance/covariance approach. VaR is a measure that has certain inherent limitations. The use of historical information in the estimate assumes that price movements in the past will be indicative of future market risk. As such, it may only be meaningful under normal market conditions. Extreme market events are not addressed by this risk measure. In addition, the use of a three-day measurement period implies that positions can be unwound or hedged within three days, although this may not be possible if the market becomes illiquid.

Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. VaR at Dec. 31, 2023, associated with the Company's proprietary trading activities was $4 million (2022 – $4 million, 2021 - $2 million).

ii. Commodity Price Risk – Generation

The generation segments utilize various commodity contracts to manage the commodity price risk associated with electricity generation, fuel purchases, emissions and byproducts, as considered appropriate. A Commodity Exposure Management Policy is prepared and approved annually, which outlines the intended hedging strategies associated with the Company's generation assets and related commodity price risks. Controls also include restrictions on authorized instruments, management reviews on individual portfolios and approval of asset transactions that could add potential volatility to the Company's reported net earnings.

VaR at Dec. 31, 2023, associated with the Company's commodity derivative instruments used in generation hedging activities was $23 million (2022 – $97 million, 2021 – $33 million). For positions and economic hedges that do not meet hedge accounting requirements or for short-term optimization transactions such as buybacks entered into to offset existing hedge positions, these transactions are marked to the market value with changes in market prices associated with these transactions affecting net earnings in the period in which the price change occurs. VaR at Dec. 31, 2023, associated with these transactions was $16 million (2022 – $45 million, 2021 – $34 million). For the market risk related to long-term power sale and long-term wind energy sales contracts, refer to the Level III measurements table and the related unobservable inputs and sensitivities in Note 14(B)(II).

iii. Commodity Price Risk Management – Hedges

At Dec. 31, 2023, the Company had no outstanding commodity derivative instruments designated as hedging instruments, except for the long-term power sale - US contract. For further details on this contract, refer to Note 14(B)(II)(i).

iv. Commodity Price Risk Management – Non-Hedges

The Company's outstanding commodity derivative instruments not designated as hedging instruments are as follows:

As at Dec. 31	2023		2022	
Type (thousands)	Notional amount sold	Notional amount purchased	Notional amount sold	Notional amount purchased
Electricity (MWh)	54,043	12,628	55,821	13,934
Natural gas (GJ)	50,949	209,348	23,464	162,384
Transmission (MWh)	—	856	—	1,643
Emissions (MWh)	212	804	274	2,297
Emissions (tonnes)	4,450	5,125	300	300
Coal (tonnes)	—	5,172	—	7,746

b. Interest Rate Risk Management

Changes in interest rates can impact the Company's borrowing costs and cost of capital. Changes in the cost of capital could affect the feasibility of new growth initiatives. Interest rate risk also arises as the fair value of future cash flows from a financial instrument fluctuates because of changes in market interest rates.

The Company's syndicated credit facility, Term Facility ("Term Facility") and the Poplar Creek non-recourse bond are the only debt instruments subject to floating interest rates, which represent 14 per cent of the Company's total long-term debt as at Dec. 31, 2023 (2022 – 15 per cent). Interest rate risk is managed with the use of derivatives.

Interbank Offered Rate reform could impact interest rate risk with respect to the Company's credit facilities and the Poplar Creek non-recourse bond held by a TransAlta subsidiary. The term and credit facilities with $400 million outstanding (2022 – $433 million) reference the Canadian Dollar Offered Rate ("CDOR") for Canadian-dollar drawings, but include appropriate fallback language to replace this benchmark rate in the event of a benchmark transition. The Poplar Creek non-recourse bond with a face value as at Dec. 31, 2023 of $86 million (2022 – $95 million) pays interest based upon the three-month CDOR. Cessation of the three-month CDOR is anticipated to occur mid-2024.

c. Currency Rate Risk

The Company has exposure to various currencies, such as the US dollar and the Australian dollar, as a result of investments and operations in foreign jurisdictions, the net earnings from those operations and the acquisition of equipment and services from foreign suppliers.

The Company may enter into the following hedging strategies to mitigate currency rate risk, including:

- Foreign exchange forward contracts to mitigate adverse changes in foreign exchange rates on project-related expenditures and distributions received in foreign currencies;
- Foreign exchange forward contracts and cross-currency swaps to manage foreign exchange exposure on foreign-denominated debt not designated as a net investment hedge; and
- Designating foreign currency debt as a hedge of the net investment in foreign operations to mitigate the risk due to fluctuating exchange rates related to certain foreign subsidiaries.

The Company's target is to hedge a minimum of 60 per cent of our forecasted foreign operating cash flows over a four-year period. The US exposure will be managed with a combination of interest expense on our US-denominated debt and forward foreign exchange contracts and the Australian exposure will be managed with a combination of interest expense on our Australian-dollar denominated debt and forward foreign exchange contracts.

i. Net Investment Hedges

When designating foreign currency debt as a hedge of the Company's net investment in foreign subsidiaries, the Company has determined that the hedge is effective if the foreign currency of the net investment is the same as the currency of the hedge and therefore an economic relationship is present.

The Company's hedges of its net investment in foreign operations were comprised of US-dollar-denominated long-term debt with a face value of US$370 million (2022 – US$370 million).

ii. Non-Hedges

The Company also uses foreign currency contracts to manage its expected foreign operating cash flows and foreign exchange forward contracts to manage foreign exchange exposure on foreign-denominated debt not designated as a net investment hedge. Hedge accounting is not applied to these foreign currency contracts.

As at Dec. 31	2023				2022			
	Notional amount sold	**Notional amount purchased**	**Fair value asset (liability)**	**Maturity**	**Notional amount sold**	**Notional amount purchased**	**Fair value asset (liability)**	**Maturity**
Foreign exchange forward contracts – foreign-denominated receipts/expenditures								
	AUD125	**CAD113**	**(1)**	**2024-2027**	AUD183	CAD168	(1)	2023-2026
	USD828	**CAD1,113**	**19**	**2024-2027**	USD573	CAD761	(12)	2023-2025
	USD100	**AUD152**	**5**	**2024**	USD66	AUD102	4	2023
Foreign exchange forward contracts – foreign-denominated debt								
	CAD190	**USD140**	**(4)**	**2024**	CAD159	USD120	3	2023

iii. Impacts of Currency Rate Risk

The possible effect on net earnings and OCI, due to changes in foreign exchange rates associated with financial instruments denominated in currencies other than the Company's functional currency, is outlined below. The sensitivity analysis has been prepared using management's assessment that an average three cents (2022 – three cents, 2021 – three cents) increase or decrease in these currencies relative to the Canadian dollar is a reasonable potential change over the next quarter.

Year ended Dec. 31	2023		2022		2021	
Currency	Net earnings decrease[1]	OCI gain[1][2]	Net earnings increase (decrease)[1]	OCI gain[1][2]	Net earnings decrease[1]	OCI gain[1][2]
USD	**(11)**	**—**	(12)	—	(13)	1
AUD	**(3)**	**—**	(2)	—	1	—
Total	**(14)**	**—**	(14)	—	(12)	1

(1) These calculations assume an increase in the value of these currencies relative to the Canadian dollar. A decrease would have the opposite effect.

(2) The foreign exchange impact related to financial instruments designated as hedging instruments in net investment hedges has been excluded.

II. Credit Risk

Credit risk is the risk that customers or counterparties will cause a financial loss for the Company by failing to discharge their obligations and the risk to the Company associated with changes in creditworthiness of entities with which commercial exposures exist. The Company actively manages its exposure to credit risk by assessing the ability of counterparties to fulfil their obligations under the related contracts prior to entering into such contracts. The Company makes detailed assessments of the credit quality of all counterparties and, where appropriate, obtains corporate guarantees, cash collateral, third-party credit insurance and/or letters of credit to support the ultimate collection of these receivables. For commodity trading and origination, the Company sets strict credit limits for each counterparty and monitors exposures on a daily basis. TransAlta uses standard agreements that allow for the netting of exposures and often include margining provisions. If credit limits are exceeded, TransAlta will request collateral from the counterparty or halt trading activities with the counterparty.

The Company uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for customers and counterparties. The following table outlines the Company's maximum exposure to credit risk without taking into account collateral held, including the distribution of credit ratings, as at Dec. 31, 2023:

	Investment grade (per cent)	Non-investment grade (per cent)	Total (per cent)	Total amount
Trade and other receivables[1]	95	5	100	**807**
Long-term finance lease receivable	100	—	100	**171**
Risk management assets[1]	75	25	100	**203**
Loans receivable[2]	—	100	100	**26**
Total				**1,207**

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.

(2) Includes $26 million loans receivable included within other assets with counterparties that have no external credit rating.

An impairment analysis is performed at each reporting date using a provision matrix to measure expected credit losses. The provision rates are based on segment historical rates of default of trade receivables as well as incorporating forward-looking credit ratings and forecasted default rates. In addition to the calculation of expected credit losses, TransAlta monitors key forward-looking information as potential indicators that historical bad debt percentages, forward-looking S&P credit ratings and forecasted default rates would no longer be representative of future expected credit losses. The calculation reflects the probability-weighted outcome, the time value of money and reasonable and supportable information that is available at the reporting date about past events, current conditions and forecasts of future economic conditions. TransAlta evaluates the concentration of risk with respect to trade receivables as low, as its customers are located in several jurisdictions and industries.

The Company did not have material expected credit losses as at Dec. 31, 2023.

The Company's maximum exposure to credit risk at Dec. 31, 2023, without taking into account collateral held or right of set-off, is represented by the current carrying amounts of receivables and risk management assets as per the Consolidated Statements of Financial Position. Letters of credit and cash are the primary types of collateral held as security related to these amounts. The maximum credit exposure to any one customer for commodity trading operations and hedging, including the fair value of open trading, net of any collateral held, at Dec. 31, 2023, was $23 million (Dec. 31, 2022 – $64 million).

III. Liquidity Risk

Liquidity risk relates to the Company's ability to access capital to be used for capital projects, debt refinancing, proprietary trading activities, commodity hedging and general corporate purposes. As at Dec. 31, 2023, TransAlta maintains an investment grade rating from one credit rating agency and one notch below investment grade ratings from two credit rating agencies. Between 2024 and 2026, the Company has $400 million of debt maturing, and an additional $411 million of scheduled non-recourse debt principal payments.

Collateral is posted based on negotiated terms with counterparties, which can include the Company's senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Company's derivative instruments contain financial assurance provisions that require collateral to be posted only if a material adverse credit-related event occurs.

TransAlta manages liquidity risk by monitoring liquidity on trading positions; preparing and revising longer-term financing plans to reflect changes in business plans and the market availability of capital; reporting liquidity risk exposure for proprietary trading activities on a regular basis to the Risk Management Committee, senior management and the Audit, Finance and Risk Committee (on behalf of the Board); and maintaining sufficient undrawn committed credit lines to support potential liquidity requirements. The Company does not use derivatives or hedge accounting to manage liquidity risk. A maturity analysis of the Company's financial liabilities is as follows:

	2024	2025	2026	2027	2028	2029 and thereafter	Total
Bank overdraft	3	—	—	—	—	—	3
Accounts payable and accrued liabilities	797	—	—	—	—	—	797
Long-term debt(1)							
Credit facilities(1)	400	—	—	—	—	—	400
Debentures	—	—	—	—	—	251	251
Senior notes	—	—	—	—	—	924	924
Non-recourse – Hydro	—	—	—	—	—	39	39
Non-recourse – Wind & Solar	66	69	67	70	75	289	636
Non-recourse and other – Gas	46	58	61	65	66	707	1,003
Tax equity financing	14	15	15	18	21	27	110
Exchangeable securities(2)	—	—	—	—	—	750	750
Commodity risk management liabilities	169	123	15	12	12	73	404
Other risk management assets	(16)	(3)	—	—	—	—	(19)
Lease liabilities(3)	4	4	4	4	4	123	143
Interest on long-term debt and lease liabilities(4)	186	167	158	151	143	711	1,516
Interest on exchangeable securities(2)(4)	53	53	53	53	53	13	278
Dividends payable	49	—	—	—	—	—	49
Total	**1,771**	**486**	**373**	**373**	**374**	**3,907**	**7,284**

(1) Excludes impact of hedge accounting and derivatives.

(2) Cash payment could occur after Dec. 31, 2028 if exchangeable securities are not exchanged by Brookfield Renewable Partners or its affiliates (collectively "Brookfield"). At Brookfield's option, the exchangeable securities can be exchanged, at the earliest, on Jan. 1, 2025 (Note 25).

(3) Lease liabilities exclude a lease incentive of $12 million expected to be received in 2024, which is recognized in trade and other receivables.

(4) Not recognized as a financial liability on the Consolidated Statements of Financial Position.

IV. Equity Price Risk

Total Return Swaps

The Company has certain compensation, deferred and restricted share unit programs, the values of which depend on the common share price of the Company. The Company has fixed a portion of the settlement cost of these programs by entering into a total return swap for which hedge accounting has not been applied. The total return swap is cash settled every quarter based upon the difference between the fixed price and the market price of the Company's common shares at the end of each quarter.

D. Hedging Instruments – Uncertainty of Future Cash Flows

The following table outlines the terms and conditions of derivative hedging instruments and how they affect the amount, timing and uncertainty of future cash flows:

	Maturity					
	2024	2025	2026	2027	2028	2029
Cash flow hedges						
Commodity derivative instruments						
Electricity						
Notional amount (thousands of MWh)	3,338	2,628	—	—	—	—
Average price ($ per MWh)	78.18	80.13	—	—	—	—

E. Effects of Hedge Accounting on the Financial Position and Performance

I. Effect of Hedges

The impact of the hedging instruments on the statement of financial position is as follows:

As at Dec. 31, 2023	Notional amount	Carrying amount	Line item in the statement of financial position	Change in fair value used for measuring ineffectiveness
Commodity price risk				
Cash flow hedges				
Physical power sales[(1)]	5,966	(205)	Risk management liabilities	(114)
Foreign currency risk				
Net investment hedges				
Foreign-denominated debt	USD370	CAD489	Credit facilities, long-term debt and lease liabilities	—

(1) In thousands of MWh.

As at Dec. 31, 2022	Notional amount	Carrying amount	Line item in the statement of financial position	Change in fair value used for measuring ineffectiveness
Commodity price risk				
Cash flow hedges				
Physical power sales[1]	9,295	(347)	Risk management liabilities	(594)
Foreign currency risk				
Net investment hedges				
Foreign-denominated debt	USD370	CAD502	Credit facilities, long-term debt and lease liabilities	—

(1) In thousands of MWh.

The impact of the hedged items on the statement of financial position is as follows:

	2023		2022	
As at Dec. 31	Change in fair value used for measuring ineffectiveness	Cash flow hedge reserve[1]	Change in fair value used for measuring ineffectiveness	Cash flow hedge reserve[1]
Commodity price risk				
Cash flow hedges				
Power forecast sales – Centralia	**(114)**	**(129)**	(594)	(279)
	Change in fair value used for measuring ineffectiveness	Foreign currency translation reserve[1]	Change in fair value used for measuring ineffectiveness	Foreign currency translation reserve[1]
Foreign currency risk				
Net investment hedges				
Net investment in foreign subsidiaries	**—**	**(36)**	—	(39)

(1) Net of tax. Included in AOCI.

The hedging gain or loss recognized in OCI before tax is equal to the change in fair value used for measuring effectiveness for the net investment hedge. There is no ineffectiveness recognized in profit or loss.

The impact of designated cash flow hedges on OCI and net earnings is:

Year ended Dec. 31, 2023					
	Effective portion			Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain recognized in OCI	Location of gain reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
Commodity contracts	51	Revenue	83	Revenue	—
Forward starting interest rate swaps	—	Interest expense	(8)	Interest expense	—
OCI impact	**51**	**OCI impact**	**75**	**Net earnings impact**	—

Over the next 12 months, the Company estimates that approximately $89 million of after-tax losses will be reclassified from AOCI to net earnings. These estimates assume constant natural gas and power prices, interest rates and exchange rates over time; however, the actual amounts that will be reclassified may vary based on changes in these factors.

Year ended Dec. 31, 2022

	Effective portion		Ineffective portion		
Derivatives in cash flow hedging relationships	**Pre-tax gain (loss) recognized in OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss reclassified from OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss recognized in earnings**
Commodity contracts	(747)	Revenue	124	Revenue	—
Forward starting interest rate swaps	53	Interest expense	2	Interest expense	—
OCI impact	(694)	OCI impact	126	Net earnings impact	—

Year ended Dec. 31, 2021

	Effective portion		Ineffective portion		
Derivatives in cash flow hedging relationships	**Pre-tax gain (loss) recognized in OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss reclassified from OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss recognized in earnings**
Commodity contracts	(268)	Revenue	(13)	Revenue	—
Foreign exchange forwards on project hedges	—	Property, plant and equipment	1	Foreign exchange (gain) loss	—
Forward starting interest rate swaps	13	Interest expense	4	Interest expense	—
OCI impact	(255)	OCI impact	(8)	Net earnings impact	—

II. Effect of Non-Hedges

For the year ended Dec. 31, 2023, the Company recognized a net unrealized loss of $44 million (2022 – loss of $384 million, 2021 – gain of $97 million) related to commodity derivatives.

For the year ended Dec. 31, 2023, a gain of $11 million (2022 – gain of $20 million, 2021 – gain of $6 million) related to foreign exchange and other derivatives was recognized, which consists of net unrealized gains of $27 million (2022 – loss of $11 million, 2021 – gain of $4 million) and net realized losses of $16 million (2022 – gains of $31 million, 2021 – gains of $2 million), respectively.

F. Collateral

I. Financial Assets Provided as Collateral

At Dec. 31, 2023, the Company provided $145 million (Dec. 31, 2022 – $304 million) in cash and cash equivalents as collateral to regulated clearing agents as security for commodity trading activities. These funds are held in segregated accounts by the clearing agents. Collateral provided is included within trade and other receivables in the Consolidated Statements of Financial Position. At Dec. 31, 2023, the Company provided $19 million (Dec. 31, 2022 - $6 million) in surety bonds as security for commodity trading activities.

II. Financial Assets Held as Collateral

At Dec. 31, 2023, the Company held $9 million (Dec. 31, 2022 – $260 million) in cash collateral associated with counterparty obligations. Under the terms of the contracts, the Company may be obligated to pay interest on the outstanding balances and to return the principal when the counterparties have met their contractual obligations or when the amount of the obligation declines as a result of changes in market value. Interest payable to the counterparties on the collateral received is calculated in accordance with each contract. Collateral held is related to physical and financial derivative transactions in a net asset position and is included in accounts payable and accrued liabilities in the Consolidated Statements of Financial Position.

III. Contingent Features in Derivative Instruments

Collateral is posted in the normal course of business based on the Company's senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Company's derivative instruments contain financial assurance provisions that require collateral to be posted only if a material adverse credit-related event occurs.

At Dec. 31, 2023, the Company had posted collateral of $392 million (Dec. 31, 2022 – $820 million) in the form of letters of credit on physical and financial derivative transactions in a net liability position. Certain derivative agreements contain credit-risk-contingent features, which if triggered could result in the Company having to post an additional $154 million (Dec. 31, 2022 – $594 million) of collateral to its counterparties.

16. Inventory

The components of inventory are as follows:

As at Dec. 31	2023	2022
Parts, materials and supplies	**72**	83
Coal	**38**	43
Emission credits	**45**	27
Natural gas	**2**	4
Total	**157**	157

No inventory was pledged as security for liabilities.

As at Dec. 31, 2023, the Company holds 962,548 emission credits in inventory that were purchased externally with a recorded book value of $45 million (Dec. 31, 2022 – 963,068 emission credits with a recorded book value of $27 million). The Company also has 3,121,837 (Dec. 31, 2022 – 3,619,450) of internally generated eligible emission credits from the Company's Wind and Solar and Hydro segments which have no recorded book value. This includes the eligible emission performance credits earned by the Alberta Hydro facilities formerly under dispute that has now been resolved. Refer to Note 36 for details.

Emission credits can be sold externally or can be used to offset future emission obligations from our gas facilities located in Alberta, where the compliance price of carbon is expected to increase, resulting in a reduced cash cost for carbon compliance in the year of settlement.

In June 2023, the Company settled the 2022 carbon compliance obligation in cash. The compliance price of carbon for the 2022 obligation settled was $50 per tonne. It increased to $65 per tonne in 2023.

During 2022, the Company utilized 1,169,333 emission credits with a carrying value of $35 million to settle the 2021 carbon compliance obligation of $47 million. The difference of $12 million was recognized as a reduction in the Company's carbon compliance costs in 2022.

17. Finance Lease Receivables

Amounts receivable under the Company's finance leases include the Northern Goldfields solar facilities (2023), the Poplar Creek cogeneration facility (2023 and 2022) and the Southern Cross Energy facilities (2022), and are as follows:

	2023		2022	
As at Dec. 31	Minimum lease receipts	Present value of minimum lease receipts	Minimum lease receipts	Present value of minimum lease receipts
Within one year	**28**	**28**	62	55
Second to fifth years inclusive	**112**	**98**	81	75
More than five years	**117**	**64**	60	51
	257	**190**	203	181
Less: unearned finance lease income	**67**	**—**	22	—
Total finance lease receivables	**190**	**190**	181	181

	2023	2022
Included in the Consolidated Statements of Financial Position as:		
Current portion of finance lease receivables (Note 13)	**19**	52
Long-term portion of finance lease receivables	**171**	129
Total finance lease receivables	**190**	181

On Nov. 22, 2023, the Northern Goldfields solar facilities achieved commercial operation. As a result, the Company derecognized assets under construction and recognized a finance lease receivable of $61 million.

