Accelerating Clean

TransAlta

2021 Integrated Report

About This Report

Welcome to TransAlta's seventh consecutive Integrated Report, which combines our financial and sustainability goals and results. This is an industry-leading practice and TransAlta is one of only a few companies to do this in North America. We believe sustainability performance should be evaluated, managed and communicated alongside our financial performance to demonstrate the impact on financial, environmental and societal value.

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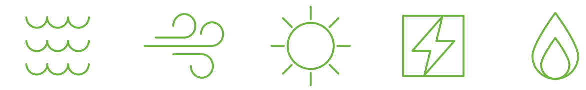
John Kousinioris
President and Chief Executive Officer

In 2021, we completed our **final conversion from coal to gas in Alberta**. Our entire Canadian fleet is now off coal — **nine years ahead** of the Alberta government's mandated end to coal-fired generation in 2030. This achievement marks an important milestone in our journey toward the ultimate **decarbonization of our company.**

John P. Dielwart
Chair of the Board of Directors

Dear TransAlta Investors



Writing my inaugural letter to shareholders, I am extremely proud to report outstanding results in 2021.

These results came from a combination of strong performance from our operations, optimization and trading teams, and a relentless focus on execution from our growth and development teams during another challenging COVID-19 year. Our success is the product of the individual efforts of each TransAlta employee. It has been an honour to lead an organization comprised of talented people with a profound commitment to delivering exceptional results while adhering to our core values of safety, innovation, sustainability, respect, and integrity.

Our financial results in 2021 exceeded any year in our recent history. TransAlta delivered record free cash flow of $562 million, $2.07 per share, with all business segments contributing to our success. Our performance enabled us to announce an 11 per cent increase in our annual dividend to $0.20 per share. This increase reflects our success in 2021 and our confidence in TransAlta's capacity to execute our growth plan and optimize returns from our existing assets.

2021 Achievements

Executing a Strategy Built for Energy Transition

In September 2021, we announced our Clean Electricity Growth Plan, which will guide TransAlta's path to building an additional 2 GW of clean generation by 2025. This strategy is rooted in two core convictions. First, that the electricity sector will lead a global energy transition toward net-zero leading to significant demand for zero-emissions generation. Second, a successful energy transition will rely on an optimized set of existing assets delivering reliable and competitively priced electricity while markets integrate renewables and new technologies.

A growing number of customers are looking for partners capable of helping them achieve ambitious decarbonization targets. One of TransAlta's core competitive advantages is our differentiated ability to meet their needs with customer-centric energy solutions integrating a strong balance sheet, exceptional ability to execute growth projects, leading operations expertise, and energy trading and optimization capabilities that maximize reliability and returns. Our 2021 performance reflects strength across all of these differentiating factors.

Strong Balance Sheet

In 2021, we continued to enhance the financial strength of our company. We have reduced our senior debt by approximately 31 per cent over the past two years. With $2.2 billion of liquidity, including almost $950 million in cash and cash equivalents, we are very well positioned to successfully deliver our growth strategy and generate greater opportunities to create value for our shareholders.

Successful Execution

In a COVID-19 year that tested our project execution capabilities, our teams showed resilience and an ability to advance growth projects, and our decarbonization efforts, within our stated budgets and timelines:

Pembina Pipelines and Garden Plain Wind Project

In May 2021, we signed an 18-year, 100 MW PPA with Pembina Pipelines for the electricity and environmental credits generated by our 130 MW Garden Plain Project near Hanna, Alberta. Construction began during the fall of 2021 and commercial operation is anticipated in late 2022. Total construction capital for the project is estimated at approximately $190-$200 million. The remaining 30 MW from Garden Plan will either be contracted or offered into the Alberta wholesale merchant market. This project is a great example of the ESG solutions that we can offer our customers to decarbonize their businesses.

BHP Nickel West and Northern Goldfields Solar and Battery Storage Project

In July 2021, we announced that we had reached an agreement to provide BHP Nickel West with renewable electricity supported by battery storage to support its mining operations in Mount Keith and Leinster, Western Australia.

Construction of the 48 MW Northern Goldfields Solar and Storage Project has commenced with targeted completion of the project during the second half of 2022. Total construction capital for the project is estimated to be approximately AU$69-$73 million. The project will lower emissions from BHP's operations at Northern Goldfields by an estimated 12 per cent.

North Carolina Solar Acquisition

In August 2021, we acquired a 122 MW portfolio of 20 solar sites in North Carolina for US$99 million and the assumption of existing tax equity obligations. The acquisition adds Duke Energy as a customer, helps us expand our solar generation portfolio in an important region of the United States, broadens our renewables capabilities, and deepens our development and operating experience with solar generation.

Windrise

On November 10, our 206 MW Windrise wind facility achieved commercial operation. The capital cost of Windrise was approximately $285 million and production from the facility is fully contracted through a 20-year offtake agreement with the Alberta Electric System Operator (AESO) under its Renewable Electricity Program. The largest of our 10 operating wind facilities in Alberta, Windrise is located roughly 20 km southwest of Claresholm, Alberta. Windrise will provide $20-$22 million of average annual EBITDA with long-term, contracted cash-flows with a high investment grade counterparty, extending the contracted duration of our cashflows.