18. Property, Plant and Equipment

A reconciliation of the changes in the carrying amount of PP&E is as follows:

	Assets under construction	Land	Hydro	Wind and Solar	Gas generation	Energy Transition	Capital spares and other[1]	Total
Cost								
As at Dec. 31, 2021	184	96	867	3,276	4,087	4,513	366	13,389
Additions[2]	891	—	—	—	—	—	6	897
Additions from development projects	17	—	—	—	—	—	12	29
Disposals	—	(3)	—	—	(1)	(216)	—	(220)
Impairment (charges) reversals (Note 7)	2	—	(21)	(43)	—	—	—	(62)
Changes to decommissioning and restoration costs (Note 23)	—	—	(15)	(59)	(12)	10	2	(74)
Retirement of assets	—	—	(9)	(9)	(12)	(7)	(2)	(39)
Change in foreign exchange rates	13	—	—	45	(4)	97	2	153
Transfers of assets[3]	(144)	—	18	23	472	(423)	(7)	(61)
As at Dec. 31, 2022	963	93	840	3,233	4,530	3,974	379	14,012
Additions[2]	**869**	—	—	—	—	—	**6**	**875**
Disposals	—	**(3)**	—	—	—	**(30)**	—	**(33)**
Impairment reversals (Note 7)	—	—	**10**	**4**	—	—	—	**14**
Changes to decommissioning and restoration costs (Note 23)	—	—	**3**	**14**	**(22)**	**3**	**(1)**	**(3)**
Retirement of assets	**—**	**—**	**(7)**	**(18)**	**(124)**	**(7)**	**(108)**	**(264)**
Change in foreign exchange rates	**(26)**	**—**	**—**	**(18)**	**(7)**	**(42)**	**(1)**	**(94)**
Transfers of assets[3]	**(572)**	**—**	**38**	**439**	**50**	**16**	**31**	**2**
Transfers to finance lease receivable (Note 17)	**—**	**—**	**—**	**(61)**	**(4)**	**—**	**—**	**(65)**
As at Dec. 31, 2023	**1,234**	**90**	**884**	**3,593**	**4,423**	**3,914**	**306**	**14,444**
Accumulated depreciation								
As at Dec. 31, 2021	—	—	468	1,093	2,178	4,150	180	8,069
Depreciation	—	—	21	130	308	63	16	538
Retirement of assets	—	—	(8)	(6)	(10)	(7)	(2)	(33)
Disposals	—	—	—	—	(1)	(211)	—	(212)
Change in foreign exchange rates	—	—	—	11	2	89	—	102
Transfers of assets[3]	—	—	(3)	—	335	(340)	—	(8)
As at Dec. 31, 2022	—	—	478	1,228	2,812	3,744	194	8,456
Depreciation	**—**	**—**	**25**	**129**	**342**	**73**	**16**	**585**
Retirement of assets	**—**	**—**	**(4)**	**(15)**	**(101)**	**(7)**	**(108)**	**(235)**
Disposals	**—**	**—**	**—**	**—**	**—**	**(30)**	**—**	**(30)**
Change in foreign exchange rates	**—**	**—**	**—**	**(5)**	**(3)**	**(39)**	**—**	**(47)**
Transfers in (out) of PP&E[3]	**—**	**—**	**—**	**—**	**(1)**	**2**	**—**	**1**
As at Dec. 31, 2023	**—**	**—**	**499**	**1,337**	**3,049**	**3,743**	**102**	**8,730**
Carrying amount								
As at Dec. 31, 2021	184	96	399	2,183	1,909	363	186	5,320
As at Dec. 31, 2022	963	93	362	2,005	1,718	230	185	5,556
As at Dec. 31, 2023	**1,234**	**90**	**385**	**2,256**	**1,374**	**171**	**204**	**5,714**

(1) Includes major spare parts and standby equipment available, but not in service.

(2) In 2023, the Company capitalized $57 million (2022 – $16 million) of interest to PP&E in at a weighted average rate of 6.3 per cent (2022 – 6.0 per cent).

(3) Includes transfers of assets upon commissioning to assets in service and other movements.

Assets under Construction

During the year, the Company achieved commercial operations on the Garden Plain wind facility and the Northern Goldfields solar and battery storage facilities. Costs were transferred from assets under construction to the Wind and Solar segment. In addition, the Kent Hills Foundation Rehabilitation project was substantially completed and the costs were transferred to the Wind and Solar segment.

Change in Estimate - Useful Lives

During 2023, the Company adjusted the useful lives of certain assets in the Gas segment to reflect changes to the future operating expectations of the assets. This resulted in a decrease of $92 million in depreciation expense that was recognized in the Consolidated Statement of Earnings (Loss) in 2023.

During 2022, the Company adjusted the useful lives of certain assets included in the Gas segment to reflect changes to the future operating expectations of the assets. This resulted in an increase of $132 million in depreciation expense that was recognized in the Consolidated Statement of Earnings (Loss) in 2022.

19. Right-of-Use Assets

The Company leases various properties and types of equipment. Lease contracts are typically made for fixed periods. Leases are negotiated on an individual basis and contain a wide range of terms and conditions.

The lease agreements do not impose covenants, but leased assets may not be used as security for borrowing purposes.

A reconciliation of the changes in the carrying amount of the right-of-use assets is as follows:

	Land	Buildings	Vehicles	Equipment	Total
As at Dec. 31, 2021	68	20	1	6	95
Additions	36	—	1	3	40
Depreciation	(4)	(5)	—	(2)	(11)
Change in foreign exchange rates	2	—	—	—	2
As at Dec. 31, 2022	102	15	2	7	126
Additions	**2**	**2**	**1**	**—**	**5**
Depreciation	**(5)**	**(5)**	**—**	**(2)**	**(12)**
Change in foreign exchange rates	**(2)**	**—**	**—**	**—**	**(2)**
As at Dec. 31, 2023	**97**	**12**	**3**	**5**	**117**

For the year ended Dec. 31, 2023, TransAlta paid $19 million (2022 – $16 million) related to recognized lease liabilities, consisting of $10 million (2022 – $9 million) of principal repayments and $9 million (2022 – $7 million) of interest expense.

Short-term leases (term of less than 12 months) and leases with total lease payments below the Company's capitalization threshold (low value leases) do not require recognition as lease liabilities and right-of-use assets. For the year ended Dec. 31, 2023, the Company expensed $1 million (2022 – $2 million and 2021 – nil) related to short-term and low value leases.

Some of the Company's land leases that met the definition of a lease were not recognized as they require variable payments based on production or revenue.

Additionally, certain land leases require payments to be made on the basis of the greater of the minimum fixed payments and variable payments based on production or revenue. For these leases, lease liabilities have been recognized on the basis of the minimum fixed payments. For the year ended Dec. 31, 2023, the Company expensed $8 million (2022 – $8 million and 2021 – $6 million) in variable land lease payments for these leases.

20. Intangible Assets

A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Power sale contracts	Software and other	Intangibles under development	Coal rights	Total
Cost					
As at Dec. 31, 2021	269	422	4	132	827
Additions	—	—	31	—	31
Change in foreign exchange rates	3	3	1	—	7
Transfers	—	12	(9)	—	3
As at Dec. 31, 2022	272	437	27	132	868
Additions	—	—	**13**	—	**13**
Asset impairment charges	—	**(1)**	—	—	**(1)**
Change in foreign exchange rates	**(2)**	**(2)**	**(1)**	—	**(5)**
Transfers	—	**12**	**(12)**	—	—
As at Dec. 31, 2023	**270**	**446**	**27**	**132**	**875**
Accumulated amortization					
As at Dec. 31, 2021	140	299	—	132	571
Amortization	17	26	—	—	43
Change in foreign exchange rates	1	1	—	—	2
As at Dec. 31, 2022	158	326	—	132	616
Amortization	**17**	**21**	—	—	**38**
Change in foreign exchange rates	**(1)**	**(1)**	—	—	**(2)**
As at Dec. 31, 2023	**174**	**346**	—	**132**	**652**
Carrying amount					
As at Dec. 31, 2021	129	123	4	—	256
As at Dec. 31, 2022	114	111	27	—	252
As at Dec. 31, 2023	**96**	**100**	**27**	—	**223**

21. Goodwill

Goodwill acquired through business combinations has been allocated to groups of CGUs that are expected to benefit from the synergies of the acquisitions. Goodwill by segments is as follows:

As at Dec. 31	2023	2022
Hydro	**258**	258
Wind and Solar	**176**	176
Energy Marketing	**30**	30
Total goodwill	**464**	464

For the purposes of the 2023 goodwill impairment review, the Company determined the recoverable amounts of the Wind and Solar segment by calculating the fair value less costs of disposal using discounted cash flow projections. In 2023, the Company relied on the recoverable amounts determined in 2022 for the Hydro and Energy Marketing segments in performing the 2023 goodwill impairment review. The recoverable amounts are based on the Company's long-range forecasts for the periods extending to the last planned asset retirement in 2072. The resulting fair value measurements are categorized within Level III of the fair value hierarchy. No impairment of goodwill arose for any segment.

The key assumptions impacting the determination of fair value for the Hydro, Wind and Solar, and Energy Marketing segments are the following:

- Discount rates used ranged from 5.9 per cent to 8.2 per cent (2022 – 5.9 per cent to 8.2 per cent).
- Forecasts of electricity production for each facility are determined taking into consideration contracts for the sale of electricity, historical production, regional supply-demand balances and capital maintenance and expansion plans.
- Forecasts of sales prices for each facility are determined by taking into consideration contract prices for facilities subject to long- or short-term contracts, forward price curves for merchant plants and regional supply-demand balances. Where forward price curves are not available for the duration of the facility's useful life, prices are determined by extrapolation techniques using historical industry and company-specific data. Merchant electricity prices used in the Hydro and Wind and Solar models ranged between $20 to $238 per MWh during the forecast period (2022 – $28 to $233 per MWh).

22. Other Assets

The components of other assets are as follows:

As at Dec. 31	2023	2022
South Hedland prepaid transmission access and distribution costs	60	61
Long-term prepaids and other assets	41	40
Project development costs	35	10
Loans receivable	26	37
Transmission infrastructure	18	16
Total Other assets	180	164

Included in the Consolidated Statements of Financial Position as:		
Total current other assets (Note 13)	1	4
Total long-term other assets	179	160
Total Other assets	180	164

South Hedland prepaid transmission access and distribution costs are costs that are amortized on a straight-line basis over the South Hedland PPA contract life.

Long-term prepaids and other assets include the TransAlta Energy Transition Bill commitment and other contractually required prepayments and deposits. As part of the TransAlta Energy Transition Bill signed into law in the State of Washington and the subsequent Memorandum of Agreement ("MOA"), the Company committed to fund US$55 million in total over the remaining life of the Centralia coal plant to support economic and community development, promote energy efficiency and develop energy technologies related to the improvement of the environment. The MOA contains certain provisions for termination and in the event of termination and in certain circumstances, this funding or portion thereof would no longer be required. As of Dec. 31, 2023, the Company has fully funded the commitment.

Project development costs primarily include the pre-construction project costs for projects.

At Dec. 31, 2023, $25 million of the loans receivable (2022 – $37 million) is an unsecured loan related to an advancement by the Company's subsidiary, Kent Hills Wind LP, of the net financing proceeds of the Kent Hills Wind Bond ("KH Bonds"), to its 17 per cent partner. The loan bears interest at 4.55 per cent, with interest payable quarterly. No scheduled principal repayments are required until the maturity date of October 2027. However, repayments may be required for amounts associated with foundation replacement capital expenditures and for operating account funding, as outlined in the amendment made to the KH Bonds. During 2023, the Company received repayments of $12 million that were required as part of the waiver and amendment made to the KH Bonds (2022 - $18 million).

Transmission infrastructure was constructed by the Company and then transferred to a transmission provider upon completion. The balance relates to the Garden Plain and Windrise wind facilities and will be amortized to net earnings (loss) over the useful life of the facilities.

23. Decommissioning and Other Provisions

The change in decommissioning and other provision balances is as follows:

	Decommissioning and restoration	Other provisions	Total
Balance, Dec. 31, 2021	793	34	827
Liabilities incurred	1	23	24
Liabilities settled	(35)	(12)	(47)
Accretion	49	—	49
Disposals	(5)	—	(5)
Revisions in estimated cash flows	95	5	100
Revisions in discount rates	(225)	—	(225)
Reversals	—	(9)	(9)
Change in foreign exchange rates	15	—	15
Balance, Dec. 31, 2022	688	41	729
Liabilities incurred	**1**	**4**	**5**
Liabilities settled	**(37)**	**(13)**	**(50)**
Accretion (Note 10)	**47**	**1**	**48**
Revisions in estimated cash flows	**(89)**	**—**	**(89)**
Revisions in discount rates	**52**	**—**	**52**
Change in foreign exchange rates	**(6)**	**—**	**(6)**
Balance, Dec. 31, 2023	**656**	**33**	**689**

Included in the Consolidated Statements of Financial Position as:

As at	Dec. 31, 2023	Dec. 31, 2022
Current portion	**35**	70
Non-current portion	**654**	659
Total Decommissioning and other provisions	**689**	729

A. Decommissioning and Restoration

A provision has been recognized for all generating facilities and mines for which TransAlta is legally, or constructively, required to remove the facilities at the end of their useful lives and restore the sites to their original condition. TransAlta estimates that the undiscounted amount of cash flow required to settle these obligations is approximately $1.7 billion, which will be incurred between 2024 and 2072. The majority of the costs will be incurred between 2024 and 2050.

During 2023, the decommissioning and restoration provision decreased by $89 million due to revisions in estimated cash flows and timing of cash flows for certain Gas and Energy Transition assets. The timing of cash flows was adjusted to optimize and maximize efficiencies by staging required reclamation work. Operating assets included in PP&E decreased by $34 million and $55 million was recognized as an impairment reversal in net earnings related to retired assets.

During 2023, revisions in discount rates increased the decommissioning and restoration provision by $52 million due to a decrease in discount rates, largely driven by decreases in long-term market benchmark rates. On average, discount rates decreased compared to 2022, with rates ranging from 6.0 to 9.0 per cent as at Dec. 31, 2023. This has resulted in a corresponding increase in PP&E of $31 million on operating assets and the recognition of a $21 million impairment charge in net earnings related to retired assets.

During 2022, the Company accelerated the expected timing on decommissioning and restoration for certain facilities. This increased the decommissioning and restoration provision by $95 million, of which $46 million increased operating assets in PP&E and $49 million was recognized as an impairment charge in net earnings related to retired assets.

During 2022, the decommissioning and restoration provision decreased by $225 million due to a significant increase in discount rates, largely driven by increases in market benchmark rates. On average, discount rates increased with rates ranging from 7.0 to 9.7 per cent as at Dec. 31, 2022. This has resulted in a corresponding decrease in PP&E of $123 million on operating assets and the recognition of a $102 million impairment reversal in net earnings related to retired assets.

At Dec. 31, 2023, the Company has provided a surety bond in the amount of US$147 million (2022 – US$147 million) in support of future decommissioning obligations at the Centralia coal mine. At Dec. 31, 2023, the Company had provided a surety bond and letters of credit in the amount of $188 million (2022 – $187 million) in support of future decommissioning obligations at the Highvale mine.

B. Other Provisions

Other provisions include provisions arising from ongoing business activities, amounts related to commercial disputes between the Company and customers or suppliers and onerous contract provisions. Information about the expected timing of settlement and uncertainties that could impact the amount or timing of settlement has not been provided as this may impact the Company's ability to settle the provisions in the most favourable manner.

24. Credit Facilities, Long-Term Debt and Lease Liabilities

A. Amounts Outstanding

The amounts outstanding are as follows:

				2023			2022		
As at Dec. 31	Segment	Maturity	Currency	Carrying value	Face value	Interest[1]	Carrying value	Face value	Interest
Credit facilities									
Committed syndicated bank facility[2]	Corporate	2027	CAD	—	—	—	32	33	4.7%
Term Facility	Corporate	2024	CAD	397	400	7.4%	396	400	6.5%
Debentures									
7.3% Medium term notes	Corporate	2029	CAD	110	110	7.3%	110	110	7.3%
6.9% Medium term notes	Corporate	2030	CAD	141	141	6.9%	141	141	6.9%
Senior notes[3]									
7.8% Senior notes[4]	Corporate	2029	USD	520	528	7.8%	533	542	7.8%
6.5% Senior notes	Corporate	2040	USD	391	396	6.5%	401	407	6.5%
Non-recourse									
Melancthon Wolfe Wind LP bond	Wind & Solar	2028	CAD	168	169	3.8%	202	203	3.8%
New Richmond Wind LP bond	Wind & Solar	2032	CAD	103	104	4.0%	112	113	4.0%
Kent Hills Wind LP bond	Wind & Solar	2033	CAD	193	196	4.5%	206	209	4.5%
Windrise Wind LP bond	Wind & Solar	2041	CAD	164	167	3.4%	170	173	3.4%
Pingston bond	Hydro	2043	CAD	39	39	6.2%	45	45	3.0%
TAPC Holdings LP bond (Poplar Creek)	Gas	2030	CAD	85	86	9.4%	94	95	8.9%
TEC Hedland PTY Ltd bond[5]	Gas	2042	AUD	691	699	4.1%	711	720	4.1%
TransAlta OCP LP bond	Gas	2030	CAD	217	218	4.5%	241	242	4.5%
Tax equity financing									
Big Level & Antrim[6]	Wind & Solar	2029	USD	91	97	6.6%	102	108	6.6%
Lakeswind[7]	Wind & Solar	2029	USD	10	10	10.5%	15	15	10.5%
North Carolina Solar[8]	Wind & Solar	2028	USD	3	3	7.3%	6	6	7.3 %
Other[9]	Corporate		CAD	—	—	—	1	1	5.9%
Total long-term debt				3,323	3,363		3,518	3,563	
Lease liabilities[10]				143			135		
Total long-term debt and lease liabilities				3,466			3,653		
Less: current portion of long-term debt				(526)			(170)		
Less: current portion of lease liabilities				(6)			(8)		
Total current long-term debt and lease liabilities				(532)			(178)		
Total non-current credit facilities, long-term debt and lease liabilities				2,934			3,475		

(1) Interest rate reflects the stipulated rate or the average rate weighted by principal amounts outstanding and is before the effect of hedging.

(2) Composed of bankers' acceptances and other commercial borrowings under long-term committed credit facilities.

(3) US face value at Dec. 31, 2023 – US$700 million (2022 – US$700 million).

(4) The effective interest rate for the senior notes is 5.98 per cent after the effects of gains realized on settled interest rate hedging instruments.

(5) AU face value at Dec. 31, 2023 – AU$773 million (2022 – AU$786 million).

(6) US face value at Dec. 31, 2023 – US$73 million (2022 – US$79 million).

(7) US face value at Dec. 31, 2023 – US$8 million (2022 – US$11 million).

(8) US face value at Dec. 31, 2023 – US$2 million (2022 – US$5 million).

(9) Other debt consisted of an unsecured commercial loan obligation that matured and was repaid in 2023.

(10) At Dec. 31, 2023, lease liabilities exclude a lease incentive of $12 million expected to be received in 2024, which is recognized in trade and other receivables.

The Company's credit facilities are summarized in the table below:

As at Dec. 31, 2023		Utilized			
Credit Facilities	Facility size	Outstanding letters of credit[1]	Cash drawings	Available capacity	Maturity date
Committed					
TransAlta syndicated credit facility	1,950	417	—	1,533	Q2 2027
TransAlta bilateral credit facilities	240	178	—	62	Q2 2025
TransAlta Term Facility	400	—	400	—	Q3 2024
Total Committed	**2,590**	**595**	**400**	**1,595**	
Non-Committed					
TransAlta demand facilities	400	187	—	213	N/A
Total Non-Committed	**400**	**187**	**—**	**213**	

(1) TransAlta has obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties, including those related to potential environmental obligations, commodity risk management and hedging activities, pension plan obligations, construction projects and purchase obligations. Letters of credit drawn against the non-committed facilities reduce the available capacity under the committed syndicated credit facilities. At Dec. 31, 2023, TransAlta provided cash collateral of $145 million.

These facilities are the primary source of short-term liquidity after the cash flow generated from the Company's business.

The acquisition of TransAlta Renewables resulted in the TransAlta syndicated credit facility increasing by $700 million to approximately $2.0 billion, effectively consolidating the TransAlta Renewables syndicated credit facility into the TransAlta syndicated credit facility. Refer to Note 4 for more details.

The Company is in compliance with the terms of the credit facilities and all undrawn amounts are fully available. The $187 million letters of credit are issued from non-committed demand facilities; these obligations are backstopped and reduce the available capacity on the committed credit facilities. In addition to the $1.4 billion of committed capacity available under the credit facilities, the Company also had $345 million of available cash and cash equivalents, net of bank overdraft.

Senior Notes

On Nov. 15, 2022, the Company repaid the US$400 million 4.5 per cent unsecured senior notes on maturity in addition to related fees and expenses.

On Nov. 17, 2022, the Company issued US$400 million senior notes, which have a fixed coupon rate of 7.75 per cent per annum and mature on Nov. 15, 2029. Including the effects of settled interest rate swaps, the notes have an effective yield of approximately 5.982 per cent. The notes are unsecured and rank equally in right of payment with all of our existing and future senior indebtedness and senior in right of payment to all of our future subordinated indebtedness. The interest payments on the bonds are made semi-annually, on November 15 and May 15 with the first payment commencing May 15, 2023. TransAlta is required to allocate an amount equal to the net proceeds from this offering to finance or, refinance new and/or existing eligible green projects in accordance with its Green Bond Framework.

A total of US$370 million (2022 – US$370 million) of the senior notes have been designated as a hedge of the Company’s net investment in US operations.

Non-Recourse Debt

On May 8, 2023, the Pingston Power Inc. non-recourse bond matured with a total aggregate repayment of $46 million, consisting of accrued interest and principal.

On Sept. 14, 2023, the Company closed a non-recourse bond financing for approximately $39 million ("Pingston bond") as a replacement for the non-recourse bond that matured on May 8, 2023. The Pingston bond is secured by a first ranking charge over all the respective assets of the Company's subsidiaries that issued the bonds, amortizes and bears interest at a rate of 6.145 per cent per annum, payable semi-annually, and matures on May 8, 2043. The Pingston bond is subject to customary financing conditions and covenants that may restrict the Company's ability to access funds generated by the facility's operations.

Tax Equity

Tax equity financings are typically represented by the initial equity investments made by the project investors at each project (net of financing costs incurred), except for the Lakeswind and North Carolina Solar acquired tax equity financings, which were initially recognized at their fair values. Tax equity financing balances are reduced by the value of tax benefits (production tax credits, tax depreciation and investment tax credits) allocated to the investor and by cash distributions paid to the investor for their share of net earnings and cash flow generated at each project. Tax equity financing balances are increased by interest recognized at the implicit interest rate. The maturity dates of each financing are subject to change and are primarily dependent upon when the project investor achieves the agreed upon targeted rate of return. The Company anticipates the maturity dates of the tax equity financings will be: Big Level and Antrim in December 2029; Lakeswind in March 2029 and North Carolina Solar in December 2028.

Other

TransAlta's debt has terms and conditions, including financial covenants, that are considered normal and customary. As at Dec. 31, 2023, the Company was in compliance with all debt covenants.

B. Restrictions Related to Non-Recourse Debt and Other Debt

The Melancthon Wolfe Wind LP, Pingston Power Inc., TAPC Holdings LP, New Richmond Wind LP, Kent Hills Wind LP, TEC Hedland Pty Ltd and Windrise Wind LP non-recourse bonds and the TransAlta OCP LP bond, with a total carrying value of $1.7 billion as at Dec. 31, 2023 (2022 – $1.8 billion) are subject to customary financing conditions and covenants that may restrict the Company's ability to access funds generated by the facilities' operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the fourth quarter of 2023, with the exception of Kent Hills Wind LP and TAPC Holdings LP. Kent Hills Wind cannot make any distributions to its partners until the foundation work is completed. TAPC Holdings LP has been impacted by higher interest rates in 2023. The funds in these entities that have accumulated since the fourth quarter test will remain there until the next debt service coverage ratio can be calculated in the first quarter of 2024. At Dec. 31, 2023, $79 million (2022 – $50 million) of cash was subject to these financial restrictions.

At Dec. 31, 2023, $3 million (AU$3 million) of funds held by TEC Hedland Pty Ltd are not able to be accessed by other corporate entities as the funds must be solely used by the project entities for the purpose of paying major maintenance costs. Additionally, certain non-recourse bonds require that certain reserve accounts be established and funded through cash held on deposit and/or by providing letters of credit.

C. Security

Non-recourse debts totalling $1.4 billion as at Dec. 31, 2023 (2022 – $1.4 billion) are each secured by a first ranking charge over all of the respective assets of the Company's subsidiaries that issued the bonds, which include PP&E with total carrying amounts of $1.5 billion at Dec. 31, 2023 (2022 – $1.5 billion) and intangible assets with total carrying amounts of $61 million (2022 – $70 million). At Dec. 31, 2023, a non-recourse bond of approximately $85 million (2022 – $94 million) was secured by a first ranking charge over the equity interests of the issuer that issued the non-recourse bond.

The TransAlta OCP bonds have a carrying value of $217 million (2022 – $241 million) and are secured by the assets of TransAlta OCP, including the right to annual capital contributions and OCA payments from the Government of Alberta. Under the OCA, the Company receives annual cash payments on or before July 31 of approximately $40 million (approximately $37 million, net to the Company), commencing on Jan. 1, 2017 and terminating at the end of 2030.

D. Principal Repayments

	2024	2025	2026	2027	2028	2029 and thereafter	Total
Principal repayments[1]	526	142	143	153	162	2,237	**3,363**
Lease liabilities[2]	4	4	4	4	4	123	**143**

(1) Excludes impact of hedge accounting and derivatives.

(2) Lease liabilities exclude a lease incentive of $12 million, expected to be received in 2024, which is recognized in trade and other receivables.

E. Restricted Cash

As at Dec. 31, 2023, the Company had $17 million (2022 – $17 million) of restricted cash related to the TransAlta OCP bonds, which is required to be held in a debt service reserve account to fund scheduled future debt repayments. The Company also had $52 million (2022 – $53 million) of restricted cash related to the TEC Hedland Pty Ltd bond. These cash reserves are required to be held under commercial arrangements and for debt service, which may be replaced by letters of credit in the future.

F. Letters of Credit

Letters of credit issued by TransAlta are drawn on its $2.0 billion committed syndicated credit facility, its $240 million bilateral committed credit facilities and its $400 million uncommitted demand facilities. TransAlta has drawn $417 million on its committed syndicated credit facility, $178 million on its bilateral committed credit facilities and $187 million on its uncommitted demand facilities.

Letters of credit are issued to counterparties as required by various contractual arrangements with the Company and certain subsidiaries of the Company. If the Company or its subsidiary does not perform under such contracts, the counterparty may present its claim for payment to the financial institution through which the letter of credit was issued. All letters of credit expire within one year and are expected to be renewed, as needed, in the normal course of business. The total outstanding letters of credit as at Dec. 31, 2023, was $782 million (2022 – $1,175 million) with nil (2022 – nil) amounts exercised by third parties under these arrangements.

G. Currency Impacts

The weakening of the US dollar has decreased the US-denominated long-term debt balances, mainly the senior notes and tax equity financing, by $27 million as at Dec. 31, 2023 (2022 – increased $41 million due to the strengthening of the US dollar). Almost all of the US-denominated debt is hedged either through financial contracts or net investments in the US operations.

Additionally, the weakening of the Australian dollar has decreased the Australian-denominated non-recourse senior secured notes balance by approximately $9 million as at Dec. 31, 2023 (2022 – $9 million). As this debt is issued by an Australian subsidiary, the foreign currency translation impacts are recognized within other comprehensive income (loss).

25. Exchangeable Securities

On March 22, 2019, the Company entered into an Investment Agreement whereby Brookfield Renewable Partners or its affiliates (collectively "Brookfield") agreed to invest $750 million in TransAlta through the purchase of exchangeable securities, which are exchangeable into an equity ownership interest in TransAlta's Alberta Hydro Assets in the future at a value based on a multiple of the Alberta Hydro Assets' future-adjusted EBITDA ("Option to Exchange").

A. $750 Million Exchangeable Securities

	Dec. 31, 2023			Dec. 31, 2022		
As at	Carrying value	Face value	Interest	Carrying value	Face value	Interest
Exchangeable debentures – due May 1, 2039[1]	**344**	**350**	**7%**	339	350	7%
Exchangeable preferred shares[2]	**400**	**400**	**7%**	400	400	7%
Total exchangeable securities	**744**	**750**		739	750	

(1) Seven per cent unsecured subordinated debentures due May 1, 2039.

(2) Redeemable, retractable first preferred shares (Series I). Exchangeable preferred share dividends are reported as interest expense.

On Dec. 11, 2023, the Company declared a dividend of $7 million, in aggregate, for the Exchangeable Preferred Shares at the fixed rate of 1.764 per cent, per share, payable on Feb. 28, 2024. The Exchangeable Preferred Shares are considered debt for accounting purposes and, as such, dividends are reported as interest expense (Note 10).

B. Option to Exchange

As at	Dec. 31, 2023		Dec. 31, 2022	
Description	Base fair value	Sensitivity	Base fair value	Sensitivity
Option to exchange – embedded derivative	**—**	**+nil -25**	—	+nil -25

The Investment Agreement allows Brookfield the option to exchange all of the outstanding exchangeable securities after Dec. 31, 2024, into an equity ownership interest of up to a maximum 49 per cent in an entity that has been formed to hold TransAlta's Alberta Hydro Assets. The fair value of the option to exchange is considered a Level III fair value measurement as there is no available market-observable data. It is therefore valued using a mark-to-forecast model with inputs that are based on historical data and changes in underlying discount rates only when it represents a long-term change in the value of the option to exchange.

Sensitivity ranges for the base fair value are determined using reasonably possible alternative assumptions for key unobservable inputs, which is mainly the change in the implied discount rate of the future cash flow. The sensitivity analysis has been prepared using the Company's assessment that a change in the implied discount rate of the future cash flow of one per cent is a reasonably possible change.

The maximum equity interest Brookfield can own with respect to the Hydro Assets is 49 per cent. If Brookfield's ownership interest is less than 49 per cent at conversion, Brookfield has a one-time option payable in cash to increase its ownership to up to 49 per cent, exercisable up until Dec. 31, 2028, provided Brookfield holds at least 8.5 per cent of TransAlta's common shares. Under this top-up option, Brookfield will be able to acquire an additional 10 per cent interest in the entity holding the Hydro Assets, provided the 20-day volume-weighted average price ("VWAP") of TransAlta's common shares is not less than $14 per share prior to the exercise of the option and up to the full 49 per cent if the 20-day VWAP of TransAlta's common shares at that time is not less than $17 per share. To the extent the value of the investment would exceed a 49 per cent equity interest, Brookfield will be entitled to receive the balance of the redemption price in cash.

In connection with the Investment Agreement, Brookfield is entitled to nominate two directors for election to the Board.

26. Defined Benefit Obligation and Other Long-Term Liabilities

The components of defined benefit obligation and other long-term liabilities are as follows:

As at Dec. 31	2023	2022
Defined benefit obligation (Note 31)	**155**	150
Retail power contract liability	**83**	126
Other	**13**	18
Total	**251**	294

The liability for pension and post-employment benefits and associated costs included in compensation expenses are impacted by estimates related to changes in key actuarial assumptions, including discount rates. The defined benefit obligation has increased by $5 million to $155 million as at Dec. 31, 2023, from $150 million as at Dec. 31, 2022.

During 2023, the Company made a voluntary contribution of $4 million (US$3 million) to improve the funded status of the US Defined Benefit Pension Plan for the Centralia thermal facility.

During 2022, the Company made a voluntary contribution of $35 million to further improve the funded status of the Sunhills Mining Ltd. Pension Plan for the Highvale mine and to support the employees affected by the closure of the Highvale mine in 2021 and our transition off-coal to cleaner sources. The contribution reduces the amount of the Company's future funding obligations, including amounts secured by the letters of credit.

A one per cent increase in discount rates would result in a $40 million decrease in the defined benefit obligation. Refer to Note 31 for additional sensitivities impacting the defined benefit obligation.

On Dec. 1, 2022, the Company closed a purchase and sale agreement for customer retail contracts to deliver power and gas, along with power and gas financial swaps. The Company accounted for the purchase as an asset acquisition and allocated values to risk management assets of $139 million (Level II valuation) and retail power contract liabilities of $129 million within the Gas segment. The retail power contract liabilities acquired represent certain off-market retail power customer contracts for which fair value was determined as the present value of the amount by which contract terms deviated from the terms that a market participant could have achieved at the closing date. The retail contract liability is amortized to depreciation over the remaining term of the contracts based on volumes that will be delivered each month.

27. Common Shares

A. Issued and Outstanding

TransAlta is authorized to issue an unlimited number of voting common shares without nominal or par value.

	2023		2022	
As at Dec. 31	Common shares (millions)	Amount	Common shares (millions)	Amount
Issued and outstanding, beginning of period	**268.1**	**2,863**	271.0	2,901
Purchased and cancelled under the NCIB	**(7.5)**	**(80)**	(4.3)	(46)
Share-based payment plans	**0.8**	**6**	0.9	5
Stock options exercised	**0.7**	**5**	0.5	3
Issued for acquisition of TransAlta Renewables[1] (Note 4)	**46.5**	**510**	—	—
Issued and outstanding, end of year, prior to ASPP	**308.6**	**3,304**	268.1	2,863
Provision for repurchase of common shares under ASPP	**(1.7)**	**(19)**	—	—
Issued and outstanding, end of year	**306.9**	**3,285**	268.1	2,863

(1) Net of $4 million of transaction costs.

B. Normal Course Issuer Bid ("NCIB") Program

The effects of the Company's purchase and cancellation of common shares during the period are as follows:

For the year ended Dec. 31	2023	2022
Total shares purchased[1]	**7,537,500**	4,342,300
Average purchase price per share	**11.49**	12.48
Total cost (millions)	**87**	54
Book value of shares cancelled	**80**	46
Amount recorded in deficit	**(7)**	(8)

(1) At Dec. 31, 2023, includes 181,800 (2022 - 164,300) shares that were repurchased but were not cancelled due to timing differences between the transaction date and settlement date. As a result, $2 million (2022 - $2 million) was paid subsequent to the year end.

2023

On May 26, 2023, the Toronto Stock Exchange (“TSX”) accepted the notice filed by the Company to renew its normal course issuer bid for a portion of its common shares. Pursuant to the NCIB, TransAlta may repurchase up to a maximum of 14 million common shares, representing approximately 7.29 per cent of its public float of common shares as at May 17, 2023. Any common shares purchased under the NCIB are cancelled. The period during which TransAlta is authorized to make purchases under the NCIB commenced on May 31, 2023, and ends on May 30, 2024.

On Dec. 19, 2023, the Company entered into an Automatic Share Purchase Plan ("ASPP") which permits an independent broker to repurchase shares under the NCIB during the first quarter blackout period through to the end of the ASPP. The Company has recognized a provision of $19 million for the repurchase of common shares under the ASPP within accounts payables and accrued liabilities as at Dec. 31, 2023, as a estimate of the maximum number of shares that could be repurchased during the blackout period.

Shares purchased by the Company under the NCIB are recognized as a reduction to share capital equal to the average carrying value of the common shares. Any difference between the aggregate purchase price and the average carrying value of the common shares is recorded in deficit.

2022

On May 24, 2022, the TSX accepted the notice filed by the Company to renew its normal course issuer bid for a portion of its common shares. Pursuant to the NCIB, TransAlta may repurchase up to a maximum of 14 million common shares, representing approximately 7.16 per cent of its public float of common shares as at May 17, 2022.

C. Shareholder Rights Plan

The Company initially adopted the Shareholder Rights Plan in 1992, which was amended and restated on April 28, 2022. As required, the Shareholder Rights Plan must be put before the Company's shareholders every three years for approval. It was last approved on April 28, 2022, and will need to be approved at the annual meeting of shareholders in 2025. The primary objective of the Shareholder Rights Plan is to encourage a potential acquirer to meet certain minimum standards designed to promote the fair and equal treatment of all common shareholders. When an acquiring shareholder acquires 20 per cent or more of the Company's common shares, except in limited circumstances including by way of a "permitted bid" or a "competing permitted bid" (as defined in the Shareholder Rights Plan), the rights granted under the Shareholder Rights Plan become exercisable by all shareholders except those held by the acquiring shareholder. Each right will entitle a shareholder, other than the acquiring shareholder, to purchase additional common shares at a significant discount to market, thus exposing the person acquiring 20 per cent or more of the shares to substantial dilution of their holdings.

D. Earnings per Share

Year ended Dec. 31	2023	2022	2021
Net earnings (loss) attributable to common shareholders	**644**	4	(576)
Basic and diluted weighted average number of common shares outstanding (millions)	**276**	271	271
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**2.33**	0.01	(2.13)

E. Dividends

On Nov. 21, 2023, the Company declared a quarterly dividend of $0.06 per common share, payable on April 1, 2024.

There have been no transactions involving common shares between the reporting date and the date of completion of these Consolidated Financial Statements.

28. Preferred Shares

A. Issued and Outstanding

All preferred shares issued and outstanding are non-voting cumulative redeemable fixed or floating rate first preferred shares.

As at Dec. 31	2023		2022	
Series[(1)]	Number of shares (millions)	Amount	Number of shares (millions)	Amount
Series A	**9.6**	**235**	9.6	235
Series B	**2.4**	**58**	2.4	58
Series C	**10.0**	**243**	10.0	243
Series D	**1.0**	**26**	1.0	26
Series E	**9.0**	**219**	9.0	219
Series G	**6.6**	**161**	6.6	161
Issued and outstanding, end of period	**38.6**	**942**	38.6	942

(1) The Series I Preferred Shares are accounted for as long-term debt. Refer to Note 25.

I. Series C Cumulative Redeemable Rate Reset Preferred Shares Conversion

On June 30, 2022, the Company converted 1,044,299 of its 11.0 million Cumulative Redeemable Rate Reset First Preferred Shares, Series C ("Series C Shares"), on a one-for-one basis, into Cumulative Redeemable Floating Rate First Preferred Shares, Series D ("Series D Shares").

The Series C Shares pay fixed cumulative preferential cash dividends on a quarterly basis, for the five-year period from and including June 30, 2022, to but excluding June 30, 2027, if, as and when declared by the Board. The annual fixed dividend rate is 5.854 per cent, being equal to the five-year Government of Canada bond yield of 2.754 per cent determined as of May 31, 2022, plus 3.10 per cent, in accordance with the terms of the Series C Shares.

The Series D Shares pay quarterly floating rate cumulative preferential cash dividends for the five-year period from and including June 30, 2022, to but excluding June 30, 2027, if, as and when declared by the Board. The quarterly dividend rate for the Series D Shares is established each quarter, and is equal to the annual rate for the auction of 90-day Government of Canada Treasury Bills, plus 3.10 per cent, in accordance with the terms of the Series D Shares.

II. Series E Cumulative Fixed Redeemable Rate Reset Preferred Shares Conversion

On Sept. 21, 2022, the Company announced that, after taking into account all election notices received for the conversion of the Cumulative Redeemable Rate Reset Preferred Shares, Series E (the "Series E shares") into Cumulative Redeemable Floating Rate Preferred Shares Series F (the "Series F Shares"), there were 89,945 Series E Shares tendered for conversion, which was less than the one million shares required to give effect to conversions into Series F Shares. Therefore, none of the Series E Shares were converted into Series F Shares.

As a result, the Series E Shares will be entitled to receive quarterly fixed cumulative preferential cash dividends, if, as and when declared by the Board. The annual dividend rate for the Series E Shares for the five-year period from and including Sept. 30, 2022, to but excluding Sept. 30, 2027, will be 6.894 per cent, which is equal to the five-year Government of Canada bond yield of 3.244 per cent, determined as of Aug. 31, 2022, plus 3.65 per cent, in accordance with the terms of the Series E Shares.

Preferred Share Series Information

The holders are entitled to receive cumulative fixed quarterly cash dividends at specified rates, as approved by the Board. After an initial period of approximately five years from issuance and every five years thereafter ("Rate Reset Date"), the fixed rate resets to the sum of the then five-year Government of Canada bond yield (the fixed rate "Benchmark") plus a specified spread. Upon each Rate Reset Date, the shares are also:

- Redeemable at the option of the Company, in whole or in part, for $25.00 per share, plus all declared and unpaid dividends at the time of redemption.
- Convertible at the holder's option into a specified series of non-voting cumulative redeemable floating rate first preferred shares that pay cumulative floating rate quarterly cash dividends, as approved by the Board, based on the sum of the then Government of Canada 90-day Treasury Bill rate (the floating rate "Benchmark") plus a specified spread. The cumulative floating rate first preferred shares are also redeemable at the option of the Company and convertible back into each original cumulative fixed rate first preferred share series, at each subsequent Rate Reset Date, on the same terms as noted above.

Characteristics specific to each first preferred share series as at Dec. 31, 2023, are as follows:

Series(1)	Rate during term	Annual dividend rate per share ($)(2)	Next conversion date	Rate spread over benchmark (per cent)	Convertible to Series
A	Fixed	0.71924	March 31, 2026	2.03	B
B	Floating	1.718910	March 31, 2026	2.03	A
C	Fixed	1.46352	June 30, 2027	3.10	D
D	Floating	1.98695	June 30, 2027	3.10	C
E	Fixed	1.72352	Sept. 30, 2027	3.65	F
G	Fixed	1.24700	Sept. 30, 2024	3.80	H

(1) The Series I Preferred Shares are accounted for as long-term debt. Refer to Note 25.

(2) The annual dividend rate per share represents dividends declared in 2023.

B. Dividends

The following table summarizes the preferred share dividends declared in 2023 and 2022:

Series	Total dividends declared 2023(1)	2022(1)
A	**7**	7
B(2)	**4**	3
C	**15**	14
D(3)	**2**	1
E	**15**	13
G	**8**	8
Total for the year	**51**	46

(1) No dividends were declared in the first quarter of the year as the quarterly dividend related to the period covering the first quarter was declared in December of the prior year.

(2) Series B Preferred Shares pay quarterly dividends at a floating rate based on the 90-day Government of Canada Treasury Bill rate, plus 2.03 per cent.

(3) Series D Preferred Shares pay quarterly dividends at a floating rate based on the 90-day Government of Canada Treasury Bill rate, plus 3.10 per cent.

On Dec. 11, 2023, the Company declared a quarterly dividend of $0.17981 per share on the Series A preferred shares, $0.43958 per share on the Series B preferred shares, $0.36588 per share on the Series C preferred shares, $0.50609 per share on the Series D preferred shares, $0.43088 per share on the Series E preferred shares and $0.31175 per share on the Series G preferred shares, payable on March 31, 2024.

29. Accumulated Other Comprehensive Loss

The components of and changes in, accumulated other comprehensive loss are as follows:

	2023	2022
Currency translation adjustment		
Opening balance, Jan. 1	(39)	(35)
(Losses) gains on translating net assets of foreign operations, net of reclassifications to net earnings, net of tax	(6)	21
Gains (losses) on financial instruments designated as hedges of foreign operations, net of reclassifications to net earnings, net of tax(1)	9	(25)
Balance, Dec. 31	(36)	(39)
Cash flow hedges		
Opening balance, Jan. 1	(228)	228
Gains (losses) on derivatives designated as cash flow hedges, net of reclassifications to net earnings and to non-financial assets, net of tax(2)	99	(456)
Balance, Dec. 31	(129)	(228)
Employee future benefits		
Opening balance, Jan. 1	8	(29)
Net actuarial gains on defined benefit plans, net of tax(3)	(5)	37
Balance, Dec. 31	3	8
Other		
Opening balance, Jan. 1	37	(18)
Change in ownership of TransAlta Renewables	(64)	—
Intercompany and third-party investments at FVTOCI	25	55
Balance, Dec. 31	(2)	37
Accumulated other comprehensive loss	(164)	(222)

(1) Net of income tax expense of $1 million for the year ended Dec. 31, 2023 (Dec. 31, 2022 – $3 million recovery).