White Rock East and West

In December 2021, we announced that we had signed a long-term PPA with a new customer with an AA credit rating from S&P Global Ratings for 300 MW of capacity from our White Rock East and White Rock West wind projects in Caddo County, Oklahoma, our largest project to date in the United States. Under the terms of the PPA, our customer will receive both renewable electricity and environmental attributes. Construction is expected to begin in late 2022 with a target commercial operation date in the second half of 2023. Total construction capital is estimated at approximately US$460-$470 million. The project is expected to generate total annual EBITDA of approximately US$42-$46 million including production tax credits. White Rock is further validation of our customer-centric strategy to respond to the net-zero energy transition by developing an inventory of quality projects to meet the growing demand for contracted renewable electricity.

Coal to Gas Transition

In 2021, we also completed coal-to-gas conversions at Sundance Unit 6, and Keephills Units 2 and 3 in Alberta. These projects allow these facilities to continue meeting the needs of Alberta consumers by providing reliable, competitively priced electricity with an approximately 50 per cent lower emissions profile. This step change in emissions contributes to our goal of achieving a 75 per cent emissions reduction over 2015 levels by 2026, a leading target for our sector.

Executing projects and closing acquisitions can be difficult at the best of times, and 2021 had its challenges. However, I was consistently impressed at the innovation and flexibility shown by our project teams in the face of constantly evolving COVID-19 guidelines and successive COVID-19 waves. In rising to the challenges, our teams showed our customer-centric approach positioning TransAlta as a reliable partner with deep commitment to successful execution.

President's Message

The projects, acquisitions, and transitions completed and announced in 2021, which spanned all of our operating geographies, achieved 30 per cent of our 2 GW growth target and reduced our GHG emissions 24 per cent year-over-year, outstanding results for the first year of our five-year Clean Electricity Growth Plan.

Leading Operations and Optimization

Another of TransAlta's key competitive advantages is our ability to operate and optimize our existing assets, especially in the Alberta market. While our growth, project, and M&A teams added to our fleet of high-quality assets, we also saw strong performance from our teams tasked with operating and maximizing returns from our diverse existing fleet. In 2021, our new team charged with optimizing our Alberta merchant market performance had an excellent first year, delivering $864 million of gross margin from a mix of hydro, wind, gas, coal, and energy storage.

Our energy trading desk also delivered very strong results in 2021 showing the value of our expertise across markets and energy types.

Underpinning our success are operations professionals focused on safely operating and maintaining our facilities. These teams also managed through COVID-19, completing turnarounds, enhancing the performance of individual facilities, and troubleshooting unforeseen circumstances with care and diligence. Our financial results would have been impossible without the availability delivered by the industry-leading performance of our operations teams.

The combined operational and optimization expertise of these teams adds important differentiating strengths as we compete to deliver contracted energy solutions for our customers and strong returns from our merchant assets.

Moving into the second year of our Clean Electricity Growth Plan, we see a dynamic and constantly growing opportunity set. TransAlta's 2021 accomplishments in growth, project execution, operations, trading, and optimization tangibly showed why we are well positioned to grasp further opportunities in 2022 and beyond.

An Organization Prepared to Thrive

As an incoming CEO, I am frequently asked about my priorities for evolving our organization. Delivering on our growth strategy and optimizing the performance of our existing assets constitute the core of our strategy, but within these goals, we are also working to enhance TransAlta's culture and resilience. I want to highlight two areas of focus in 2021. First, is a strong focus on multiple dimensions of our safety culture and second is preparing for disruption.

Progress on Our Safety and Cultural Journey

In an organization like ours, consideration of safety starts with a focus on the physical safety of our employees. As you will see in our Annual Report, our safety performance, while strong compared to our peers, remained relatively static in 2021. This was not the outcome that we were seeking and, as a result, we committed to enhancing our safety culture through new training and approaches across the company.

As a part of our broader focus on organizational culture, we are also working to promote greater team collaboration and effectiveness to deliver company results. We want our employees to have candid discussions, raise difficult issues, and bold ideas that challenge the status quo. The energy transition will require consistent innovation to meet our customers' evolving needs. Innovation starts with one employee speaking up. At TransAlta, I want all of our employees to be grounded by our company core values and speak up with confidence.

We also want our employees to feel safe bringing their whole selves to work. Our Equity, Diversity, and Inclusion strategy, entering its second year, is focused on celebrating multiple dimensions of diversity. It is obvious that companies need to leverage talent from everywhere and barriers to inclusion are deeply counterproductive to long-term performance. I am grateful to our ED&I Council for leading the way in identifying and breaking down remaining barriers and, in doing so, making TransAlta a better workplace and a more competitive organization.

Preparing for Disruption

Few companies reach 110 years of age. In guiding TransAlta to 110, my predecessors weathered many types of disruption, and our current executive team continually scans for emerging trends that might impact our business.

This year, I want to share my thoughts on two critical sources of potential disruption. The first is perennial — technology change, the second is particularly acute in our sector — policy change.

As part of our Clean Electricity Growth Plan, we have established a new technology team tasked with building our expertise in emerging technologies. Getting to net-zero will require the wide-spread development and deployment of game-changing technologies. It is critical that TransAlta has a deep understanding of the potential of these technologies to build and protect our business. Our work in this area led to an early stage investment in Ekona Power Inc. (announced in February 2022) and we will continue to make strategic investments moving forward. In doing so, we will strengthen our position as a customer-centric clean energy partner and mitigate technology risks to our merchant assets.