(2) Net of income tax expense of $27 million for the year ended Dec. 31, 2023 (Dec. 31, 2022 – $112 million recovery).

(3) Net of income tax recovery of $1 million for the year ended Dec. 31, 2023 (Dec. 31, 2022 – $12 million).

30. Share-Based Payment Plans

The Company has the following share-based payment plans:

A. Performance Share Unit ("PSU") and Restricted Share Unit ("RSU") Plan

Under the Share Unit Plan, grants of PSUs and RSUs may be made annually, but are measured and assessed over a three-year performance period. Grants are determined as a percentage of participants' base pay and are converted to PSUs or RSUs on the basis of the Company's common share price at the time of grant. Vesting of PSUs is subject to achievement over a three-year period of specific performance measures that are established at the time of each grant. RSUs are subject to a three-year cliff-vesting requirement. RSUs and PSUs track the Company's share price over the three-year period and accrue dividends as additional units at the same rate as dividends paid on the Company's common shares.

The pre-tax compensation expense related to PSUs and RSUs in 2023 was $21 million (2022 – $20 million, 2021 - $14 million), which is included in OM&A in the Consolidated Statements of Earnings (Loss).

B. Deferred Share Unit ("DSU") Plan

Under the Share Unit Plan, members of the Board and executives may, at their option, purchase DSUs using certain components of their fees or pay. A DSU is a notional share that has the same value as one common share of the Company and fluctuates based on the changes in the value of the Company's common shares in the marketplace. DSUs accrue dividends as additional DSUs at the same rate as dividends are paid on the Company's common shares. DSUs are redeemable in cash and may not be redeemed until the termination or retirement of the director or executive from the Company.

The Company accrues a liability and expense for the appreciation in the common share value in excess of the DSU's purchase price and for dividend equivalents earned.

The pre-tax compensation expense related to the DSUs was $1 million in 2023 (2022 - nil, 2021 – $3 million expense).

C. Stock Option Plan

In 2023, the Company granted executive officers of the Company a total of 0.4 million stock options with a weighted average exercise price of $12.02 that vest over a three-year period and expire seven years after issuance (2022 – 0.3 million stock options at $12.66; 2021 - 0.7 million stock options at $9.86). The expense recognized relating to these grants during 2023 was approximately $1 million (2022 – approximately $1 million, 2021 – approximately $2 million).

The total options outstanding and exercisable under the Stock Option Plan at Dec. 31, 2023, are outlined below:

	Options outstanding		
Range of exercise prices[1] ($ per share)	Number of options (millions)	Weighted average remaining contractual life (years)	Weighted average exercise price ($ per share)
5.00-12.00	**2.5**	**3.60**	**9.17**

(1) Options currently exercisable as at Dec. 31, 2023.

31. Employee Future Benefits

A. Description

The Company sponsors registered pension plans in Canada and the US covering substantially all employees of the Company in these countries and specific named employees working internationally. These plans have defined benefit and defined contribution options and in Canada there is an additional non-registered supplemental plan for eligible employees whose annual earnings exceed the Canadian income tax limit. Except for the Highvale pension plan acquired in 2013, the Canadian and US defined benefit pension plans are closed to new entrants. The US defined benefit pension plan was frozen effective Dec. 31, 2010, resulting in no future benefits being earned. The supplemental pension plan was closed as of Dec. 31, 2015, and a new defined contribution supplemental pension plan commenced for executive members effective Jan. 1, 2016. Current executives as of Dec. 31, 2015, were grandfathered into the old supplemental plan.

The latest actuarial valuation for accounting purposes of the US pension plan was at Jan. 1, 2022. The latest actuarial valuation for accounting purposes of the Highvale and Canadian pension plans was at Dec. 31, 2021. The measurement date used for all plans to determine the fair value of plan assets and the present value of the defined benefit obligation was Dec. 31, 2023.

Funding of the registered pension plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada, or more, depending on funding status and every year in the US. The supplemental pension plan is solely the obligation of the Company. The Company is not obligated to fund the supplemental plan but is obligated to pay benefits under the terms of the plan as they come due. The Company posted a letter of credit in March 2023 in the amount of $88 million, and provided $70 million in surety bonds, to secure the obligations under the supplemental plan and the Canadian defined benefit plan, respectively.

The Company provides other health and dental benefits to the age of 65 for both disabled members and retired members through its other post-employment benefits plans. The latest actuarial valuations for accounting purposes of the Canadian and US plans were as at Dec. 31, 2021 and Jan. 1, 2022, respectively. The measurement date used to determine the present value obligation for both plans was Dec. 31, 2023.

The Company provides several defined contribution plans, including an Australian superannuation plan and a US 401(k) savings plan, that provide for company contributions from five per cent to eleven per cent, depending on the plan. Optional employee contributions are allowed for all the defined contribution plans.

B. Costs Recognized

The costs recognized in net earnings during the year on the defined benefit, defined contribution and other post-employment benefits plans are as follows:

Year ended Dec. 31, 2023	Registered	Supplemental	Other	Total
Current service cost	**1**	**1**	**—**	**2**
Administration expenses	**1**	**—**	**—**	**1**
Interest cost on defined benefit obligation	**16**	**4**	**1**	**21**
Interest on plan assets	**(13)**	**(1)**	**—**	**(14)**
Defined benefit expense	**5**	**4**	**1**	**10**
Defined contribution expense	**11**	**—**	**—**	**11**
Net expense	**16**	**4**	**1**	**21**

Year ended Dec. 31, 2022	Registered	Supplemental	Other	Total
Current service cost	1	1	—	2
Administration expenses	1	—	—	1
Interest cost on defined benefit obligation	13	3	—	16
Interest on plan assets	(9)	—	—	(9)
Defined benefit expense	6	4	—	10
Defined contribution expense	11	—	—	11
Net expense	17	4	—	21

Year ended Dec. 31, 2021	Registered	Supplemental	Other	Total
Current service cost	3	2	1	6
Administration expenses	1	—	—	1
Interest cost on defined benefit obligation	12	2	—	14
Interest on plan assets	(8)	—	—	(8)
Curtailment and amendment gain	(7)	—	—	(7)
Defined benefit expense	1	4	1	6
Defined contribution expense	8	—	—	8
Net expense	9	4	1	14

C. Status of Plans

The status of the defined benefit pension and other post-employment benefit plans is as follows:

Year ended Dec. 31, 2023	**Registered**	**Supplemental**	**Other**	**Total**
Fair value of plan assets	**269**	**15**	**—**	**284**
Present value of defined benefit obligation	**(340)**	**(89)**	**(17)**	**(446)**
Funded status – plan deficit	**(71)**	**(74)**	**(17)**	**(162)**
Amount recognized in the Consolidated Financial Statements:				
Accrued current liabilities	**(1)**	**(5)**	**(1)**	**(7)**
Other long-term liabilities	**(70)**	**(69)**	**(16)**	**(155)**
Total amount recognized	**(71)**	**(74)**	**(17)**	**(162)**

Year ended Dec. 31, 2022	**Registered**	**Supplemental**	**Other**	**Total**
Fair value of plan assets	274	15	—	289
Present value of defined benefit obligation	(345)	(85)	(17)	(447)
Funded status – plan deficit	(71)	(70)	(17)	(158)
Amount recognized in the Consolidated Financial Statements:				
Accrued current liabilities	(1)	(6)	(1)	(8)
Other long-term liabilities	(70)	(64)	(16)	(150)
Total amount recognized	(71)	(70)	(17)	(158)

D. Plan Assets

The fair value of the plan assets of the defined benefit pension and other post-employment benefit plans is as follows:

	Registered	Supplemental	Other	Total
As at Dec. 31, 2021	339	14	—	353
Interest on plan assets	9	—	—	9
Net loss on plan assets	(55)	—	—	(55)
Contributions[(1)]	38	6	—	44
Benefits paid	(57)	(5)	—	(62)
Administration expenses	(1)	—	—	(1)
Change in foreign exchange rates	1	—	—	1
As at Dec. 31, 2022	274	15	—	289
Interest on plan assets	**13**	**1**	**—**	**14**
Net return on plan assets	**15**	**(1)**	**—**	**14**
Contributions[(2)]	**5**	**6**	**2**	**13**
Benefits paid	**(36)**	**(6)**	**(2)**	**(44)**
Administration expenses	**(1)**	**—**	**—**	**(1)**
Change in foreign exchange rates	**(1)**	**—**	**—**	**(1)**
As at Dec. 31, 2023	**269**	**15**	**—**	**284**

(1) The Company made a voluntary contribution of $35 million to further improve the funded status of the Sunhills Mining Ltd. Pension Plan for the Highvale mine. The contribution reduces the amount of the Company's future funding obligations, including amounts secured by the letters of credit.

(2) The Company made a voluntary contribution of $4 million to further improve the funded status of the US Defined Benefit Pension Plan for the Centralia thermal facility.

The fair value of the Company's defined benefit plan assets by major category is as follows:

As at Dec. 31, 2023	Level I	Level II	Level III	Total
Equity securities				
Canadian	—	12	—	12
US	—	6	—	6
International	—	86	—	86
Private	—	—	1	1
Bonds				
A - AAA	—	30	62	92
BBB	1	5	10	16
Below BBB	—	—	4	4
Loans(1)	—	2	—	2
Alternative funds(2)	—	—	44	44
Money market and cash and cash equivalents	2	19	—	21
Total	3	160	121	284

(1) Includes A credit rating loans of $1 million.

(2) Alternative funds include investments in infrastructure and real estate funds.

Dec. 31, 2022(1)	Level I	Level II	Level III	Total
Equity securities				
Canadian	—	18	—	18
US	—	17	—	17
International	—	79	—	79
Private	—	—	1	1
Bonds				
A - AAA	—	27	61	88
BBB	1	6	12	19
Below BBB	—	—	6	6
Loans(2)	—	2	—	2
Alternative funds(3)	—	—	39	39
Money market and cash and cash equivalents	—	20	—	20
Total	1	169	119	289

(1) The fair value level classifications of certain mutual fund investments has been revised for consistency with 2023 classifications.

(2) Includes A credit rating loans of $1 million and BBB credit rating loans of $1 million.

(3) Alternative funds include investments in infrastructure and real estate funds.

Plan assets do not include any common shares of the Company at Dec. 31, 2023 and Dec. 31, 2022.

E. Defined Benefit Obligation

The present value of the obligation for the defined benefit pension and other post-employment benefit plans is as follows:

	Registered	Supplemental	Other	Total
Present value of defined benefit obligation as at Dec. 31, 2021	469	101	23	593
Current service cost	1	1	—	2
Interest cost	13	3	—	16
Benefits paid	(57)	(5)	1	(61)
Actuarial gain arising from financial assumptions	(83)	(22)	(5)	(110)
Actuarial gain arising from experience adjustments	1	7	(2)	6
Change in foreign exchange rates	1	—	—	1
Present value of defined benefit obligation as at Dec. 31, 2022	345	85	17	447
Current service cost	**1**	**1**	**—**	**2**
Interest cost	**16**	**4**	**1**	**21**
Benefits paid	**(36)**	**(6)**	**(2)**	**(44)**
Actuarial loss arising from demographic assumptions	**1**	**—**	**—**	**1**
Actuarial loss arising from financial assumptions	**12**	**4**	**1**	**17**
Actuarial loss arising from experience adjustments	**2**	**1**	**—**	**3**
Change in foreign exchange rates	**(1)**	**—**	**—**	**(1)**
Present value of defined benefit obligation as at Dec. 31, 2023	**340**	**89**	**17**	**446**

(1) The weighted average duration of the defined benefit plan obligation as at Dec. 31, 2023, is 10.4 years.

F. Contributions

The expected employer contributions for 2024 for the defined benefit pension and other post-employment benefit plans are as follows:

	Registered	Supplemental	Other	Total
Expected employer contributions	**3**	**5**	**1**	**9**

G. Assumptions

The significant actuarial assumptions used in measuring the Company's defined benefit obligation for the defined benefit pension and other post-employment benefit plans are as follows:

	2023			2022		
As at Dec. 31 (per cent)	**Registered**	**Supplemental**	**Other**	**Registered**	**Supplemental**	**Other**
Accrued benefit obligation						
Discount rate	**4.6**	**4.6**	**4.7**	4.7	5.0	5.0
Rate of compensation increase	**2.9**	**3.0**	**—**	2.6	3.0	—
Assumed health-care cost trend rate						
Health-care cost escalation(1)(3)	**—**	**—**	**6.8**	—	—	7.1
Dental-care cost escalation	**—**	**—**	**4.2**	—	—	4.2
Benefit cost for the year						
Discount rate	**5.0**	**5.0**	**5.0**	2.8	2.8	2.7
Rate of compensation increase	**2.7**	**3.0**	**—**	2.9	3.0	—
Assumed health-care cost trend rate						
Health-care cost escalation(2)(4)	**—**	**—**	**7.1**	—	—	6.8
Dental-care cost escalation	**—**	**—**	**4.7**	—	—	4.7

(1) 2023 Post- and pre-65 rates: decreasing gradually to 4.5 per cent by 2033 and remaining at that level thereafter for the US and decreasing gradually by 0.3 per cent per year to 4.5 per cent in 2030 for Canada.

(2) 2023 Post- and pre-65 rates: decreasing gradually to 4.5 per cent by 2032 and remaining at that level thereafter for the US and decreasing gradually by 0.3 per cent per year to 4.5 per cent in 2030 for Canada.

(3) 2022 Post- and pre-65 rates: decreasing gradually to 4.5 per cent by 2032 and remaining at that level thereafter for the US and decreasing gradually by 0.3 per cent per year to 4.5 per cent in 2030 for Canada.

(4) 2022 Post- and pre-65 rates: decreasing gradually to 4.5 per cent by 2031 and remaining at that level thereafter for the US and decreasing gradually by 0.3 per cent per year to 4.5 per cent in 2030 for Canada.

H. Sensitivity Analysis

The following table outlines the estimated increase in the net defined benefit obligation assuming certain changes in key assumptions:

	Canadian plans			US plans
As at Dec. 31, 2023	**Registered**	**Supplemental**	**Other**	**Pension**
1% decrease in the discount rate	**30**	**10**	**1**	**2**
1% increase in the salary scale	**1**	**—**	**—**	**—**
1% increase in the health-care cost trend rate	**—**	**—**	**1**	**—**
10% improvement in mortality rates	**13**	**3**	**—**	**1**

32. Joint Arrangements

Joint arrangements at Dec. 31, 2023, included the following:

Joint operations	Segment	Ownership (per cent)	Description
Sheerness	Gas	50	Dual-fuel facility in Alberta, of which TA Cogen has a 50 per cent interest, operated by Heartland Generation Ltd., an affiliate of Energy Capital Partners
Goldfields Power	Gas	50	Gas-fired facility in Australia operated by TransAlta
Fort Saskatchewan	Gas	60	Cogeneration facility in Alberta, of which TA Cogen has a 60 per cent interest, operated by TransAlta
Fortescue River Gas Pipeline	Gas	43	Natural gas pipeline in Western Australia, operated by DBP Development Group
McBride Lake	Wind and Solar	50	Wind generation facility in Alberta operated by TransAlta
Soderglen	Wind and Solar	50	Wind generation facility in Alberta operated by TransAlta
Pingston	Hydro	50	Hydro facility in British Columbia operated by TransAlta

Joint venture	Segment	Ownership (per cent)	Description
Skookumchuck	Wind and Solar	49	Wind generation facility in Washington operated by Southern Power
Tent Mountain	Hydro	50	Pumped hydro energy storage development project in Alberta

33. Cash Flow Information

A. Change in Non-Cash Operating Working Capital

Year ended Dec. 31	2023	2022	2021
(Use) source:			
Accounts receivable	**715**	(869)	(28)
Prepaid expenses	**—**	—	9
Income taxes receivable	**27**	(61)	—
Inventory	**(2)**	6	42
Accounts payable, accrued liabilities and provisions	**(550)**	548	153
Income taxes payable	**(66)**	60	(2)
Change in non-cash operating working capital	**124**	(316)	174

B. Changes in Liabilities from Financing Activities

	Balance Dec. 31, 2022	Cash issuances	Repayments and dividends paid[1]	New leases	Dividends declared	Foreign exchange impact	Other	Balance Dec. 31, 2023
Long-term debt and lease liabilities[2]	3,669	39	(220)	5	—	(36)	12	3,469
Exchangeable securities	739	—	—	—	—	—	5	744
Dividends payable (common and preferred)[3]	68	—	(109)	—	116	—	(26)	49
Total liabilities from financing activities	4,476	39	(329)	5	116	(36)	(9)	4,262

(1) Includes a decrease of $164 million related to the repayment of long-term debt, a $46 million net decrease in borrowings under credit facilities and a decrease in finance lease obligations of $10 million.

(2) Includes bank overdraft of $3 million.

(3) Other dividends payable related to payment of TransAlta Renewables' non-controlling interest dividend reflected within distributions paid to subsidiaries of non-controlling interests in the Consolidated Statements of Cash Flows.

	Balance Dec. 31, 2021	Cash issuances[1]	Repayments and dividends paid[2]	New leases	Dividends declared	Foreign exchange impact	Other	Balance Dec. 31, 2022
Long-term debt and lease liabilities[3]	3,267	981	(630)	40	—	39	(28)	3,669
Exchangeable securities	735	—	—	—	—	—	4	739
Dividends payable (common and preferred)	62	—	(97)	—	103	—	—	68
Total liabilities from financing activities	4,064	981	(727)	40	103	39	(24)	4,476

(1) Includes $449 million net increase in borrowings under credit facilities and an increase in issuance of long-term debt of $532 million.

(2) Includes a decrease of $621 million related to the repayment of long-term debt and a decrease in finance lease obligations of $9 million.

(3) Includes bank overdraft of $16 million.

34. Capital

TransAlta's capital is comprised of the following:

As at Dec. 31	2023	2022	Increase/ (decrease)
Long-term debt[1]	3,466	3,653	(187)
Exchangeable securities	744	739	5
Bank overdraft	3	16	(13)
Equity			
Common shares	3,285	2,863	422
Preferred shares	942	942	—
Contributed surplus	41	41	—
Deficit	(2,567)	(2,514)	(53)
Accumulated other comprehensive income (loss)	(164)	(222)	58
Non-controlling interests	127	879	(752)
Less: available cash and cash equivalents[2]	(348)	(1,134)	786
Less: principal portion of restricted cash on TransAlta OCP bonds[3]	(17)	(17)	—
Less: fair value liability (asset) of hedging instruments on long-term debt[4]	5	(3)	8
Total capital	5,517	5,243	274

(1) Includes lease liabilities, amounts outstanding under credit facilities, tax equity liabilities and current portion of long-term debt.

(2) The Company includes available cash and cash equivalents, as a reduction in the calculation of capital, as capital is managed using a net debt position. These funds may be available and used to facilitate repayment of debt.

(3) The Company includes the principal portion of restricted cash on TransAlta OCP bonds as this cash is restricted specifically to repay outstanding debt.

(4) The Company includes the fair value of economic and designated hedging instruments on debt in an asset, or liability, position as a reduction, or increase, in the calculation of capital, as the carrying value of the related debt has either increased, or decreased, due to changes in foreign exchange rates.

The Company's overall capital management strategy and its objectives in managing capital are as follows:

A. Maintain a Strong Financial Position

The Company operates in a long-cycle and capital-intensive commodity business and it is therefore a priority to maintain a strong financial position that enables the Company to access capital markets at reasonable interest rates.

Maintaining a strong balance sheet also allows our commercial team to contract the Company's portfolio with a variety of counterparties on terms and prices that are favourable to the Company's financial results and provides the Company with better access to capital markets through commodity and credit cycles. The Company has an investment grade credit rating from Morningstar DBRS (stable outlook). In 2023, Moody's reaffirmed the Company's long term rating of Ba1 with a stable outlook. Morningstar DBRS reaffirmed the Company's issuer rating and unsecured debt/medium-term notes rating of BBB (low) and the Company's preferred shares rating of Pfd-3 (low), all with stable outlook, and S&P Global Ratings reaffirmed the Company's senior unsecured debt rating and issuer credit rating of BB+ with stable outlook. The Company remains focused on maintaining a strong financial position and cash flow coverage ratios. Credit ratings provide information relating to the Company's financing costs, liquidity and operations and affect the Company's ability to obtain short-term and long-term financing and/or the cost of such financing.

Management routinely monitors forecasted net earnings, cash flows, capital expenditures and scheduled repayment of debt with a goal of meeting the above ratio targets and to meet dividend and PP&E expenditure requirements.

B. Liquidity

For the years ended Dec. 31, 2023 and 2022, cash inflows and outflows are summarized below. The Company manages variations in working capital using existing liquidity under credit facilities to ensure sufficient cash and credit are available to fund operations, pay dividends, distribute payments to subsidiaries' non-controlling interests and invest in PP&E.

Year ended Dec. 31	2023	2022	Increase (decrease)
Cash flow from operating activities	1,464	877	587
Change in non-cash working capital	(124)	316	(440)
Cash flow from operations before changes in working capital	1,340	1,193	147
Dividends paid on common shares	(58)	(54)	(4)
Dividends paid on preferred shares	(51)	(43)	(8)
Distributions paid to subsidiaries' non-controlling interests	(223)	(187)	(36)
Property, plant and equipment expenditures	(875)	(918)	43
Inflow (outflow)	133	(9)	142

TransAlta maintains sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business. At Dec. 31, 2023, $1.4 billion (2022 – $1.0 billion) of the Company's credit facilities were fully available.

From time to time, TransAlta accesses capital markets, as required, to help fund some of these periodic net cash outflows to maintain its available liquidity and maintain its capital structure and credit metrics within targeted ranges.