2021 saw the Government of Canada commit to a net-zero electricity grid by 2035, a key priority as we must electrify in order to achieve our economy-wide decarbonization objectives. This is just one example of the policy change that we are seeing in all of our markets. As governments develop the policies and regulations required to deliver a net-zero transition, we can expect disruption that brings new opportunities and risks in the global electricity sector.

In one way, TransAlta continues to respond to this disruption as we always have; by providing reasoned policy advice and thinking deeply about solutions that work from a reliability, cost, and emissions reduction perspective. I am pleased to report that we have maintained our position as a credible voice in climate policy conversations. In 2021, we enhanced our Alberta modeling capacity as part of our commitment to fleet optimization. By doing so, we also augmented our ability to provide actionable advice to governments throughout their policy development processes. We remain confident that TransAlta's fleet is well-configured for a lower emissions future and 2021 saw us enhancing our analytical capabilities to support our long-term view and prepare us for the important policy conversations ahead.

Our Clean Electricity Growth Plan will also substantially reduce our exposure to policy disruption. Perhaps the most important decision made in the first few months of my tenure as CEO was the suspension of the Sundance 5 natural gas repowering project. Subsequent policy developments have only reinforced my confidence in that decision. Our growth plan focuses on renewables, which insulates our financial performance from carbon policy risks, and long-term contracting, which reduces our exposure to the impact of policy changes in merchant markets.

A decade into TransAlta's second century of operations, I am pleased with the progress that we have made in 2021 as we evolved our organizational culture, enhanced our foresight regarding potential disruption, and continued to manage and mitigate key risks.

Building from Strength to Strength

I am acutely aware that the success we delivered in 2021 builds on the work and the foresight of many TransAlta employees, both current and former.

The past year saw us complete our off-coal transition in Canada. The conclusion of our coal operations at Highvale, Sundance, and Keephills led to the departure of a significant number of our employees, many of whom dedicated decades of their working lives to the reliable operations of our coal plants since they were first commissioned in the 1970s. Throughout this difficult transition, the men and women most affected exhibited incredible dedication, commitment, professionalism, and excellence. They are an example to all of us and their extraordinary effort, and many contributions, will always remain part of the fabric and memory of our company.

We also owe a debt of thanks to Dawn Farrell, who stepped down as President and CEO of TransAlta on March 31, 2021. I worked closely with Dawn for almost a decade and admired and learned from her leadership, integrity, and commitment to, and vision for, TransAlta. She navigated our company through a period of transformative change, establishing TransAlta as a leading clean electricity-focused company spanning three countries, competitively positioned for the opportunities of the net-zero economy we are all working to achieve. Her legacy will endure.

As we report on a tremendously successful year and look forward to the future, I also want to express my sincere thanks to our Board of Directors for their support, guidance, and wisdom. They are committed to our company, our values, and our mission to deliver the clean electricity our world will need in the future.

To our investors, we thank you for your continuing commitment to TransAlta. This year was truly an exceptional year for our company, and I feel honoured to lead a team of people who work tirelessly to deliver outstanding performance. I am pleased to report that there is every reason to believe that our success will continue in 2022.

John Kousinioris
President and Chief Executive Officer
February 23, 2022

Dear Fellow Shareholders

I have had the great honour and privilege to serve as the Chair of the Board of Directors of TransAlta Corporation since the second quarter of 2020, just as COVID-19 was emerging and changing how we all work and live.

Throughout 2021, the pandemic continued to impose challenges to our operations, especially as we were completing our off-coal initiative in Canada, which required hundreds of contractors to work alongside our operations staff for extended periods of time. I am happy to report that this significant initiative was completed essentially on time, on budget and with minimal COVID-related incidents. This is a tribute to TransAlta's head office and field leadership teams' ability to adapt on the fly as new COVID-related protocols had to be introduced as the virus evolved. If that wasn't challenge enough, our principal market, Alberta, with the expiry of the Alberta power purchase arrangements transitioned to a fully merchant market on January 1, 2021, which dramatically altered how we operate our generating facilities. Once again, your leadership teams performed brilliantly in this new market, so much so that 2021 was a record year financially.

During 2021, we also transitioned our CEO role from Dawn Farrell to John Kousinioris on April 1, 2021. I want to acknowledge Dawn's exceptional contributions to TransAlta during her long tenure with TransAlta and in particular this past decade as President and CEO. Dawn's highly accomplished 35-year career in electricity provided her with the breadth of experience and wisdom needed to successfully guide the company through our transition off coal. Dawn transformed our core business and thoroughly prepared the organization and her successor to be successful in her absence. She was instrumental in ensuring a smooth transition for John to *hit the ground running*. Dawn's contributions have set TransAlta up to be in a significantly stronger position today relative to when she took on the CEO role. Her presence and contributions will truly be missed.

When incoming President and CEO John Kousinioris assumed the helm in April, the strategic course for the company was well established and understood. He very effectively executed this strategy throughout the remainder of 2021 in spite of the headwinds being experienced by the evolution of the pandemic. As a result, TransAlta is expanding its role as a leading provider of renewable electricity generation and emissions-reduction solutions for our customers.

We also owe a debt of thanks to retiring Directors Yakout Mansour and Georgia Nelson for their long-term service and significant contributions to the company. I would also like to acknowledge the retirement of Richard Legault. While his tenure was shorter than that of Yakout and Georgia, he also was a significant contributor to the Board. The upside to Board renewal is that we are able to restructure the Board with the skills needed for the future direction of the company. I am excited about the quality of the new Board members that we were able to attract in 2021 – each of whom has already made meaningful contributions to the corporation. The four new members who joined the Board of Directors are Laura Folse, Thomas O'Flynn, James Reid, and Sarah Slusser.

As the pandemic evolved and restrictions/regulations changed, management's response to the pandemic was, in my opinion, truly industry leading. Management at TransAlta was often contacted by their industry peers seeking advice on how to roll out similar programs at their companies. The virus has continued to impact our workforce and our business, but our team delivered excellent performance while most employees worked remotely. I am hopeful 2022 will find us returning to our offices, and I am excited to see what additional success the year will bring. Returning to in-person work will refresh our culture and reinvigorate collaboration among our teams, helping to carry our success in 2021 forward.

I continue to be proud of the way the Board and management worked together to manage the pandemic response throughout 2021. As all corporations did, we needed to adopt new ways of collaborating virtually and learned how to work together from afar. I am also proud of the entire organization for their continued effort, flexibility, adaptability and resilience through the year. While some teams were able to return to the office periodically, depending on their jurisdiction's restrictions at a given time, most spent 2021 working remotely. Our teams demonstrated that they could rise to the challenge to deliver this year's outstanding results under a distributed working model of working remotely. The TransAlta team met or exceeded nearly all of their key objectives and targets.

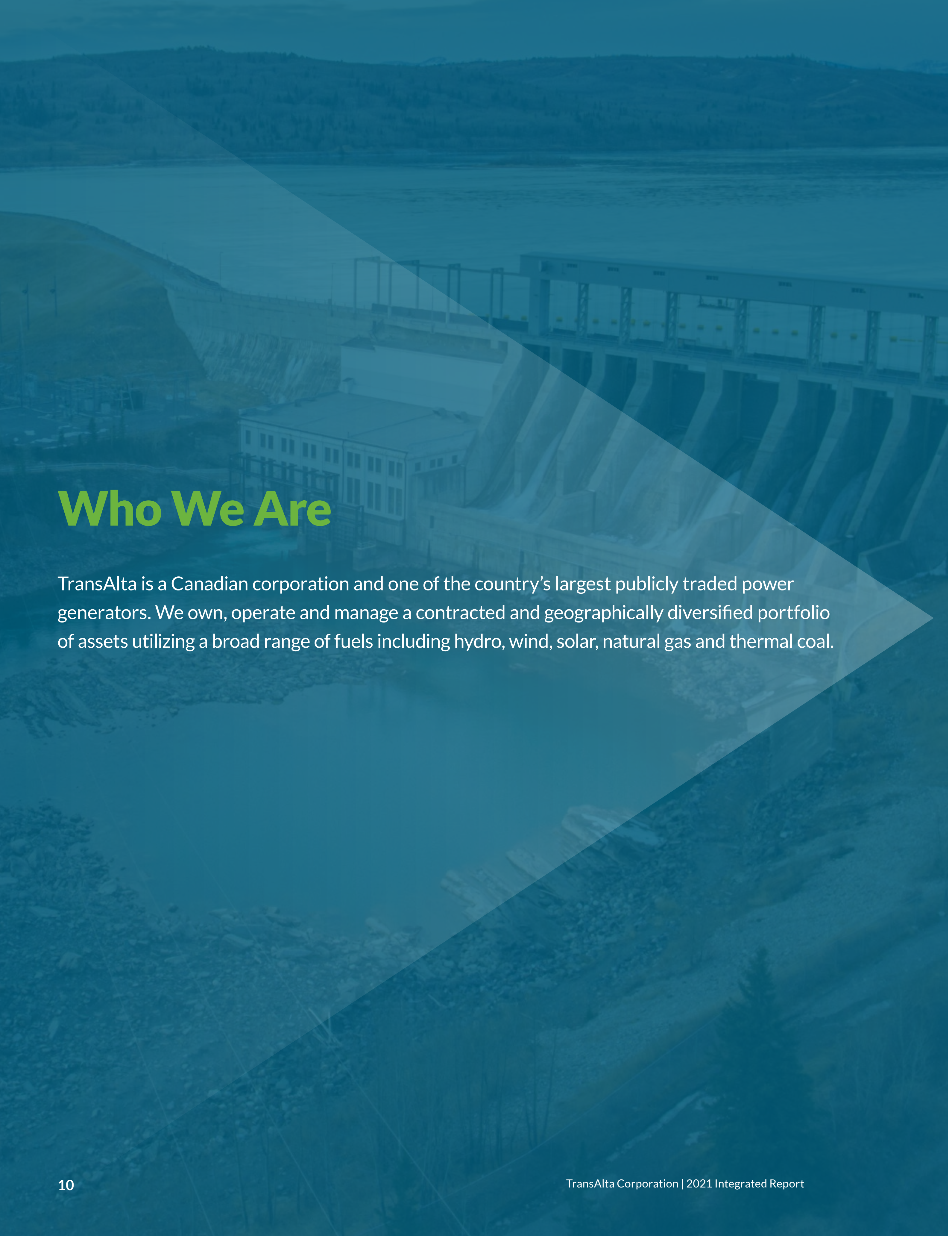
We are also proud to once again be recognized as a leader in corporate governance, having jumped in our ranking on the Globe and Mail's Board Games from 14 in 2020 to 6 in 2021. This recognition is a testament to the Company's performance as an industry leader in corporate governance and disclosure. We are outperforming our peers on this ranking and I could not be prouder of that. The importance of diversity both in the organization and on the Board is well understood within TransAlta and we are steadfast in our commitment to the goals that we have set surrounding Equity, Diversity and Inclusion within the organization.