35. Related-Party Transactions

Details of the Company's principal operating subsidiaries at Dec. 31, 2023, are as follows:

Subsidiary	Country	Ownership (per cent)	Principal activity
TransAlta Generation Partnership	Canada	100	Generation and sale of electricity
TransAlta Cogeneration, L.P.	Canada	50.01	Generation and sale of electricity
TransAlta Centralia Generation, LLC	US	100	Generation and sale of electricity
TransAlta Energy Marketing Corp.	Canada	100	Energy marketing
TransAlta Energy Marketing (U.S.), Inc.	US	100	Energy marketing
TransAlta Energy (Australia), Pty Ltd.	Australia	100	Generation and sale of electricity
TransAlta Renewables Inc.	Canada	100(1)	Generation and sale of electricity

Associate or joint venture	Country	Ownership (per cent)	Principal activity
SP Skookumchuck Investment, LLC	US	49	Generation and sale of electricity

(1) On Oct. 5, 2023, the Company acquired all of the outstanding common shares of TransAlta Renewables not already owned, directly or indirectly, by TransAlta and certain of its affiliates. TransAlta Renewables at Dec. 31, 2023, is a wholly owned subsidiary of the Company (2022 – 60.1 per cent). Refer to Note 4 for more details.

Transactions between the Company and its subsidiaries have been eliminated on consolidation and are not disclosed. Associates and joint ventures have been equity accounted for by the Company.

A. Transactions with Key Management Personnel

TransAlta's key management personnel include the President and Chief Executive Officer ("CEO"), members of the senior management team that report directly to the President and CEO and the members of the Board. Key management personnel compensation is as follows:

Year ended Dec. 31	2023	2022	2021
Total compensation	**21**	23	30
Comprised of:			
Short-term employee benefits	**11**	11	14
Post-employment benefits	**1**	1	1
Termination benefits	**1**	—	—
Share-based payments	**8**	11	15

B. Transactions with Associates

In connection with the exchangeable securities issued to Brookfield, the Investment Agreement entitles Brookfield to nominate two directors to the TransAlta Board. This allows Brookfield to participate in the financial and operating policy decisions of the Company, and as such, they are considered associates of the Company.

In addition to the exchangeable securities disclosed in Note 25, the Company may, in the normal course of operations, enter into transactions on market terms with associates that have been measured at exchange value and recognized in the Consolidated Financial Statements, including power purchase and sale agreements, derivative contracts and asset management fees. Transactions and balances between the Company and associates do not eliminate.

Transactions with Brookfield include the following:

Year ended Dec. 31	2023	2022	2021
Power sales	**135**	127	27
Purchased power	**2**	12	3
Asset management fees paid	**1**	2	2

36. Commitments and Contingencies

In addition to the commitments disclosed elsewhere in the financial statements, the Company has incurred the following contractual commitments, either directly or through its interests in joint operations and joint ventures.

Approximate future payments under these agreements are as follows:

	2024	2025	2026	2027	2028	2029 and thereafter	Total
Natural gas, transportation and other contracts	55	49	50	48	57	436	695
Transmission	9	9	6	4	5	93	126
Coal supply agreements	86	71	—	—	—	—	157
Long-term service agreements	60	57	42	44	37	184	424
Operating leases	3	3	2	2	2	25	37
Growth	47	—	—	—	—	—	47
Total	**260**	**189**	**100**	**98**	**101**	**738**	**1,486**

Commitments

Natural Gas, Transportation and Other Contracts

The Company has fixed price or volume natural gas purchase and transportation contracts. Included in these contracts are 15-year natural gas transportation agreements for a total of up to 400 terajoules ("TJ") per day on a firm basis, ending in 2036 to 2038 and eight-year natural gas transportation agreements for 75 TJ per day related to the Sheerness facility ending in 2030 to 2031.

Transmission

The Company has several agreements to purchase transmission network capacity in the Pacific Northwest. Provided certain conditions for delivering the service are met, the Company is committed to the transmission at the supplier’s tariff rate whether it is awarded immediately or delivered in the future after additional facilities are constructed.

Coal Supply Agreements

Various coal supply and associated rail transport contracts are in place to provide coal for use in production at the Centralia thermal facility. The coal supply agreements allow TransAlta to take delivery of coal at fixed volumes with dates extending to 2025.

Long-Term Service Agreements

TransAlta has various service agreements in place, primarily for inspections, repairs and maintenance that may be required on natural gas facilities, equipment for gas and turbines at various wind facilities.

Operating Leases

Operating leases include lease commitments not recognized under IFRS 16 and lease commitments that have not yet commenced, mainly related to buildings, vehicles and land.

Growth

Commitments for growth include the following projects: Horizon Hill wind project, White Rock wind projects, the Australian capacity and transmission expansions, the Mount Keith 132kV expansion and various other growth projects.

Contingencies

TransAlta is occasionally named as a party in various claims and legal and regulatory proceedings that arise during the normal course of its business. TransAlta reviews each of these claims, including the nature of the claim, the amount in dispute or claimed and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in the Company's favour or that such claims may not have a material adverse effect on TransAlta. Inquiries from regulatory bodies may also arise in the normal course of business, to which the Company responds as required.

The Company conducts internal reviews of its offers and offer behaviour in both the energy and ancillary services markets in Alberta on an ongoing basis and will self-report suspected contraventions or respond to inquiries from regulatory agencies as required. There currently is no certainty that any particular matter will be resolved in the Company's favour or that such matters may not have a material adverse effect on TransAlta.

Brazeau Facility - Well License Applications to Consider Hydraulic Fracturing Activities

The Alberta Energy Regulator ("AER") issued a subsurface order on May 27, 2019, which does not permit any hydraulic fracturing within three kilometres of the Brazeau facility but permits hydraulic fracturing in all formations (except the Duvernay) within three to five kilometres of the Brazeau facility. Subsequently, two oil and gas operators submitted applications to the AER for 10 well licences (which include hydraulic fracturing activities) within three to five kilometres of the Brazeau facility.

The Company's position, based on independent expert analysis commissioned by the Government of Alberta, is that hydraulic fracturing activities within five kilometres of the Brazeau facility pose an unacceptable risk and that the applications should be denied. The regulatory hearing to consider these applications - Proceeding 379 - was adjourned to April 2025. The other parties to the hearing, including the Company, have supported the adjournment.

Brazeau Facility - Claim against the Government of Alberta

On Sept. 9, 2022, the Company filed a Statement of Claim against the Alberta Government in the Alberta Court of King's Bench seeking a declaration that: (a) granting mineral leases within five kilometres of the Brazeau facility is a breach of the 1960 agreement between the Company and the Alberta Government; and (b) the Alberta Government is required to indemnify the Company for any costs or damages that result from the risks of hydraulic fracturing near the Brazeau facility. On Sept. 29, 2022, the Alberta Government filed its Statement of Defence, which asserts, among other things, that the Company: (a) is trying to usurp the jurisdiction of the AER; and (b) is out of time under the Limitations Act (Alberta). The trial was scheduled for two weeks starting Feb. 26, 2024. The parties to the matter, along with Cenovus Energy Inc., sought an adjournment when AER Proceeding 379 was adjourned. The trial is scheduled to resume in February 2025 in the event the parties are unable to resolve the dispute prior to such date.

Garden Plain

Garden Plain I LP, a wholly owned subsidiary of the Company, retained a third-party contractor to construct the Garden Plain wind project near Hanna, Alberta. The contractor experienced scheduling delays, challenges with construction and significant cost overruns, resulting in overdue deadlines, and has asserted a claim for $49 million in damages. The Company disputes this claim in its entirety and asserts a counterclaim. The parties have initiated the dispute resolution procedure, and the arbitration hearing is set down for three weeks starting April 14, 2025.

Hydro Power Purchase Arrangement ("Hydro PPA") Emissions Performance Credits

The Balancing Pool claimed entitlement to 1,750,000 Emission Performance Credits ("EPCs") earned by the Alberta Hydro facilities as a result of TransAlta opting those facilities into the Carbon Competitiveness Incentive Regulation and Technology Innovation and Emissions Reduction Regulation from 2018-2020 inclusive. The EPCs under dispute had no recorded book value as they were internally generated. The Balancing Pool claimed ownership of the EPCs because it believed the change-in-law provisions under the Hydro PPA required the EPCs to be passed through to the Balancing Pool. TransAlta disputed this claim. The parties have reached a confidential settlement and this matter is now resolved.

Sundance A Decommissioning

TransAlta filed an application with the Alberta Utilities Commission seeking payment from the Balancing Pool for TransAlta's decommissioning costs for Sundance A, including its proportionate share of the Highvale mine. The Balancing Pool and Utilities Consumer Advocate are participating as interveners because they take issue with the decommissioning costs claimed by TransAlta. The application is being heard in the first quarter of 2024 with a decision expected to be rendered in the third quarter of 2024.

37. Segment Disclosures

A. Description of Reportable Segments

The Company has six reportable segments as described in Note 1.

The following tables provides each segment's results in the format that the TransAlta's President and Chief Executive Officer (the chief operating decision maker) ("CODM"), reviews the Company's segments to make operating decisions and assess performance. The CODM assesses the performance of the operating segments based on a measure of adjusted EBITDA. This measurement basis represents earnings before income taxes, adjusted for the effects of: depreciation of property, plant and equipment and amortization of intangibles, depreciation of right-of-use assets, finance lease income, unrealized mark-to-market gains or losses, gains and losses related to closed positions effectively settled by offsetting positions with exchanges recorded in the year the positions are settled, unrealized foreign exchange gains or losses on commodity transactions, depreciation on our mining equipment included in fuel and purchased power, interest income recorded on the prepaid funds, items within the Energy Transition segment that may not be reflective of on-going operations including certain costs related to decisions made to accelerate our transition off-coal in Alberta and our planned transition off-coal for Centralia, impairment charges, share of (profit) loss of joint venture and other costs or income adjustments. The tables below show the reconciliation of the total segmented results and adjusted EBITDA to the statement of earnings (loss) reported under IFRS.

For internal reporting purpose, the earnings information from the Company's investment in Skookumchuck has been presented in the Wind and Solar segment on a proportionate basis. Information on a proportionate basis reflects the Company's share of Skookumchuck's statement of earnings on a line-by-line basis. Proportionate financial information is not and is not intended to be, presented in accordance with IFRS. Under IFRS, the investment in Skookumchuck has been accounted for as a joint venture using the equity method.

B. Reported Adjusted Segment Earnings and Segment Assets

I. Reconciliation of Adjusted EBITDA to Earnings (Loss) before Income Tax

Year ended Dec. 31, 2023	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	533	357	1,514	751	220	1	3,376	(21)	—	3,355
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(4)	16	(67)	(5)	23	—	(37)	—	37	—
Realized gain (loss) on closed exchange positions	—	—	10	—	(91)	—	(81)	—	81	—
Decrease in finance lease receivable	—	—	55	—	—	—	55	—	(55)	—
Finance lease income	—	—	12	—	—	—	12	—	(12)	—
Unrealized foreign exchange loss on commodity	—	—	1	—	—	—	1	—	(1)	—
Adjusted revenues	529	373	1,525	746	152	1	3,326	(21)	50	3,355
Fuel and purchased power	19	30	453	557	—	1	1,060	—	—	1,060
Reclassifications and adjustments:										
Australian interest income	—	—	(4)	—	—	—	(4)	—	4	—
Adjusted fuel and purchased power	19	30	449	557	—	1	1,056	—	4	1,060
Carbon compliance	—	—	112	—	—	—	112	—	—	112
Gross margin	510	343	964	189	152	—	2,158	(21)	46	2,183
OM&A	48	80	192	64	43	115	542	(3)	—	539
Taxes, other than income taxes	3	12	11	3	—	1	30	(1)	—	29
Net other operating income	—	(7)	(40)	—	—	—	(47)	—	—	(47)
Reclassifications and adjustments:										
Insurance recovery	—	1	—	—	—	—	1	—	(1)	—
Adjusted net other operating income	—	(6)	(40)	—	—	—	(46)	—	(1)	(47)
Adjusted EBITDA[2]	459	257	801	122	109	(116)	1,632			
Equity income										4
Finance lease income										12
Depreciation and amortization										(621)
Asset impairment reversals										48
Interest income										59
Interest expense										(281)
Foreign exchange loss										(7)
Gain on sale of assets and other										4
Earnings before income taxes										880

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.

(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS.

Year ended Dec. 31, 2022	Hydro	Wind & Solar(1)	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments(1)	Reclass adjustments	IFRS financials
Revenues	606	303	1,209	714	160	(2)	2,990	(14)	—	2,976
Reclassifications and adjustments:										
Unrealized mark-to-market loss	1	104	251	10	12	—	378	—	(378)	—
Realized gain (loss) on closed exchange positions	—	—	(4)	—	47	—	43	—	(43)	—
Decrease in finance lease receivable	—	—	46	—	—	—	46	—	(46)	—
Finance lease income	—	—	19	—	—	—	19	—	(19)	—
Unrealized foreign exchange gain on commodity	—	—	—	—	(1)	—	(1)	—	1	—
Adjusted revenues	607	407	1,521	724	218	(2)	3,475	(14)	(485)	2,976
Fuel and purchased power	22	31	641	566	—	3	1,263	—	—	1,263
Reclassifications and adjustments:										
Australian interest income	—	—	(4)	—	—	—	(4)	—	4	—
Adjusted fuel and purchased power	22	31	637	566	—	3	1,259	—	4	1,263
Carbon compliance	—	1	83	(1)	—	(5)	78	—	—	78
Gross margin	585	375	801	159	218	—	2,138	(14)	(489)	1,635
OM&A	55	68	195	69	35	101	523	(2)	—	521
Taxes, other than income taxes	3	12	15	4	—	1	35	(2)	—	33
Net other operating income	—	(23)	(38)	—	—	—	(61)	3	—	(58)
Reclassifications and adjustments:										
Insurance recovery	—	7	—	—	—	—	7	—	(7)	—
Adjusted net other operating income	—	(16)	(38)	—	—	—	(54)	3	(7)	(58)
Adjusted EBITDA(2)	527	311	629	86	183	(102)	1,634			
Equity income										9
Finance lease income										19
Depreciation and amortization										(599)
Asset impairment charges										(9)
Interest income										24
Interest expense										(286)
Foreign exchange gain										4
Gain on sale of assets and other										52
Earnings before income taxes										353

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.

(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS.

Year ended Dec. 31, 2021	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	383	323	1,109	709	211	4	2,739	(18)	—	2,721
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	25	(40)	19	(38)	—	(34)	—	34	—
Realized gain (loss) on closed exchange positions	—	—	(6)	—	29	—	23	—	(23)	—
Decrease in finance lease receivable	—	—	41	—	—	—	41	—	(41)	—
Finance lease income	—	—	25	—	—	—	25	—	(25)	—
Unrealized foreign exchange gain on commodity	—	—	(3)	—	—	—	(3)	—	3	—
Adjusted revenues	383	348	1,126	728	202	4	2,791	(18)	(52)	2,721
Fuel and purchased power	16	17	457	560	—	4	1,054	—	—	1,054
Reclassifications and adjustments:										
Australian interest income	—	—	(4)	—	—	—	(4)	—	4	—
Mine depreciation	—	—	(79)	(111)	—	—	(190)	—	190	—
Coal inventory writedown	—	—	—	(17)	—	—	(17)	—	17	—
Adjusted fuel and purchased power	16	17	374	432	—	4	843	—	211	1,054
Carbon compliance	—	—	118	60	—	—	178	—	—	178
Gross margin	367	331	634	236	202	—	1,770	(18)	(263)	1,489
OM&A	42	59	175	117	36	84	513	(2)	—	511
Reclassifications and adjustments:										
Parts and materials writedown	—	—	(2)	(26)	—	—	(28)	—	28	—
Curtailment gain	—	—	—	6	—	—	6	—	(6)	—
Adjusted OM&A	42	59	173	97	36	84	491	(2)	22	511
Taxes, other than income taxes	3	10	13	6	—	1	33	(1)	—	32
Net other operating loss (income)	—	—	(40)	48	—	—	8	—	—	8
Reclassifications and adjustments:										
Royalty onerous contract and contract termination penalties	—	—	—	(48)	—	—	(48)	—	48	—
Adjusted net other operating loss (income)	—	—	(40)	—	—	—	(40)	—	48	8
Adjusted EBITDA[2]	322	262	488	133	166	(85)	1,286			
Equity income										9
Finance lease income										25
Depreciation and amortization										(529)
Asset impairment charges										(648)
Interest income										11
Interest expense										(256)
Foreign exchange gain										16
Gain on sale of assets and other										54
Loss before income taxes										(380)

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.

(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS.

II. Selected Consolidated Statements of Financial Position Information

As at As at Dec. 31, 2023	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
PP&E	462	3,360	1,543	251	—	98	5,714
Right-of-use assets	7	94	5	—	—	11	117
Intangible assets	2	141	40	4	5	31	223
Goodwill	258	176	—	—	30	—	464

As at As at Dec. 31, 2022	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
PP&E	437	2,837	1,858	313	—	111	5,556
Right-of-use assets	6	98	6	2	—	14	126
Intangible assets	2	157	49	5	8	31	252
Goodwill	258	176	—	—	30	—	464

III. Selected Consolidated Statements of Cash Flows Information

Additions to non-current assets are as follows:

Year ended Dec. 31, 2023	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Additions to non-current assets:							
PP&E	42	674	89	16	—	54	875
Intangible assets	—	—	—	—	—	13	13

Year ended Dec. 31, 2022	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Additions to non-current assets:							
PP&E	36	745	43	19	—	75	918
Intangible assets	—	19	—	—	3	9	31

Year ended Dec. 31, 2021	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Additions to non-current assets:							
PP&E	29	166	167	90	—	28	480
Intangible assets	—	—	—	1	—	8	9

IV. Depreciation and Amortization on the Consolidated Statements of Cash Flows

The reconciliation between depreciation and amortization reported on the Consolidated Statements of Earnings (Loss) and the Consolidated Statements of Cash Flows is presented below:

Year ended Dec. 31	2023	2022	2021
Depreciation and amortization expense on the Consolidated Statements of Earnings (Loss)	**621**	599	529
Depreciation included in fuel and purchased power (Note 6)	**—**	—	190
Depreciation and amortization on the Consolidated Statements of Cash Flows	**621**	599	719

C. Geographic Information

I. Revenues

Year ended Dec. 31	2023	2022	2021
Canada	**2,218**	1,905	1,854
US	**987**	940	731
Australia	**150**	131	136
Total revenue	**3,355**	2,976	2,721

II. Non-Current Assets

	Property, plant and equipment		Right-of-use assets		Intangible assets		Other assets	
As at Dec. 31	2023	2022	2023	2022	2023	2022	2023	2022
Canada	**3,578**	3,817	**43**	49	**108**	123	**68**	62
US	**1,749**	1,307	**71**	74	**88**	101	**42**	34
Australia	**387**	432	**3**	3	**27**	28	**69**	64
Total	**5,714**	5,556	**117**	126	**223**	252	**179**	160

D. Significant Customer

For the year ended Dec. 31, 2023, sales to the AESO represented 46 per cent of the Company’s total revenue (2022 – sales to the AESO represented 60 per cent of the Company’s total revenue). There were no other companies that accounted for more than 10 per cent of the Company's total revenue.

Eleven-Year Financial and Statistical Summary

(in millions of Canadian dollars, except where noted)

Year ended Dec. 31	2023	2022	2021
Financial Summary			
STATEMENT OF EARNINGS			
Revenues	**3,355**	2,976	2,721
Operating income (loss)	**1,089**	531	(239)
Earnings (loss) before income taxes	**880**	353	(380)
Net earnings (loss) attributable to common shareholders	**644**	4	(576)
STATEMENT OF FINANCIAL POSITION			
Total assets	**8,659**	10,741	9,226
Current portion of long-term debt, net of cash and cash equivalents	**184**	(940)	(103)
Credit facilities, long-term debt and finance lease obligations	**2,934**	3,475	2,423
Exchangeable securities	**744**	739	735
Non-controlling interests	**127**	879	1,011
Preferred shares	**942**	942	942
Equity attributable to common shareholders[1]	**595**	168	640
Principal portion of restricted cash on TransAlta OCP and fair value (asset) liability of hedging instruments on debt[1]	**(12)**	(20)	(19)
Total capital[2]	**5,517**	5,243	5,629
CASH FLOWS			
Cash flow from operating activities	**1,464**	877	1,001
Cash flow from (used in) investing activities	**(814)**	(741)	(472)
COMMON SHARE INFORMATION (per share)			
Net earnings (loss)	**2.33**	0.01	(2.13)
Comparable earnings[1]	**n/a**	n/a	n/a
Dividends declared on common share	**0.22**	0.21	0.19
Book value per common share (at year-end)[1]	**2.16**	0.62	2.37
Market price:			
High	**13.97**	15.28	14.61
Low	**10.02**	10.52	9.57
Close (Toronto Stock Exchange at Dec. 31)	**11.02**	12.11	14.05
RATIOS (percentage except where noted)			
Adjusted net debt to adjusted EBITDA[1,3,4] (times)	**2.5**	2.2	2.2
Return on equity attributable to common shareholders[1]	**84.8**	1.0	(116.6)
Comparable return on equity attributable to common shareholders[1]	**n/a**	n/a	n/a
Return on capital employed[1]	**17.6**	9.2	(4.5)
Comparable return on capital employed[1]	**n/a**	n/a	n/a
Earnings coverage (times)[1]	**4.3**	2.2	(1.0)
Dividend payout ratio based on FFO[1,4]	**4.4**	4.1	5.1
Adjusted EBITDA[1,3,4] (in millions of Canadian dollars)	**1,632**	1,634	1,286
Dividend coverage[1,4] (times)	**24.6**	18.3	23.0
Dividend yield[1]	**2.0**	1.7	1.3
Weighted average common shares for the year (in millions)	**276**	271	271
Common shares outstanding at Dec. 31 (in millions)	**307**	268	271
STATISTICAL SUMMARY			
Number of employees	**1,257**	1,282	1,282
GROSS INSTALLED CAPACITY (MW)[5]			
Energy Transition[7]	**671**	671	1,472
Gas[6,8]	**3,084**	3,084	3,084
Renewables (wind, solar and hydro)	**3,006**	2,828	2,694
Equity investments	**67**	67	67
Total generating capacity	**6,828**	6,650	7,387
Total generation production (GWh)	**22,029**	21,258	22,105

Financial data presented is based on IFRS. Prior year figures that appear within the MD&A have been restated to conform with the current year's presentation. All other prior year figures have not been restated.