As previously mentioned, in 2021 we completed our final conversion from coal to gas in Alberta. Our entire Canadian fleet is now off coal – nine years ahead of the Alberta government's mandated end to coal-fired generation in 2030. This achievement marks an important milestone in our journey toward the ultimate decarbonization of our company, with an ambition of carbon neutrality by 2050, and an earnest contribution to Canada's emissions-reduction goals. But the move away from coal is important for another reason; it is critical to our core strategy of delivering low-cost, reliable and low-emissions power to customers. We acknowledge, however, that the transition away from coal has significant adverse consequences for a material number of our employees. The employees to whom we bid farewell at the end of 2021 deserve the highest praise for the professionalism and dedication on display throughout this transition. We are grateful for their service, not only through the transition, but also throughout the decades of plant operations to which they dedicated their working lives. Their contributions were a critical component to our success since first firing on coal in 1970.

In September, at our Investor Day, we debuted our Clean Electricity Growth Plan that will guide the Company's strategy to 2025 and beyond. TransAlta has a diversified fleet with over 3 GW of development in our growth pipeline. We are a clean power leader with a strong and dedicated focus on ESG. We are also in the strongest financial position that we have been in for decades. We are on an exciting trajectory of growth and will transition from 35 per cent renewables currently to a target of 70 per cent in the next five years.

As we look forward to 2022, we hope to see more of our friends, colleagues and peers in person. Our organization is innovative, nimble and bold in delivering on its mandate as an independent power producer. On behalf of your Board, I can assure you that TransAlta remains dedicated to accelerated renewables growth and customer-centric project development. We are on a strong and strategic path forward to deliver the clean electricity the world needs today and into the future.

John P. Dielwart
Chair of the Board of Directors
February 23, 2022



Who We Are

TransAlta is a Canadian corporation and one of the country's largest publicly traded power generators. We own, operate and manage a contracted and geographically diversified portfolio of assets utilizing a broad range of fuels including hydro, wind, solar, natural gas and thermal coal.

Our Corporate Culture: Heart of Our Success

Our vision is to be a leader in clean electricity — committed to a sustainable future.

Our mission is to provide safe, low-cost and reliable clean electricity.

Our Values
Safety
Innovation
Sustainability
Respect
Integrity

Our values define our corporate culture. They reflect our skills and mindset, while providing a framework for everything we do, guiding both internal conduct and external activities.

Our People: Our Greatest Asset

Our employees are central to value creation. Our corporate culture has evolved and adapted throughout our more than 110-year heritage. Through corporate initiatives and support throughout all levels of leadership, we encourage our employees to maximize their potential.

Health & Safety ✓	Employee Retention & Recognition ✓
The safety of our people, communities and the environment is one of our core values. Each year we invest significant resources into improving our safety performance, including positively enhancing our safety culture.	We strive to be an employer of choice through our total rewards programs, which include various incentive plans designed to align performance with our annual and longer-term targets, as determined annually by the Board.
Equity, Diversity & Inclusion ✓	**Talent & Employee Development ✓**
We believe a strong focus on Equity, Diversity & Inclusion will drive performance in innovation, improve service to our customers and positively impact the communities that we all live in.	Investing in our employee development enhances employees' skills and improves productivity and engagement. This contributes to a strong corporate culture that provides value for TransAlta.

▶ *See pages **M96 to M100**, Building a Diverse and Inclusive Workforce, for further details.*

Our Generation Fleet

We operate a diverse fleet of electrical power generation assets in Canada, the United States and Australia consisting of hydro, wind, solar, battery storage, gas and energy transition facilities. The energy transition business segment was created as a result of the transition away from coal as a fuel source.





Hydro

- Low variable cost
- Water is a finite, storable resource
- Optimization of flows
- Super-peak capacity, must-run, ancillary market products

Wind & Solar

- Low variable cost
- Price-taker
- Not correlated to event/weather-driven pricing

Battery Storage

- Fast frequency response
- Time-shift wind and hydro output
- Serves ancillary markets

Gas & Energy Transition

- Low capital investment
- Baseload and peak capacity
- More competitive than new combined-cycle gas turbine plants

TransAlta is 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.

▶ *See pages **M4 to M11** for details on our Portfolio of Assets.*

Geographic Breakdown: International Reach

Canada

We began in Alberta over 100 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

5,718 MW
Gross installed capacity

60 Facilities
Currently operating

Australia

TransAlta Energy Australia is building on our 20-year history in the country with significant new investments made over the past several years.

1996
First facility commissioned

450 MW
Gross installed capacity

6 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

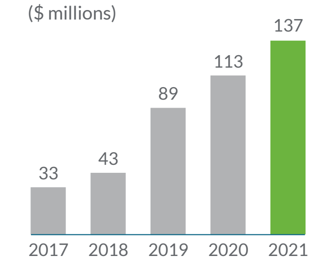
Energy Marketing: Enhancing Value

Through years of expansion and investment, we've built a leading Energy Marketing business that continues to deliver value across the fleet, supports our growth aspirations and provides a strong cash contribution to TransAlta. Energy Marketing continues to be a strong contributor to the business with improved performance year-over-year.

Fulfilling Key Roles

Managing Commodity Risk for Owned Assets ✓	Providing Market Insights for Growth ✓	Generating Strong Segment Free Cash Flow ✓

Energy Marketing EBITDA Contribution
($ millions)



What We Achieved

TransAlta had an outstanding year. We have demonstrated our leadership as a clean electricity generator with a dedicated focus on ESG. Our financial results for 2021 were fantastic and we are on solid financial footing to deliver on our growth strategy.

Awards and 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.

Bloomberg Gender-Equality Index

A market capitalization-weighted index that aims to track the performance of public companies committed to transparency in gender-data reporting.

CDP Industry Leader Score of B

This is above the North American regional average of C and represents the highest score achieved by companies in the thermal power generation sector.

Globe and Mail Board Games Rank of 6 (a score of 97 out of 100)

Board Games assesses the work of Canada's largest boards against a rigorous set of governance criteria (well beyond the minimum set by regulators).

Globe and Mail Women Lead Here

The Globe and Mail Women Lead Here list intends to set a benchmark for gender diversity in corporate Canada.

Governance Gavel Award: Best Corporate Governance Disclosure

Canadian Coalition for Good Governance awards recognize excellence in shareholder communications by issuers through their annual proxy circulars.

Energy Intelligence 2020 Green Utilities Report

The annual Green Utilities Report ranks 100 companies among the largest power generators from around the world, accounting for almost half of global capacity.

Canadian Council for Aboriginal Business

Bronze-level Progressive Aboriginal Relations recognition of our Indigenous partnerships and relationships.

Diversio

First publicly traded energy company to be certified by Diversio for its Equity, Diversity and Inclusion program.

United Way

United Way "Thanks a Million Award" recipient since 2001.

At a Glance: Exceptional Performance

$9.4 Billion
Enterprise Value[1]
Strong balance sheet and capital discipline

110 Years
Generation Experience
The foundation of our focused strategy

$3.6 Billion
Market Capitalization[1]
Listed on the TSX and the NYSE

$1.26 Billion
2021 Adjusted EBITDA[2]
A $336 million increase compared to 2020

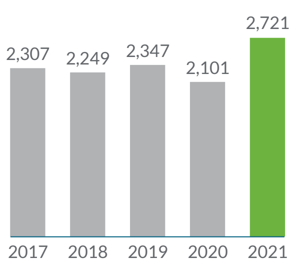
7,400 MW
Diversified Portfolio
76 generating facilities in three countries

29 Million Tonnes
GHG Reductions Since 2005
9 to 10 per cent of Canada's Paris Agreement goal

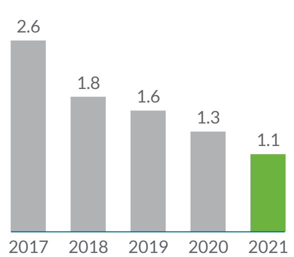
2,800 MW
Renewables Installed Capacity
Our consolidated ownership in 2021

$2.72 Billion
2021 Revenues
A $620 million increase compared to 2020

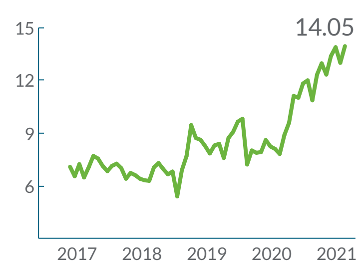
Revenues
($ millions)



Senior Corporate Debt
($ billions)



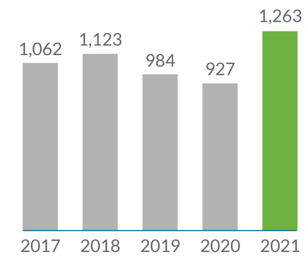
TSX Share Performance
($ per share)



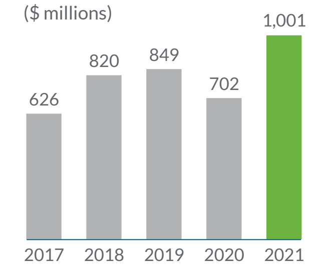
(1) At market close February 23, 2022.
(2) Non-IFRS measure. See pages M44 to M46 for details.

▶ *See pages **M12 to M14** for details on our Highlights.*

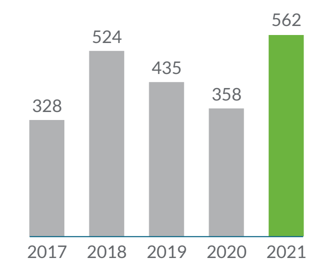
Adjusted EBITDA[1]
($ millions)



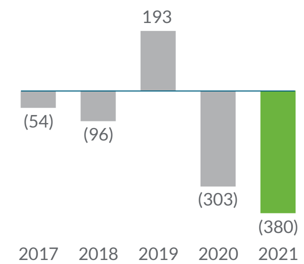
Cash Flow from Operating Activities
($ millions)



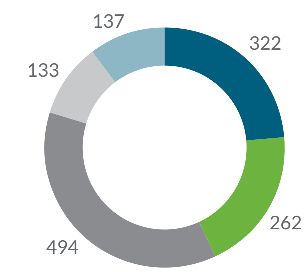
Free Cash Flow[1]
($ millions)



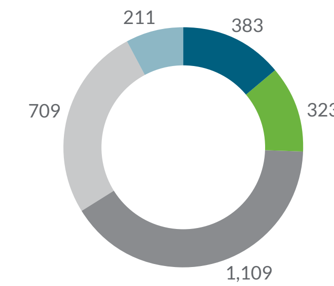
Earnings (Loss) Before Income Taxes ($ millions)



2021 Adjusted EBITDA[1,2]
($ millions)



2021 Revenues[2]
($ millions)



Hydro | Wind and Solar | Gas | Energy Transition | Energy Marketing

(1) Non-IFRS measure. See pages M44 to M46 for details.
(2) Excludes the results from the Corporate segment and our equity investments.