(1) These items are not defined and have no standardized meaning under IFRS. Periods for which the non-IFRS measure was not previously disclosed have not been calculated. After 2016, comparable earnings measures are no longer being calculated or reported on.

2020	2019	2018	2017	2016	2015	2014	2013
2,101	2,347	2,249	2,307	2,397	2,267	2,623	2,292
(99)	335	160	138	478	148	442	195
(303)	193	(96)	(54)	314	221	239	(12)
(336)	52	(248)	(190)	117	(24)	141	(71)
9,747	9,508	9,428	10,304	10,996	10,947	9,833	9,624
(598)	102	59	433	334	33	708	175
3,256	2,699	3,119	2,960	3,722	4,408	3,305	4,130
730	326	—	—	—	—	—	—
1,084	1,101	1,137	1,059	1,152	1,029	594	517
942	942	942	942	942	942	942	781
1,410	2,019	2,055	2,384	2,569	2,419	2,342	2,125
(13)	(17)	(10)	(30)	(163)	(190)	(96)	(16)
6,811	7,172	7,275	7,748	8,556	8,641	7,795	7,712
702	849	820	626	744	432	796	765
(687)	(512)	(394)	87	(327)	(573)	(292)	(703)
(1.22)	0.18	(0.86)	(0.66)	0.41	(0.09)	0.52	(0.27)
n/a	n/a	n/a	n/a	0.13	(0.17)	0.25	0.31
0.22	0.12	0.20	0.16	0.3	0.72	0.83	1.16
5.13	7.14	7.16	8.28	8.92	8.52	8.52	7.92
11.23	10.14	7.90	8.50	7.54	12.34	14.94	16.86
5.32	5.50	5.44	6.88	3.76	4.13	9.81	12.91
9.67	9.28	5.59	7.45	7.43	4.91	10.52	13.48
4.0	3.9	3.6	3.6	3.8	5.4	4.2	4.6
(30.3)	3.3	(15.8)	(10.0)	5.4	(1.2)	6.3	(3.2)
n/a	n/a	n/a	n/a	1.7	(2.3)	3.0	3.7
(1.5)	4.1	0.7	2.1	5.3	4.6	5.8	2.8
n/a	n/a	n/a	n/a	4.4	3.0	5.1	5.2
(0.5)	1.5	0.2	0.6	1.7	1.5	1.7	0.8
7.0	6.6	6.1	4.3	8.1	30.0	26.4	43.1
917	984	1,123	1,062	1,144	867	1,036	1,023
15.6	18.6	18.3	14.1	11.1	3.3	5.7	6.3
1.7	1.7	2.9	2.1	4.0	14.7	7.9	8.6
275	283	287	288	288	280	273	264
270	277	285	288	288	284	275	268
1,476	1,543	1,883	2,228	2,341	2,380	2,786	2,772
2,548	2,915	3,147	3,707	3,707	3,708	3,693	3,693
3,082	3,049	2,819	2,827	2,906	2,823	2,949	3,197
2,498	2,421	2,308	2,289	2,334	2,350	2,204	2,202
67	—	—	—	—	—	—	396
8,265	8,385	8,273	8,823	8,947	8,881	8,846	9,488
24,980	29,071	28,409	36,900	38,157	40,673	45,002	42,482

(2) Total capital for 2013 and 2014 has been revised to align with the 2015 calculation methodology.

(3) In 2022, the adjusted EBITDA composition was amended to include the impact of closed exchange positions that are effectively settled by offsetting positions with the same counterparty to reflect the performance of the assets and the Energy Marketing segment in the period in which the transactions occur. Therefore, the Company has applied this composition to 2022, 2021 and 2020 only. In 2019 and onwards adjusted EBITDA was adjusted to exclude the impact of unrealized mark-to-market gains or losses. 2018 and 2017 amounts were revised.

(4) 2016 and 2015 amounts were revised due to other revisions to EBITDA or FFO measures in the MD&A.

(5) 2012 to 2020 are gross installed capacity, which reflects the basis of underlying results. Prior year figures are as previously reported.

(6) Includes finance lease receivables.

(7) In 2021, Gas was adjusted to include the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal. Prior year figures were revised.

(8) In 2021, Energy Transition was adjusted to include the segments previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal. Prior year figures were revised.

Ratio Formulas

Adjusted net debt to Adjusted EBITDA = long-term debt and lease liabilities including current portion + exchangeable securities + fair value (asset) liability of hedging instruments on debt + 50 per cent issued preferred shares and exchangeable preferred shares - cash and cash equivalents - principal portion of TransAlta OCP restricted cash / Adjusted EBITDA - PPA termination payments

Return on equity attributable to common shareholders = net earnings (loss) attributable to common shareholders excluding gain on discontinued operations or earnings on a comparable basis / equity attributable to common shareholders excluding AOCI

Return on capital employed = earnings (loss) before income taxes + net interest expense - net earnings (loss) attributable to non-controlling interests / total capital - AOCI

Earnings coverage = earnings (loss) before income taxes + net interest expense / 50 per cent dividends paid on preferred shares + interest on debt - interest income

Dividend payout ratio based on FFO = common share dividends paid / FFO - 50 per cent dividends paid on preferred shares

Dividend coverage = FFO - cash dividends paid on preferred shares + change in non-cash operating working capital balances / cash dividends paid on common shares

Dividend yield = dividends paid per common share / current year's closing price

Plant Summary

As at Dec. 31, 2023	Facility	Nameplate capacity (MW)[1]	Consolidated interest	Gross installed capacity[1]	Ownership (%)	Net capacity ownership interest (MW)[1]	Region	Revenue source	Contract expiry date
Hydro	Barrier, AB	13	100 %	13	100 %	13	Western Canada	Merchant	—
24 facilities	Bearspaw, AB	17	100 %	17	100 %	17	Western Canada	Merchant	—
	Belly River, AB	3	100 %	3	100 %	3	Western Canada	Merchant	—
	Bighorn, AB	120	100 %	120	100 %	120	Western Canada	Merchant	—
	Brazeau, AB	355	100 %	355	100 %	355	Western Canada	Merchant	—
	Cascade, AB	36	100 %	36	100 %	36	Western Canada	Merchant	—
	Ghost, AB	54	100 %	54	100 %	54	Western Canada	Merchant	—
	Horseshoe, AB	14	100 %	14	100 %	14	Western Canada	Merchant	—
	Interlakes, AB	5	100 %	5	100 %	5	Western Canada	Merchant	—
	Kananaskis, AB	19	100 %	19	100 %	19	Western Canada	Merchant	—
	Pocaterra, AB	15	100 %	15	100 %	15	Western Canada	Merchant	—
	Rundle, AB	50	100 %	50	100 %	50	Western Canada	Merchant	—
	Spray, AB	112	100 %	112	100 %	112	Western Canada	Merchant	—
	St. Mary, AB	2	100 %	2	100 %	2	Western Canada	Merchant	—
	Taylor, AB	13	100 %	13	100 %	13	Western Canada	Merchant	—
	Three Sisters, AB	3	100 %	3	100 %	3	Western Canada	Merchant	—
	Waterton, AB	3	100 %	3	100 %	3	Western Canada	Merchant	—
	Akolkolex, BC	10	100 %	10	100 %	10	Western Canada	LTC[2]	2046
	Bone Creek, BC	19	100 %	19	100 %	19	Western Canada	LTC	2031
	Pingston, BC	45	50 %	23	100 %	23	Western Canada	LTC	2023
	Upper Mamquam, BC	25	100 %	25	100 %	25	Western Canada	LTC[12]	2025
	Misema, ON	3	100 %	3	100 %	3	Eastern Canada	LTC	2027
	Moose Rapids, ON	1	100 %	1	100 %	1	Eastern Canada	LTC	2030
	Ragged Chute, ON	7	100 %	7	100 %	7	Eastern Canada	LTC	2029
Total Hydro		944		922		922			
Wind &	Ardenville, AB	69	100 %	69	100 %	69	Western Canada	Merchant	—
Battery Storage	Blue Trail and Macleod Flats, AB	69	100 %	69	100 %	69	Western Canada	Merchant	—
29 facilities	Castle River, AB[3]	44	100 %	44	100 %	44	Western Canada	Merchant	—
	Cowley North, AB	20	100 %	20	100 %	20	Western Canada	Merchant	—
	Garden Plain, AB	130	100 %	130	100 %	130	Western Canada	LTC	2034-2041
	McBride Lake, AB	75	50 %	38	100 %	38	Western Canada	LTC	2024
	Oldman, AB	4	100 %	4	100 %	4	Western Canada	Merchant	—
	Sinnott, AB	7	100 %	7	100 %	7	Western Canada	Merchant	—
	Soderglen, AB	71	50 %	36	100 %	36	Western Canada	Merchant	—
	Summerview 1, AB	68	100 %	68	100 %	68	Western Canada	Merchant	—
	Summerview 2, AB	66	100 %	66	100 %	66	Western Canada	Merchant	—
	WindCharger battery storage, AB	10	100 %	10	100 %	10	Western Canada	Merchant	—
	Windrise, AB	206	100 %	206	100 %	206	Western Canada	LTC	2041
	Kent Breeze, ON	20	100 %	20	100 %	20	Eastern Canada	LTC	2031
	Melancthon, ON[4]	200	100 %	200	100 %	200	Eastern Canada	LTC	2028-2031
	Wolfe Island, ON	198	100 %	198	100 %	198	Eastern Canada	LTC	2029
	Kent Hills, NB[5]	167	100 %	167	83 %	139	Eastern Canada	LTC	2045
	Le Nordais, QC	98	100 %	98	100 %	98	Eastern Canada	LTC	2033
	New Richmond, QC	68	100 %	68	100 %	68	Eastern Canada	LTC	2033

Plant Summary

As at Dec. 31, 2023	Facility	Nameplate capacity (MW)[1]	Consolidated interest	Gross installed capacity[1]	Ownership (%)	Net capacity ownership interest (MW)[1]	Region	Revenue source	Contract expiry date
	Antrim, NH	29	100 %	29	100 %	29	United States	LTC	2039
	Big Level, PA	90	100 %	90	100 %	90	United States	LTC	2034
	Lakeswind, MN	50	100 %	50	100 %	50	United States	LTC	2034
	Wyoming Wind, WY	140	100 %	140	100 %	140	United States	LTC	2028
	Skookumchuck, WA	137	49 %	67	100 %	67	United States	LTC	2040
	Northern Goldfields Battery, WA[8]	10	100 %	10	100 %	10	Australia	LTC	2038
Total Wind		2046		1,904		1,876			
Solar	Mass Solar, MA[6]	21	100 %	21	100 %	21	United States	LTC	2032-2045
4 facilities	North Carolina Solar, NC[7]	122	100 %	122	100 %	122	United States	LTC	2033
	Northern Goldfields, WA[8]	38	100 %	38	100 %	38	Australia	LTC	2038
Total Solar		181		181		181			
Gas	Fort Saskatchewan, AB	118	60 %	71	50 %	35	Western Canada	LTC/Merchant	2029
17 facilities	Keephills 2, AB	395	100 %	395	100 %	395	Western Canada	Merchant	—
	Keephills 3, AB	463	100 %	463	100 %	463	Western Canada	Merchant	—
	Poplar Creek, AB[9]	230	100 %	230	100 %	230	Western Canada	LTC	2030
	Sheerness, AB[4]	800	50 %	400	50 %	200	Western Canada	Merchant	—
	Sundance 6, AB	401	100 %	401	100 %	401	Western Canada	Merchant	—
	Ottawa, ON	74	100 %	74	50 %	37	Eastern Canada	LTC/ Merchant	2033
	Sarnia, ON	499	100 %	499	100 %	499	Eastern Canada	LTC	2031
	Windsor, ON	72	100 %	72	50 %	36	Eastern Canada	LTC/ Merchant	2031
	Ada, MI	29	100 %	29	100 %	29	United States	LTC	2026
	Fortescue River Gas Pipeline, WA	N/A	100 %	N/A	100 %	N/A	Australia	LTC	2035
	Parkeston, WA[10]	110	50 %	55	100 %	55	Australia	LTC/Merchant	2026
	Southern Cross, WA[11]	245	100 %	245	100 %	245	Australia	LTC	2038
	South Hedland, WA[12]	150	100 %	150	100 %	150	Australia	LTC	2042
Total Gas		3586		3,084		2,775			
Energy Transition	Centralia, WA	670	100 %	670	100 %	670	United States	LTC/ Merchant	2025[13]
2 facilities	Skookumchuck, WA	1	100 %	1	100 %	1	United States	LTC	2025
Total Energy Transition		671		671		671			
Total		7,428		6,761		6,425			

(1) MW are rounded to the nearest whole number; columns may not add due to rounding. The gross installed capacity reflects the basis of consolidation of underlying assets owned, net capacity ownership interest deducts capacity attributable to non-controlling interest in these assets and is calculated after consolidation of underlying assets.
(2) Long-term Contract.
(3) Includes seven individual turbines at other locations.
(4) Comprised of two facilities.
(5) Comprised of three facilities.
(6) Comprised of four ground-mounted sites and four roof-top sites.
(7) Comprised of 20 sites.
(8) Comprises multiple facilities.
(9) The Poplar Creek plant is operated by Suncor and ownership of the facility will transfer to Suncor in 2030.
(10) The Parkeston facility is contracted to October 2023 with early termination options that begin in 2021.
(11) Comprised of four facilities. Does not include Northern Goldfields facilities that re in the Wind and Solar segment.
(12) The South Hedland facility is contracted with Fortescue Metals Group Ltd. ("FMG") and Horizon Power.
(13) Contract is in place until 2025; however, Centralia Unit 1 was retired from service effective Dec. 31, 2020, and capacity decreased to 670 MW on Jan. 1, 2021.

Sustainability Performance Indicators

Corporate Statistics

Environment, Health and Safety ("EHS") Management Systems	2023	2022	2021
EHS management system audits[1]	**5**	4	4
Health and Safety compliance audits[2]	**3**	9	11
Total EHS audits	**8**	13	15

Environmental Performance[3]	2023	2022	2021
Resource or energy use[4]			
Coal combustion (tonnes)	**2,492,000**	2,181,000	4,094,000
Natural gas combustion (GJ)	**123,067,000**	130,023,000	106,768,000
Diesel combustion (L)	**6,950,000**	6,706,000	7,596,000
Gasoline consumption: vehicle (L)	**610,000**	609,000	864,000
Diesel consumption: vehicle (L)	**2,324,000**	3,275,000	6,705,000
Propane consumption: vehicle (L)	**12,000**	12,000	6,000
Electricity: building operations (MWh)	**126,000**	152,000	174,000
Natural gas: building operations (GJ)	**89,000**	35,000	119,000
Propane: building operations (L)	**110,000**	169,000	189,000
Kerosene: building operations (L)	**0**	3,000	65,000
Total resource or energy use (GJ)	**197,028,000**	194,954,000	203,716,000
Greenhouse gas emissions[5]			
Carbon dioxide (tonnes CO_2e)	**10,846,000**	10,169,000	12,420,000
Methane (tonnes CO_2e)	**26,000**	24,000	25,000
Nitrous oxide (tonnes CO_2e)	**36,000**	41,000	59,000
Sulphur hexafluoride (tonnes CO_2e)	**80**	150	370
Total scope 1 and 2 greenhouse gas emissions (tonnes CO2e)[6]	**10,908,000**	10,233,000	12,505,000
Greenhouse gas emission intensity (tonnes CO_2e/MWh)[7] √	**0.41**	0.40	0.53
Scope 1 emissions (tonnes CO_2e) √	**10,871,000**	10,179,000	12,447,000
Scope 1 emissions (% of total GHG emissions)	**100**	99	99
Scope 1 emissions reported to national regulatory bodies (%)	**100**	100	100
Scope 2 emissions (tonnes CO_2e) √	**37,000**	54,000	58,000
Scope 2 emissions (% of total GHG emissions)	**0**	1	1
Total greenhouse gas emissions avoided (tonnes CO_2e)[8]	**2,280,000**	2,744,000	2,602,000
Air emissions[9]			
Total sulphur dioxide emissions (tonnes) √	**1,100**	1,200	7,300
Sulphur dioxide emission intensity (kg/MWh) √	**0.04**	0.05	0.31
Total nitrogen oxide emissions (tonnes) √	**11,000**	11,000	15,000
Nitrogen oxide emission intensity (kg/MWh) √	**0.40**	0.43	0.65
Total particulate matter emissions (tonnes) √	**460**	360	2,200
Particulate matter emission intensity (kg/MWh) √	**0.02**	0.02	0.09

Environmental Performance *(continued)*	**2023**	**2022**	**2021**
Total mercury emissions (kilograms)[10] √	**18**	21	41
Mercury emission intensity (mg/MWh)[10] √	**0.67**	0.83	1.72
Water management [11]			
Water withdrawal – water utility/municipality/customer (million m³)	**273**	233	241
Water withdrawal – surface water (million m³)	**0**	0	0
Water withdrawn – all sources (million m³) √	**273**	233	241
Water discharge – all sources (million m³) √	**239**	207	209
Water consumption (million m³) √	**34**	26	32
Water consumption intensity (m³/MWh)[12] √	**1.25**	1.03	1.34
Waste management			
Diverted from Disposal - Non-Hazardous[13]			
Recycled (tonnes)	**2,600**	1,600	4,400
Recycled (L)	**137,000**	2,093,000	1,705,000
Reuse (tonnes)	**457,000**	151,000	176,000
Storage (tonnes)[14]	**1,400**	26,000	31,000
Compost (tonnes)	**1**	0	10
Total non-hazardous waste diverted from disposal (tonnes)	**461,000**	180,000	212,000
Diverted from Disposal - Hazardous[15]			
Recycled (tonnes)	**10**	0	8
Recycled (L)	**18,915,000**	21,019,000	22,837,000
Total hazardous waste diverted from disposal (tonnes)	**17,000**	18,000	20,000
Total waste diverted from disposal (tonnes) √	**478,000**	199,000	232,000
Directed to Disposal - Non-Hazardous[16]			
Landfill (tonnes)	**1,300**	1,800	1,100
Landfill (L)	**45,000**	76,000	55,000
Ash disposal:mine (tonnes)[17]	**0**	2,900	232,000
Ash disposal:lagoon (tonnes)[18]	**0**	0	44,000
Compostable (tonnes)	**0**	0	10
Total non-hazardous waste directed to disposal (tonnes)	**1,300**	4,800	277,000
Directed to Disposal - Hazardous[19]			
Landfill (tonnes)	**0**	80	220
Landfill (L)	**4,600**	52,000	26,000
Total hazardous waste directed to disposal (tonnes)	**10**	130	250
Total waste directed to disposal (tonnes) √	**1,300**	4,900	277,000
Land use and reclamation[20]			
Land used in mining activities – disturbed (cumulative hectares) √	**12,600**	12,600	12,600
Land used in mining activities – reclaimed (cumulative hectares) √	**4,900**	4,800	4,800
Reclamation of land used in mining activities (% of land disturbed) √	**39**	38	38
Land used in mining activities: disturbed minus reclaimed (hectares) √	**7,600**	7,800	7,700
Land used by facilities, offices and equipment (hectares) √	**5,000**	5,000	5,000

Total land use (cumulative hectares) √	**12,700**	12,700	12,700

Environmental Performance *(continued)*	**2023**	**2022**	**2021**
Environmental incidents[21]			
Significant environmental incidents	**0**	0	0
Regulatory non-compliance environmental incidents	**0**	1	2
Total environmental incidents √	**0**	1	2
Environmental enforcement actions[22]	**0**	2	1
Environmental fines ($ thousands)	**0**	35	3
Environmental spills[23]			
Volume of significant environmental spills (m^3)	**0**	246	6
Biodiversity-related incidents[24]			
Critically Endangered	**0**	0	0
Endangered	**0**	0	0
Vulnerable	**0**	0	0
Near threatened	**0**	0	0
Total biodiversity-related incidents	**0**	0	0

Social Performance	**2023**	**2022**	**2021**
Workplace practices			
Employees	**1,257**	1,222	1,282
Number of full-time employees	**1,173**	1,150	1,181
Number of part-time employees	**11**	14	15
Number of contingent employees	**73**	58	86
Employees represented by independent trade union organizations (%)[25]	**30**	31	33
Voluntary employee turnover rate (%)[26]	**5**	9	8
Diversity			
Women in workforce (% of all employees)	**27**	26	24
Women in senior management (%)	**26**	30	38
Women on Board of Directors (%)	**46**	36	42
Health and safety			
Health and safety enforcement actions	**0**	0	0
Health and safety fines ($ thousands)	**0**	0	0
Employee and contractor fatalities √	**0**	0	0
Lost-time injury ("LTI") incidents (absence from work)[27] √	**1**	0	3
Medical aid ("MA") incidents (no absence from work)[28] √	**4**	6	9
Restricted work injury ("RWI") incidents (no absence from work)[29] √	**0**	0	5
Total recordable injuries to employees and contractors √	**5**	6	17
Exposure hours[30]	**3,362,000**	3,058,000	4,134,000
Total Recordable Injury Frequency ("TRIF") (employees and contractors)[31] √	**0.30**	0.39	0.82
Community relations			
Community investments ($ millions)[32]	**3.2**	2.3	3.0

√ 2023 data has been assured to a limited assurance level by Ernst & Young LLP.

Please see "Discussion and Notes on Numbers" for footnote explanations.