$3.0 Million
Community Investment in 2021
Youth and education, environmental leadership and community health and wellness

1,280
Employees
Our greatest asset and central to our value creation

38%
Women in Senior Management
This percentage is higher than our peers in Canada

42%
Women on the Board of Directors
Targeting 50 per cent female representation by 2030

▶ *See page **M67 to M112** for details on our ESG management and performance.*

What's Next

We believe the 2020s will be a decade of massive clean energy expansion 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.

Strategic Priorities: 2021 to 2025

Our strategic focus is to invest in clean energy solutions that meet the needs of our industrial customers and communities. We invest in a disciplined manner in projects that help our customers and communities meet their ESG objectives and that deliver returns to our shareholders.

1

Accelerate Growth in Customer-Centred Renewables and Storage

We are growing our renewable capacity and plan to invest $3 billion to deliver 2 GW of incremental renewable capacity by the end of 2025.

2

Take a Targeted Approach to Diversification

We are focused on growing our asset base in our core geographies of Canada, Australia and the United States to realize increased diversification and value creation.

3

Maintain Our Financial Strength and Capital Allocation Discipline

Our strong cash flow results provide a large pool of funds to be allocated to our funding priorities including growth, dividends and share buybacks.

4

Define the Next Generation of Power Solutions and Technologies

We intend to meet the needs of our customers and communities through the implementation of innovative power solutions and technologies in the latter half of this decade and beyond.

5

Lead in ESG Policy Development

We actively participate in policy development to ensure the zero-emissions electricity we provide contributes to emissions reduction, grid reliability and competitive energy prices.

6

Successfully Navigate through the COVID-19 Pandemic

We will continue to maintain an effective response to COVID-19 and plan a safe return to our offices.

Sustainability Pillars: Our Commitment

Our key strategic sustainability, or ESG, pillars build on our corporate strategy and weave through our business. Some of these focus areas are already part of our corporate culture and our track record illustrates our commitment to sustainability. In other areas where we have set new goals in recent years, we believe the focus will only strengthen our corporate strategy and support value creation into the future. Our sustainability pillars include:

1. **Clean, Reliable and Sustainable Electricity Production**
2. **Safe, Healthy, Diverse and Engaged Workplace**
3. **Positive Indigenous, Stakeholder and Customer Relationships**
4. **Progressive Environmental Stewardship**
5. **Technology and Innovation**

▶ *See page **M67 to M112** for details on our ESG management and performance.*

Sustainability Targets: Achieving Results

Our 2022 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. Goals and targets are established to improve our ESG performance and to manage current and emerging material sustainability issues.

Environment		Governance	
Reclaim land utilized for mining	✓	Strengthen gender equality	✓
Responsible water management	✓	Demonstrate leadership on ESG reporting within financial disclosures	✓
Reduce GHG emissions	✓		
Social		**Environment & Social**	
Reduce safety incidents	✓	Coal transition	✓
Support prosperous Indigenous communities	✓	Clean energy solutions for customers	✓

▶ *See pages **M71 and M72** for details on our 2021 Sustainability Performance.*

The United Nations SDGs: Our Benchmark

We establish our goals and targets utilizing the United Nations Sustainable Development Goals and the Future-Fit Business Benchmark. TransAlta is committed to decarbonizing our energy generation and to accelerating clean energy growth. We believe we can make a greater positive impact on UN SDG 7 "Affordable and Clean Energy" and SDG 13 "Climate Action", while supporting several other SDGs.

SUSTAINABLE DEVELOPMENT GOALS

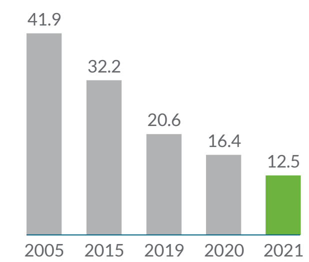
▶ *See pages **M69 and M70** for details on our 2022+ Sustainability Targets and SDG Alignment.*

Climate Change Management: Leading the Way

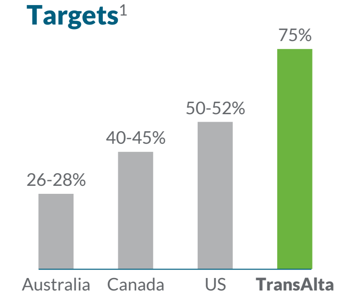
TransAlta recognizes the challenge climate change presents to society and our business, today and into the future. We have been at the forefront of open and transparent dialogue regarding climate change since the early 1990s when we supported the development of Canada's Climate Change Voluntary Challenge and Registry Program.

Since 2005, we have made tremendous progress in reducing our emissions. We have delivered over 29 million tonnes of annual greenhouse gas reductions, representing approximately 9 to 10 per cent of Canada's Paris Agreement goal of reducing between 40 to 45 per cent from 2005 levels by 2030.