Alignment of Sustainability Performance Indicators with Best Practice Sustainability Reporting Frameworks

The following outlines our sustainability or ESG performance indicator alignment with key criteria of GRI and SASB. Internally developed criteria are described in the footnotes to the Sustainability Performance Indicators.

Environment, Health and Safety ("EHS") Management Systems	Alignment with GRI or SASB standards
EHS management system audits	Internally developed criteria
Health and Safety compliance audits	Internally developed criteria
Total EHS audits	

Environmental Performance	Alignment with GRI or SASB standards
Resource or energy use	GRI 302-1
Coal combustion (tonnes)	GRI 302-1
Natural gas combustion (GJ)	GRI 302-1
Diesel combustion (L)	GRI 302-1
Gasoline consumption: vehicle (L)	GRI 302-1
Diesel consumption: vehicle (L)	GRI 302-1
Propane consumption: vehicle (L)	GRI 302-1
Electricity: building operations (MWh)	GRI 302-1
Natural gas: building operations (GJ)	GRI 302-1
Propane: building operations (L)	GRI 302-1
Kerosene: building operations (L)	GRI 302-1
Total resource or energy use (GJ)	GRI 302-1
Greenhouse gas emissions	
Carbon dioxide (tonnes CO_2e)	SASB IF-EU-110a.1
Methane (tonnes CO_2e)	SASB IF-EU-110a.1
Nitrous oxide (tonnes CO_2e)	SASB IF-EU-110a.1
Sulphur hexafluoride (tonnes CO_2e)	SASB IF-EU-110a.1
Total scope 1 and 2 greenhouse gas emissions (tonnes CO_2e)	Internally developed criteria
Greenhouse gas emission intensity (tonnes CO_2e/MWh)	GRI 305-4
Scope 1 emissions (tonnes CO_2e)	SASB IF-EU-110a.1
Scope 1 emissions (% of total GHG emissions)	SASB IF-EU-110a.1
Scope 1 emissions reported to national regulatory bodies (%)	SASB IF-EU-110a.1
Scope 2 emissions (tonnes CO_2e)	GRI 305-2
Scope 2 emissions (% of total GHG emissions)	GRI 305-2
Total greenhouse gas emissions avoided (tonnes CO_2e)	Internally developed criteria
Air emissions	
Total sulphur dioxide emissions (tonnes)	SASB IF-EU-120a.1
Sulphur dioxide emission intensity (kg/MWh)	Internally developed criteria
Total nitrogen oxide emissions (tonnes)	SASB IF-EU-120a.1
Nitrogen oxide emission intensity (kg/MWh)	Internally developed criteria
Total particulate matter emissions (tonnes)	SASB IF-EU-120a.1
Particulate matter emission intensity (kg/MWh)	Internally developed criteria

Environmental Performance *(continued)*	**Alignment with GRI or SASB Standards**
Total mercury emissions (kilograms)	SASB IF-EU-120a.1
Mercury emission intensity (mg/MWh)	Internally developed criteria
Water management	
Water withdrawal – water utility/municipality/customer (million m^3)	SASB IF-EU-140a.1
Water withdrawal – surface water (million m^3)	SASB IF-EU-140a.1
Water withdrawn – all sources (million m^3)	SASB IF-EU-140a.1
Water discharge – all sources (million m^3)	Internally developed criteria
Water consumption (million m^3)	SASB IF-EU-140a.1
Water intensity (m^3/MWh)	Internally developed criteria
Waste management	
Diverted from Disposal - Non-Hazardous	
Recycled (tonnes)	GRI 306-4
Recycled (L)	GRI 306-4
Reuse (tonnes)	GRI 306-4
Storage (tonnes)	GRI 306-4
Total non-hazardous waste diverted from disposal (tonnes)	GRI 306-4
Diverted from Disposal - Hazardous	
Recycled (tonnes)	GRI 306-4
Recycled (L)	GRI 306-4
Total hazardous waste diverted from disposal (tonnes)	GRI 306-4
Total waste diverted from disposal (tonnes)	GRI 306-4
Directed to Disposal - Non-Hazardous	
Landfill (tonnes)	GRI 306-5
Landfill (L)	GRI 306-5
Ash disposal:mine (tonnes)	GRI 306-5
Ash disposal:lagoon (tonnes)	GRI 306-5
Compostable (tonnes)	GRI 306-5
Total non-hazardous waste directed to disposal (tonnes)	GRI 306-5
Directed to Disposal - Hazardous	
Landfill (tonnes)	GRI 306-5
Landfill (L)	GRI 306-5
Total hazardous waste directed to disposal (tonnes)	GRI 306-5
Total waste directed to disposal (tonnes)	GRI 306-5

Environmental Performance *(continued)*	Alignment with GRI or SASB Standards
Land use and reclamation	
Land used in mining activities – disturbed (cumulative hectares)	Internally developed criteria
Land used in mining activities – reclaimed (cumulative hectares)	Internally developed criteria
Reclamation of land used in mining activities (% of land disturbed)	Internally developed criteria
Land used in mining activities: disturbed minus reclaimed (hectares)	Internally developed criteria
Land used by plants, offices and equipment (hectares)	Internally developed criteria
Total land use (cumulative hectares)	Internally developed criteria
Environmental incidents	
Significant environmental incidents	Internally developed criteria
Regulatory non-compliance environmental incidents	GRI 307-1
Total environmental incidents	Internally developed criteria
Environmental enforcement actions	GRI 307-1
Environmental fines ($ thousands)	GRI 307-1
Environmental spills	
Volume of significant spills (m^3)	GRI 306-3
Biodiversity-related incidents	
Critically Endangered	Internally developed criteria
Endangered	Internally developed criteria
Vulnerable	Internally developed criteria
Near threatened	Internally developed criteria
Total biodiversity-related incidents	Internally developed criteria

Social Performance	Alignment with GRI or SASB Standards
Workplace practices	
Employees	GRI 102-7
Number of full-time employees	Internally developed criteria
Number of part-time employees	Internally developed criteria
Number of contingent employees	Internally developed criteria
Employees represented by independent trade union organizations (%)	GRI 102-41
Voluntary employee turnover rate (%)	GRI 401-1
Diversity	
Women in workforce (% of all employees)	GRI 405-1
Women in senior management (%)	GRI 405-1
Women on Board of Directors (%)	GRI 405-1

Health and safety	
Health and safety enforcement actions	Internally developed criteria
Health and safety fines ($ thousands)	Internally developed criteria
Employee and contractor Fatalities	SASB IF-EU-320a.1
Lost-time injury ("LTI") incidents (absence from work)	SASB IF-EU-320a.1
Medical aid ("MA") incidents (no absence from work)	SASB IF-EU-320a.1
Restricted work injury ("RWI") incidents (no absence from work)	SASB IF-EU-320a.1
Total injuries to employees and contractors	SASB IF-EU-320a.1
Exposure hours	SASB IF-EU-320a.1
Total Recordable Injury Frequency ("TRIF") (employees and contractors)	SASB IF-EU-320a.1
Community relations	
Community investments ($ millions)	GRI 203-1

Discussion and Notes on Numbers

TransAlta strives to improve the accuracy and scope of our sustainability performance data. We continually review our processes and controls relating to the measurement and calculation of key sustainability data annually. Several footnotes appear throughout the statistical summary and are intended to provide clarity on specific boundary conditions, changes in methodology and definitions. For questions or clarity on any key performance indicators, please contact us at **sustainability@transalta.com**.

1. EHS management system audits are conducted annually to assesses conformance to our environmental, health and safety management systems.
2. Health and Safety compliance audits are conducted to verify compliance to internal health and safety standards and procedures and defined occupational health and safety regulatory requirements.
3. We have updated some of our historical figures following a review of the data and a revision of our rounding methodology. Data revisions that are significant in magnitude have been discussed below. Historical environmental performance figures have been rounded based on the following methodology: i) All environmental data between 0-100 are rounded to the nearest whole number, 100-1,000 to the nearest 10, 1,000-10,000 to the nearest hundred, and above 10,000 to the nearest thousand; ii) Water data is rounded to the nearest million; iii) Land use data, which is smaller in magnitude compared with other environmental indicators, is rounded to the nearest 100 to represent a more accurate picture of management and progress. Some values may not sum to the indicated total due to rounding.
4. Energy use is calculated and reported from TransAlta-operated facilities, following the same approach we use for GHG emissions reporting, which is the application of an 'Operational Control' boundary as per guidance from the GHG Protocol: A Corporate Accounting and Reporting Standard.
5. GHG emissions are calculated and reported from TransAlta-operated facilities in line with carbon compliance regulations from the geographic jurisdiction where the facility is located. For GHG emissions that are not calculated using jurisdictional carbon compliance guidance, we follow guidance from the GHG Protocol: A Corporate Accounting and Reporting Standard (specifically 'Setting Organizational Boundaries: Operational Control' methodology). As per the operational control methodology, TransAlta reports 100 per cent of GHG emissions from facilities at which we are the operator. GHG emissions include emissions from stationary combustion, transportation use, building use and fugitive emissions. If we were to use a financial boundary, there would be no material impact.

   We report both scope 1 and 2 emissions. We compile our corporate GHG inventory using our business segment GHG calculations. All of our scope 1 emissions (100 per cent) are reported to national regulatory bodies in the country in which we operate. This includes: Australia (National Greenhouse and Energy Reporting), Canada (Greenhouse Gas Reporting Program, NPRI) and the US (EPA). Our scope 1 and 2 emissions use global warming potentials and emissions factors that vary with respect to regional compliance guidance and include IPCC 5th Assessment Report, Canada's GHG Inventory 1990-2019, US EPA eGRID Summary Tables 2019 and Australia NGERS Measurement Determination. An estimate of our scope 3 emissions can be found in our 2023 MD&A.
6. Total GHG emissions or CO_2e emissions is the sum of applicable gases which include carbon dioxide, methane, nitrous oxide and sulphur hexafluoride (SF_6). Consequently, the sum of scope 1 and 2 emissions will equate to gross CO_2e emissions or gross GHG emissions.
7. GHG emission intensity is calculated by dividing total operational emissions by 100 per cent of production (MWh) from operated facilities, irrespective of financial ownership. In 2022, we implemented a different approach to calculate the total production which includes steam generation. As such, the 2021 GHG intensity has been revised to include steam generation.
8. Avoided emission is defined as the emissions that are displaced from the power grid through renewables generation instead of standard consumption via the grid. This is calculated by multiplying the total renewable production with the grid carbon intensity of the jurisdiction it operates in.
9. Air emissions which are applicable to TransAlta's operations are NO_x, SO_2, particulate matter (PM2.5 and PM10) and mercury. The applicable air emissions are calculated and reported from TransAlta-operated facilities, following the same approach we use for GHG emissions reporting, which is the application of an 'Operational Control' boundary as per guidance from the GHG Protocol: A Corporate Accounting and Reporting Standard. Air emissions are expressed in tonnes, except for mercury emissions, which are

represented in kilograms. Particulate matter emissions include both PM2.5 and PM10. Air emission intensities are calculated by dividing total operational emissions by 100 per cent of production (MWh) from operated facilities, irrespective of financial ownership. In 2022, we implemented a different approach to calculate the total production which includes steam generation. As such, the 2021 air emissions intensities have been revised to include steam generation.

10. Mercury emissions have been restated for year 2022 due to conversion errors.

11. Water use is calculated and reported from TransAlta-operated facilities, following the same approach we use for GHG emissions reporting, which is the application of an 'Operational Control' boundary as per guidance from the GHG Protocol: A Corporate Accounting and Reporting Standard. Total water consumed is measured by total water withdrawal minus water discharge, where water withdrawal are sourced from surface water, groundwater, third-party, or non-freshwater, and water discharge refers to the volume of freshwater leaving the organization's boundary and released to surface water, groundwater, or to third parties. Water is used primarily for cooling by our thermal power plants. Evaporative losses from cooling ponds and cooling towers account for the majority of consumptive loss. The water lost to evaporation is not returned directly to the water body, but the water remains in the hydrologic cycle.

12. Water intensity is calculated by dividing total operational water consumption (m^3) by 100 per cent of production (MWh) from operated facilities, irrespective of financial ownership. In 2022, we implemented a different approach to calculate the total production which includes steam generation. As such, the 2021 water consumption intensity has been revised to include steam generation.

13. Non-hazardous waste diverted from disposal includes, but is not limited to, the recycling or reuse of water treatment chemicals, coal refuse (including ash byproducts), metals, paper, cardboard and building materials. We measure and report the total weight of all types of waste generated and use several methods for calculation, including direct measurement of quantity on site, by transporters at the point of shipping or loading (consistent with shipping papers), by waste disposal contractor at the point of waste disposal or by transporters, at the point of shipping or loading, and engineering estimates or process knowledge. The unit measurement for non-hazardous waste diverted from disposal is reported as metric ton.

14. Storage waste is ash product from coal production, which is stored onsite for treatment prior to sales for cement production.

15. Hazardous wastes can be harmful to people, plants, animals or the environment, either in the short or the long term, and TransAlta is required in all of its operating jurisdictions to follow proper procedures for recycling of these materials. We measure and report the total weight of all types of waste generated and use several methods for calculation, including direct measurement of quantity on site, by transporters at the point of shipping or loading (consistent with shipping papers), by waste disposal contractor at the point of waste disposal or by transporters, at the point of shipping or loading, and engineering estimates or process knowledge. The unit measurement for hazardous waste is reported as metric ton.

16. Non-hazardous waste directed to disposal includes, but is not limited to, the disposal of water treatment chemicals, coal refuse (including ash byproducts), metals, paper, cardboard and building materials. We measure and report the total weight of all types of waste generated and use several methods for calculation, including direct measurement of quantity on site, by transporters at the point of shipping or loading (consistent with shipping papers), by waste disposal contractor at the point of waste disposal or by transporters, at the point of shipping or loading, and engineering estimates or process knowledge. The unit measurement for non-hazardous waste diverted from disposal is reported as metric ton.

17. Ash disposal: mine is fly ash and bottom ash from coal production, which is treated and then returned to its original source, the mine, for landfill/disposal. In 2023, we reported zero as we have ceased coal operations in Canada; therefore, we have no ash waste to dispose of.

18. Ash disposal: lagoon is fly ash and bottom ash from Keephills coal production, which is treated and then sent to ash lagoons for disposal. In 2023, we reported zero as we have ceased coal operations in Canada; therefore, we have no ash waste to dispose of.

19. Hazardous wastes can be harmful to people, plants, animals or the environment, either in the short or the long term, and TransAlta is required in all of its operating jurisdictions to follow proper procedures for landfill/recycling of these materials. We measure and report the total weight of all types of waste generated and use several methods for calculation, including direct measurement of quantity on site, by transporters at the point of shipping or loading (consistent with shipping papers), by waste disposal contractor at the point of waste disposal or by transporters, at the point of shipping or loading, and engineering estimates or process knowledge. The unit measurement for hazardous waste is reported as metric ton.

20. Land used in mining activities – disturbed refers to the total active footprint of our mining operations, which includes the cumulative hectares for land cleared of vegetation, soil disturbed, ready for reclamation, soils placed, and permanently reclaimed: (i) Disturbed means soil has been disturbed; (ii) Cleared means vegetation has been removed and soils are intact; (iii) Reclamation means the restoration of disturbed lands to similar pre-development condition, other economically productive use, or natural or semi-natural habitat. Land reclamation refers to the ratio between the land that has been permanently or temporarily reclaimed and the total active footprint of our mining operations. Reclamation is presented as a cumulative number; therefore, the total number of hectares reported from year to year may increase depending on whether reclamation has occurred or whether re-disturbance of previously reclaimed areas was required. Total land use refers to the total active footprint of all our operations or the sum of the land used in mining activities plus land used by plants, offices and equipment.

21. Environmental incidents are separated into two categories: significant environmental incidents (internally defined) and regulatory non-compliance environmental incidents (aligned to GRI 307-1). We define significant environmental incidents as an incident that is internally classified as moderate, significant, major or extreme, that resulted in an impact to the ecosystem that is reversible or irreversible. Factors that impact this classification include mortalities of greater than 0.01 per cent of a given species when compared to the overall population, as well as other relevant qualitative factors. We define regulatory non-compliance environmental incidents as violations or non-compliance to regulations or exceedance of limits in company operating approvals that result in enforcement action including fines or stop work orders that suspend overall facility or site operations, but did not have an impact on the environment. For example, a technical issue with a computer system for gathering real-time data could cause us to be out of compliance with local regulation or our EMS, but there is no direct consequence for the physical environment.

22. Environmental enforcement actions are a violation or non-compliance to regulations or exceedance of limits in company operating approvals that result in an impact on the environment and enforcement action including stop work orders, fines or suspension of operating approvals.

23. Spills generally happen in low environmental impact areas and are almost always contained and fully recovered. It is extremely rare that we experience large spills, which could adversely impact the environment and the Company.

24. Biodiversity incidents are the number of total biodiversity-related incidents that affected habitats and species included on the Red List of the International Union for Conservation of Nature and are classified as near-threatened, vulnerable, endangered and critically endangered.

25. In 2023, TransAlta employed approximately 374 unionized workers working primarily in our operational business units.

26. Voluntary turnover is aligned with our Human Resources voluntary turnover reporting methodology. As per this methodology, voluntary turnover is any full-time, part-time or contingent employee initiated exit, excluding retirement. Summer students and temporary workers are not considered within voluntary turnover. Health and safety enforcement actions are a violation of or non-compliance with regulations or exceedance of limits in company operating approvals that result in enforcement action including stop work orders, fines or suspension of operating approvals.

27. Lost-time injuries ("LTIs") are injuries that resulted in the worker being away from work beyond the day of the injury.

28. Medical aids ("MAs") are injuries that resulted in medical treatment beyond first aid.

29. Restricted work injuries ("RWIs") are injuries that resulted in the worker being unable to perform all normally scheduled and assigned work activities.

30. Exposure hours are total hours worked by all TransAlta employees and contractors, and include full-time, part-time, direct, contract, executive, labour, salary, hourly and seasonal employees in all locations, but exclude prime contractors. Exposure hours have been rounded to the nearest thousand.

31. Total Recordable Injury Frequency ("TRIF") measures restricted work, medical aid and lost-time injuries per 200,000 hours worked. It does not include near miss as per the SASB IF EU 320a.1 criteria.

32. Cumulative of donations and sponsorship totals in the respective calendar year. This investment figure does not include donations from our employees.

Independent Practitioner’s Assurance Report

To Management of TransAlta Corporation

Scope

We have been engaged by TransAlta Corporation (the “Company”, or “TransAlta”) to perform a ‘limited assurance engagement,’ as defined by International Standards on Assurance Engagements, hereafter referred to as the engagement, to report on TransAlta’s performance indicators detailed in the accompanying schedule (the “Subject Matter”) for the year ended December 31, 2023, contained in TransAlta’s 2023 Annual Integrated Report (the “Report”).

Other than as described in the preceding paragraph, which sets out the scope of our engagement, this engagement did not include performing assurance procedures on the remaining information included in the Report, and accordingly, we do not express a conclusion on this information.

Criteria Applied by TransAlta

In preparing the Subject Matter, TransAlta applied relevant guidance contained within the Sustainability Accounting Standards Board (“SASB”) Standards, Global Reporting Initiative (“GRI”) Sustainability Reporting Standards, and internally developed criteria, as detailed in the accompanying Schedule, collectively referred to herein as (the “Criteria”). The internally developed Criteria were specifically designed for the preparation of the Report. As a result, the Subject Matter may not be suitable for another purpose.

TransAlta’s Responsibilities

TransAlta’s management is responsible for selecting the Criteria, and for presenting the Subject Matter in accordance with that Criteria, in all material respects. This responsibility includes establishing and maintaining internal controls, maintaining adequate records and making estimates that are relevant to the preparation of the Subject Matter, such that it is free from material misstatement, whether due to fraud or error.

EY’s Responsibilities

Our responsibility is to express a conclusion on the presentation of the Subject Matter based on the evidence we have obtained.

We conducted our engagement in accordance with *the International Standard for Assurance Engagements (“ISAE”) 3000, Assurance Engagements Other than Audits or Reviews of Historical Financial Information (“ISAE 3000”) and ISAE 3410, Assurance Engagements on Greenhouse Gas Statements (“ISAE 3410”)*. These standards require that we plan and perform our engagement to obtain limited assurance about whether, in all material respects, the Subject Matter is presented in accordance with the Criteria, and to issue a report. The nature, timing and extent of the procedures selected depend on our judgment, including an assessment of the risk of material misstatement, whether due to fraud or error.

We believe that the evidence obtained is sufficient and appropriate to provide a basis for our limited assurance conclusion.

Our Independence and Quality Management

We have complied with the relevant rules of professional conduct / code of ethics applicable to the practice of public accounting and related to assurance engagements, issued by various professional accounting bodies, which are founded on fundamental principles of integrity, objectivity, professional competence and due care, confidentiality and professional behaviour.

Our firm applies Canadian Standard on *Quality Management 1, Quality Management for Firms that Perform Audits or Reviews of Financial Statements, or Other Assurance or Related Services Engagements*, which requires us to design, implement and operate a system of quality management including policies or procedures regarding compliance with ethical requirements, professional standards and applicable legal and regulatory requirements.

Description of Procedures Performed

Procedures performed in a limited assurance engagement vary in nature and timing from, and are less in extent than for, a reasonable assurance engagement. Consequently, the level of assurance obtained in a limited assurance engagement is substantially lower than the assurance that would have been obtained had a reasonable assurance engagement been performed. Our procedures were designed to obtain a limited level of assurance on which to base our conclusion and do not provide all the evidence that would be required to provide a reasonable level of assurance.

Although we considered the effectiveness of management's internal controls when determining the nature and extent of our procedures, our assurance engagement was not designed to provide assurance on internal controls. Our procedures did not include testing controls or performing procedures relating to checking aggregation or calculation of data within IT systems.

A limited assurance engagement consists of making enquiries, primarily of persons responsible for preparing the Subject Matter and related information, and applying analytical and other appropriate procedures.

Our procedures included:

- Conducting interviews with relevant personnel to obtain an understanding of the reporting processes;
- Inquiries of relevant personnel who are responsible for the Subject Matter including, where relevant, observing and inspecting systems and processes for data aggregation and reporting in accordance with the Criteria;
- Assessing the accuracy of data, through analytical procedures and limited reperformance of calculations, where applicable, and tested, on a limited sample basis, underlying source information to support completeness and accuracy of the Subject Matter; and
- Reviewing presentation and disclosure of the Subject Matter in the Report.

We also performed such other procedures as we considered necessary in the circumstances.

Inherent Limitations

The Greenhouse Gas ("GHG") quantification process is subject to scientific uncertainty, which arises because of incomplete scientific knowledge about the measurement of GHGs. Additionally, GHG procedures are subject to estimation (or measurement) uncertainty resulting from the measurement and calculation processes used to quantify emissions within the bounds of existing scientific knowledge.

Non-financial information, such as the Subject Matter, is subject to more inherent limitations than financial information, given the more qualitative characteristics of the subject matter and the methods used for determining such information. The absence of a significant body of established practice on which to draw allows for the selection of different but acceptable evaluation techniques which can result in materially different evaluation and can impact comparability between entities and over time.

Conclusion

Based on our procedures and the evidence obtained, nothing has come to our attention that causes us to believe that the Subject Matter for the year ended December 31, 2023, is not prepared, in all material respects, in accordance with the Criteria.

Ernst & Young LLP

Chartered Professional Accountants

February 22, 2024

Calgary, Canada

Schedule

Our limited assurance engagement was performed on the following Subject Matter for the year ended December 31, 2023:

Performance Indicator	Criteria	Reported Value[1]	Unit of Measure
Greenhouse Gas Emissions			
Scope 1 emissions	SASB IF-EU-110a.1	10,871,000	Tonnes CO_2e
Scope 2 emissions	GRI 305-2	37,000	Tonnes CO_2e
Greenhouse gas emission intensity	GRI 305-4	0.41	Tonnes CO_2e /MWh
Air Emissions			
Total sulphur dioxide emissions	SASB IF-EU-120a.1	1,100	Tonnes
Sulphur dioxide emission intensity	Internally developed criteria[2]	0.04	kg/MWh
Total nitrogen oxide emissions	SASB IF-EU-120a.1	11,000	Tonnes
Nitrogen oxide emission intensity	Internally developed criteria[2]	0.40	kg/MWh
Total particulate matter emissions	SASB IF-EU-120a.1	460	Tonnes
Particulate matter emission intensity	Internally developed criteria[2]	0.02	kg/MWh
Total mercury emissions	SASB IF-EU-120a.1	18	kg
Mercury emission intensity	Internally developed criteria[2]	0.67	mg/MWh
Water Management			
Water withdrawn – all sources	SASB IF-EU-140a.1	273	Million m^3
Water discharge – all sources	Internally developed criteria[2]	239	Million m^3
Water consumption	SASB IF-EU-140a.1	34	Million m^3
Water consumption intensity	Internally developed criteria[2]	1.25	m^3/MWh
Waste Management			
Total waste diverted from disposal	GRI 306-4	478,000	Tonnes
Total waste directed to disposal	GRI 306-5	1,300	Tonnes
Land Use and Reclamation			
Land used in mining activities – disturbed	Internally developed criteria[2]	12,600	Cumulative hectares
Land used in mining activities – reclaimed	Internally developed criteria[2]	4,900	Cumulative hectares
Reclamation of land used in mining activities	Internally developed criteria[2]	39	% of land disturbed

Performance Indicator	Criteria	Reported Value[1]	Unit of Measure
Land used in mining activities: disturbed minus reclaimed	Internally developed criteria[2]	7,600	Hectares
Land used by facilities, offices and equipment	Internally developed criteria[2]	5,000	Hectares
Total land use	Internally developed criteria[2]	12,700	Cumulative hectares
Environmental Incidents			
Total environmental incidents	Internally developed criteria[2]	0	Number
Health and Safety			
Employee and contractor fatalities	SASB IF-EU-320a.1[3]	0	Number
Lost-time injury (LTI) incidents	SASB IF-EU-320a.1[3]	1	Number
Medical aid (MA) incidents	SASB IF-EU-320a.1[3]	4	Number
Restricted work injury (RWI) incidents	SASB IF-EU-320a.1[3]	0	Number
Total recordable injuries to employees and contractors	SASB IF-EU-320a.1[3]	5	Number
Total Recordable Injury Frequency (TRIF) (employees and contractors)	SASB IF-EU-320a.1[3]	0.30	Rate

(1) All figures have been rounded in accordance with footnote 3 in the Sustainability Performance Indicators section of the Report.

(2) As described in the footnotes to the Sustainability Performance Indicators section of the Report.

(3) Other criteria, included in the SASB Disclosure IF-EU-320a.1 (3), near miss frequency rate (NMFR) is excluded from the scope of our limited assurance engagement.

Shareholder Information

Special Services for Registered Shareholders

Service	Description
Direct deposit for dividend payments	Automatically have dividend payments deposited to your bank account
Account consolidations	Eliminate costly duplicate mailings by consolidating account registrations
Address changes and share transfers	Receive tax splits and dividends without the delays resulting from address and ownership changes

Stock Splits and Share Consolidations

Date	Events
May 8, 1980	Stock split
February 1, 1988	Stock split(1)
December 31, 1992	Reorganization — TransAlta Utilities shares exchanged for TransAlta Corporation shares(2) 1:1

The valuation date value of common shares owned on December 31, 1971, adjusted for stock splits, is $4.54 per share.

(1) The adjusted cost base for shares held on January 31, 1988, was reduced by $0.75 per share following the February 1, 1988, share split.

(2) TransAlta Utilities Corporation became a wholly owned subsidiary of TransAlta Corporation as a result of this reorganization.

Dividend Declaration for Common Shares

Dividends are paid quarterly as determined by the Board. Dividends on our common shares are at the discretion of the Board. In determining the payment and level of future dividends, the Board considers our financial performance, results of operations, cash flow and needs with respect to financing our ongoing operations and growth, balanced against returning capital to shareholders. The Board continues to focus on building sustainable earnings and cash flow growth.

Common Share Dividends Declared in 2023

Payment Date	Record Date	Ex-Dividend Date	Dividend
April 1, 2023	March 1, 2023	Feb. 28, 2023	$0.055
July 1, 2023	June 1, 2023	May 31, 2023	$0.055
Oct. 1, 2023	Sept. 1,2023	Aug. 31, 2023	$0.055
Jan. 1, 2024	Dec. 1, 2023	Nov. 30, 2023	$0.055

Submission of Concerns Regarding Accounting or Auditing Matters

TransAlta has adopted a procedure for employees, shareholders or others to report concerns or complaints regarding accounting or other matters on an anonymous, confidential basis to the Audit, Finance and Risk Committee of the Board of Directors. Such submissions may be directed to the Audit, Finance and Risk Committee c/o the Chief Officer, Legal, Regulatory and External Affairs, of the Company.

Dividend Declaration for Preferred Shares

Series A: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $0.71924 per share from and including March 31, 2021, to, but excluding, March 31, 2026.

Series B: Floating cumulative preferential cash dividends are paid quarterly when declared by the Board from and including March 31, 2021, to, but excluding, March 31, 2026.

Series C: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.46352 per share from and including June 30, 2022, to, but excluding, June 30, 2027.

Series D: Floating cumulative preferential cash dividends are paid quarterly when declared by the Board from and including June 30, 2022, to, but excluding, June 30, 2027.

Series E: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.72352 per share from and including September 30, 2022, to, but excluding, September 30, 2027.

Series G: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.247 per share from and including September 30, 2019, to, but excluding, September 30, 2024.

Preferred Share Dividends Declared in 2023

Series A

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2023	March 1, 2023	Feb. 28, 2023	$0.17981
June 30, 2023	June 1, 2023	May 31, 2023	$0.17981
Sept. 30, 2023	Sept. 1, 2023	Aug. 31, 2023	$0.17981
Dec. 31, 2023	Dec. 1, 2023	Nov. 30, 2023	$0.17981
March 31, 2024	March 1, 2024	Feb. 28, 2024	$0.17981

Series B

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2023	March 1, 2023	Feb. 28, 2023	$0.37991
June 30, 2023	June 1, 2023	May 31, 2023	$0.41100
Sept. 30, 2023	Sept. 1, 2023	Aug. 31, 2023	$0.41545
Dec. 31, 2023	Dec. 1, 2023	Nov. 30, 2023	$0.45288
March 31, 2024	March 1, 2024	Feb. 28, 2024	$0.43958

Series C

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2023	March 1, 2023	Feb. 28, 2023	$0.36588
June 30, 2023	June 1, 2023	May 31, 2023	$0.36588
Sept. 30, 2023	Sept. 1, 2023	Aug. 31, 2023	$0.36588
Dec. 31, 2023	Dec. 1, 2023	Nov. 30, 2023	$0.36588
March 31, 2024	March 1, 2024	Feb. 28, 2024	$0.36588

Series D

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2023	March 1, 2023	Feb. 28, 2023	$0.45578
June 30, 2023	June 1, 2023	May 31, 2023	$0.47769
Sept. 30, 2023	Sept. 1, 2023	Aug. 31, 2023	$0.48287
Dec. 31, 2023	Dec. 1, 2023	Nov. 30, 2023	$0.52030
March 31, 2024	March 1, 2024	Feb. 28, 2024	$0.50609

Series E

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2023	March 1, 2023	Feb. 28, 2023	$0.43088
June 30, 2023	June 1, 2023	May 31, 2023	$0.43088
Sept. 30, 2023	Sept. 1, 2023	Aug. 31, 2023	$0.43088
Dec. 31, 2023	Dec. 1, 2023	Nov. 30, 2023	$0.43088
March 31, 2024	March 1, 2024	Feb. 28, 2024	$0.43088

Series G

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2023	March 1, 2023	Feb. 28, 2023	$0.31175
June 30, 2023	June 1, 2023	May 31, 2023	$0.31175
Sept. 30, 2023	Sept. 1, 2023	Aug. 31, 2023	$0.31175
Dec. 31, 2023	Dec. 1, 2023	Nov. 30, 2023	$0.31175
March 31, 2024	March 1, 2024	Feb. 28, 2024	$0.31175

Dividends are paid on the last day of the month in March, June, September and December. When a dividend payment date falls on a weekend or holiday, the payment is made on the following business day. Only dividend payments that have been approved by the Board of Directors are included in this table. The Board of Directors has also declared dividends on the Series I Preferred Shares, which are held by an affiliate of Brookfield Renewable Partners.

Voting Rights

Common shareholders receive one vote for each common share held.

Annual Meeting

The Annual and Special Meeting of Shareholders will be held in a virtual-only meeting format at 11:00 a.m., Mountain standard time, on Thursday, April 25, 2024.

Transfer Agent

Computershare Trust Company of Canada
Suite 800, 324-8th Avenue SW
Calgary, Alberta T2P 2Z2

Phone

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1.800.564.6253 toll-free
Outside North America:
514.982.7555

Fax

North America:
1.888.453.0330 toll-free
Outside North America:
403.267.6529
Website:
www.investorcentre.com

Exchanges

Toronto Stock Exchange (TSX)
New York Stock Exchange (NYSE)

Ticker Symbols

TransAlta Corporation common shares: TSX: TA, NYSE: TAC
TransAlta Corporation preferred shares: TSX: TA.PR.D, TA.PR.E, TA.PR.F, TA.PR.G, TA.PR.H, TA.PR.J

Additional Information

Requests can be directed to:

Investor Relations
TransAlta Corporation

TransAlta Place
Suite 1400, 1100 1st Street SE
Calgary, Alberta T2G 1B1

Phone

North America:
1.800.387.3598 toll-free
Calgary/outside North America:
403.267.2520

Email

investor_relations@transalta.com
Website:
www.transalta.com

Shareholder Highlights

Ten-Year Total Shareholder Return vs. S&P/TSX Composite Index

Year ended Dec. 31 ($)	14	15	16	17	18	19	20	21	22	23
TransAlta	100	51	79	81	62	105	112	165	145	134
S&P/TSX	100	89	104	111	98	117	119	145	132	143

This chart compares what $100 invested in TransAlta and the S&P/TSX Composite Index at the end of 2014 would be worth today, assuming the reinvestment of all dividends.

Source: FactSet

Ten-Year Market Value vs. Book Value

Year ended Dec. 31 ($ per share)	14	15	16	17	18	19	20	21	22	23
Market Value	10.52	4.91	7.43	7.45	5.59	9.28	9.67	14.05	12.11	11.02
Book Value	8.52	8.52	8.92	8.28	7.16	7.14	5.13	2.37	0.62	2.16

Data is from 2014 onwards.

Source: FactSet and TransAlta

Monthly Volume and Market Prices

2023	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Volume (millions)	11	14	14	11	12	12	12	13	14	24	18	14
TSX closing price ($ per share)	12.92	11.06	11.82	12.08	13.08	12.40	13.45	12.97	11.83	10.15	11.04	11.02

Source: FactSet

Return on Common Shareholders' Equity

(%)	14	15	16	17	18	19	20	21	22	23
ROE	6.3	(1.2)	5.4	(10.0)	(15.8)	3.3	(30.3)	(116.6)	1.0	84.8

Source: TransAlta

Corporate Information

Corporate Governance: New York Stock Exchange Disclosure Differences

TransAlta's Corporate Governance Guidelines, Board Charter, Committee Charters, position descriptions for the Chair and President & CEO, and codes of business conduct and ethics are available on our website at www.transalta.com. Also available on our website is a summary of the significant ways in which TransAlta's corporate governance practices differ from those required to be followed by US domestic companies under the New York Stock Exchange's listing standards. Currently there are no significant differences between our governance practices and those of the New York Stock Exchange.

Ethics Helpline

The Board of Directors has established an anonymous and confidential Internet portal, email address and toll-free telephone number for employees, contractors, shareholders and other stakeholders who wish to report accounting irregularities, ethical violations or any other matters they wish to bring to the attention of the Board.

The Ethics Helpline phone number is **1.855.374.3801** (US/Canada) and **1.800.40.5308** (Australia)

Internet portal: **transalta.com/ethics-helpline**

Email: **ethics_helpline@transalta.com**

Any communications to the Board of Directors may also be sent to **corporate_secretary@transalta.com**.

TransAlta Corporate Officers

John Kousinioris
President and Chief Executive Officer

Todd Stack
Executive Vice President, Finance and Chief Financial Officer

Jane Fedoretz
Executive Vice President, People, Culture and Chief Administrative Officer

Kerry O'Reilly Wilks
Executive Vice President, Growth and Energy Marketing

Chris Fralick
Executive Vice President, Generation

Blain van Melle
Executive Vice President, Commercial and Customer Relations

Aron Willis
Executive Vice President, Project Delivery and Construction

David Little
Senior Vice President, Growth

Brent Ward
Senior Vice President, M&A, Strategy and Treasurer

Michelle Cameron
Vice President and Corporate Controller

Scott Jeffers
Acting Executive Vice President, Legal and Corporate Secretary

Glossary of Key Terms

Adjusted Availability

Availability is adjusted when economic conditions exist, such that planned routine and major maintenance activities are scheduled to minimize expenditures. In high price environments, actual outage schedules would change to accelerate the generating unit's return to service.

Alberta Electric System Operator (AESO)

Alberta Electric System Operator; the independent system operator and regulatory authority for the Alberta Interconnected Electric System.

Alberta Hydro Assets

The Company's hydroelectric assets owned through a wholly owned subsidiary, TA Alberta Hydro LP. These assets are located in Alberta and consist of the Barrier, Bearspaw, Bighorn, Brazeau, Cascade, Ghost, Horseshoe, Interlakes, Kananaskis, Pocaterra, Rundle, Spray and Three Sisters hydro facilities.

Alberta Thermal

The business segment previously disclosed as Canadian Coal has been renamed to reflect the ongoing conversion of the boilers to burn gas in place of coal. The segment includes the legacy and converted generating units at our Sundance and Keephills sites and includes the Highvale mine.

Ancillary Services

As defined by the Electric Utilities Act, ancillary services are those services required to ensure that the interconnected electric system is operated in a manner that provides a satisfactory level of service with acceptable levels of voltage and frequency.

AUC

Alberta Utilities Commission (AUC).

Availability

A measure of time, expressed as a percentage of continuous operation - 24 hours a day, 365 days a year - that a generating unit is capable of generating electricity, regardless of whether or not it is actually generating electricity.

Balancing Pool

The Balancing Pool was established in 1999 by the Government of Alberta to help manage the transition to competition in Alberta's electric industry. Their current obligations and responsibilities are governed by the *Electric Utilities Act* (effective June 1, 2003) and the Balancing Pool Regulation. For more information go to **www.balancingpool.ca**.

Boiler

A device for generating steam for power, processing or heating purposes, or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes of the boiler shell.

Capacity

The rated, continuous load-carrying ability of generation equipment, expressed in megawatts.

Cash-Generating Unit (CGU)

A cash-generating unit is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets, and goodwill is allocated to each CGU or group of CGUs that is expected to benefit from the synergies of the acquisition from which the goodwill arose.

Centralia

The business segment previously disclosed as US Coal has been renamed to reflect the sole asset.

Cogeneration

A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam) used for industrial, commercial, heating or cooling purposes.

Disclosure Controls and Procedures (DC&P)

Refers to controls and other procedures designed to ensure that information required to be disclosed in the reports filed by the Company or submitted under securities legislation is recorded, processed, summarized and reported within the time frame specified in applicable securities legislation. DC&P include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Company in its reports that it files or submits under applicable securities legislation is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Dispatch Optimization

Purchasing power to fulfil contractual obligations, when economical.

Emissions Performance Standards ("EPS")

Under the Government of Ontario, emission performance standards establish greenhouse gas (GHG) emissions limits for covered facilities.

Environmental Management Systems (EMS)

A set of processes and practices that enable an organization to reduce its environmental impacts and increase its operating efficiency.

EPCs

Emission Performance Credits.

Force Majeure

Literally means “greater force.” A clause in a contract that excuses a party from liability if some unforeseen event beyond the control of that party prevents it from performing its obligations under the contract.

Free Cash Flow (FCF)

Amount of cash generated by the Company through its operations (cash from operations) minus the funds used by the Company for the purchase, improvement or maintenance of the long-term assets to improve the efficiency or capacity of the Company (capital expenditures).

Funds from Operations (FFO)

Calculated as cash flow from operating activities before changes in working capital and is adjusted for transactions and amounts that the Company believes are not representative of ongoing cash flows from operations.

Gigajoule (GJ)

A metric unit of energy commonly used in the energy industry. One GJ equals 947,817 British thermal units (Btu). One GJ is also equal to 277.8 kilowatt hours.

Gigawatt (GW)

A measure of electric power equal to 1,000 megawatts.

Gigawatt Hour (GWh)

A measure of electricity consumption equivalent to the use of 1,000 megawatts of power over a period of one hour.

Global Reporting Initiative (GRI)

The world's most widely used sustainability standards. An independent, international organization that helps businesses and other organizations take responsibility for their impacts by providing them with the global common language to communicate those impacts.

Greenhouse Gas (GHG)

A gas that has the potential to retain heat in the atmosphere, including water vapour, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons and perfluorocarbons.

ICFR

Internal control over financial reporting.

IFRS

International Financial Reporting Standards.

Megawatt (MW)

A measure of electric power equal to 1,000,000 watts.

Megawatt Hour (MWh)

A measure of electricity consumption equivalent to the use of 1,000,000 watts of power over a period of one hour.

Merchant

A term used to describe assets that are not contracted and are exposed to market pricing.

NCIB

Normal Course Issuer Bid.

OM&A

Operations, maintenance and administration costs.

Other Hydro Assets

The Company's hydroelectric assets located in British Columbia and Ontario and assets owned by TransAlta Renewables, which include the Taylor, Belly River, Waterton, St. Mary, Upper Mamquam, Pingston, Bone Creek, Akolkolex, Ragged Chute, Misema, Galetta, Appleton and Moose Rapids facilities.

Planned Outage

Periodic planned shutdown of a generating unit for major maintenance and repairs. Duration is normally in weeks. The time is measured from unit shutdown to putting the unit back online.

Power Purchase Agreement (PPA)

A long-term agreement established by regulation for the sale of electric energy to PPA buyers.

PP&E

Property, plant and equipment.

Renewable Energy Credits (REC)

All right, title, interest and benefit in and to any credit, reduction right, offset, allocated pollution right, emission reduction allowance, renewable attribute or other proprietary or contractual right, whether or not tradable, resulting from the actual or assumed displacement or reduction of emissions, or other environmental characteristic, from the production of one MWh of electrical energy from a facility utilizing certified renewable energy technology.

Renewable Power

Power generated from renewable terrestrial mechanisms including wind, geothermal, solar and biomass with regeneration.

Spark Spread

A measure of gross margin per megawatt (sales price less cost of natural gas).

Sustainability Accounting Standards Board (SASB)

Connects businesses and investors on the financial impacts of sustainability. SASB Standards identify the subset of ESG issues most relevant to financial performance in each of the 77 covered industries.

Task Force on Climate-Related Financial Disclosures (TCFD)

Designed to solicit consistent, decision-useful, forward-looking information on the material

financial impacts on climate-related risks and opportunities, including those related to the global transition to a low-carbon economy. They are adopted by all organizations with public debt or equity in G20 jurisdictions for use in mainstream financial filings.

Total Recordable Injury Frequency (TRIF)

Tracks the number of more serious injuries and excludes minor first aids, relative to exposure hours worked.

Turbine

A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse and reaction or a mixture of the two.

Turnaround

Periodic planned shutdown of a generating unit for major maintenance and repairs. Duration is normally in weeks. The time is measured from unit shutdown to putting the unit back online.

Unplanned Outage

The shutdown of a generating unit due to an unanticipated breakdown.

Value at Risk (VaR)

A measure used to manage exposure to market risk from commodity risk management activities.

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