TransAlta GHG Emissions
(million tonnes CO_2)



Emissions Reductions Targets[1]



From 2000 to 2021, we grew our nameplate renewables capacity from approximately 900 MW to over 2,800 MW.

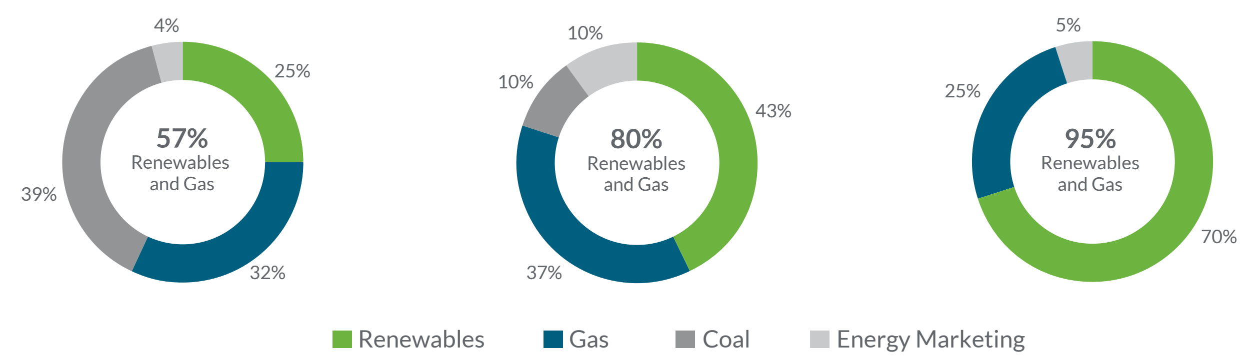
▶ *See pages **M75 to M87** for details on our Climate Change Management.*

(1) National targets are by 2030 from 2005 levels, TransAlta target is by 2026 from 2015 levels.

Clean Energy Transition: Delivering

TransAlta is currently in a multi-year transition to convert or retire all of our thermal coal units completely by the end of 2025. In 2021, we completed the transition in Canada and our coal boiler facilities and are now running solely on gas. Our remaining coal-fired facility in the United States is committed to be retired on December 31, 2025 under the *TransAlta Energy Transition Bill.*

2015 Segment EBITDA **2021 Segment EBITDA** **2025 Segment EBITDA**[2]



(2) Post-Centralia retirement.

Accelerated Clean Electricity Growth: The Plan

In September, TransAlta announced new targets and goals in the *Clean Electricity Growth Plan*. Our enhanced focus on renewable generation and storage solutions for customers is largely driven by the need to decarbonize our company and our customers' businesses and the increase of demand for renewable generation sources in our operating jurisdictions and beyond.

2017

- Announced our strategy to accelerate transition to gas and renewables generation
- Signed letter of intent to construct natural gas pipeline to service Alberta Thermal and facilitate the energy transition
- Announced gas supply conversions and accelerated conversion to gas schedule in Alberta

2021

- Deliver 2 GW of incremental renewable capacity
- Target capital investment of $3 billion
- Accelerate growth into renewables
- Expand our development pipeline to 5 GW
- Expand our platform in core geographies
- Pursue new technologies such as storage, hydrogen and carbon capture for deployment post-2026

Beyond 2030: Game-Changing Technologies

As we look beyond 2030 and our goal of carbon neutrality, we are exploring a variety of emerging technologies to meet our emissions-reduction aspirations. We intend to be a thought leader in the renewables space, bringing customized solutions that serve our company, our customers, and the communities we serve.

▶ *See pages **M9 to M11** for details on our Accelerated Clean Electricity Growth Plan.*

2026

- 70% of EBITDA from renewables and storage
- 75% GHG reduction from 2015 levels
- Coal generation discontinued across fleet

75% GHG Reduction

2030

- Enable a two-fold increase in renewables by 2030
- 5 GW accelerated growth pipeline
- New programs for growth in renewables and storage

2050

Carbon Neutrality

Management's Discussion and Analysis

Table of Contents

This Management's Discussion and Analysis ("MD&A") should be read in conjunction with our 2021 audited annual consolidated financial statements (the "consolidated financial statements") and our 2021 annual information form ("AIF"), each for the fiscal year ended Dec. 31, 2021. 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, 2021. All dollar amounts in the tables are in millions of Canadian dollars unless otherwise noted and except amounts per share, which are in whole dollars to the nearest two decimals. All other dollar amounts in this MD&A are in Canadian dollars, unless otherwise noted. This MD&A is dated February 23, 2022. Additional information respecting TransAlta Corporation ("TransAlta", "we", "our", "us" or the "Company"), including our AIF, is available on SEDAR at ***www.sedar.com****, 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 US securities laws, including the US *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 that 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: our Clean Electricity Growth Plan and ability to achieve the target of 2 gigawatts ("GW") of incremental renewables capacity with an investment of $3 billion by 2025; the Company's future growth pipeline, including the timing of commercial operations and the costs of the advanced and early-stage projects; expansion of the Company's development pipeline to 5 GW; the White Rock East and White Rock West Wind Power Projects ("White Rock Wind Projects"), including the total construction costs, ability to secure tax equity financing, the timing of commercial operation and expected average earnings before interest, taxes, depreciation and amortization ("EBITDA"); the proportion of EBITDA to be generated from renewable sources by the end of 2025; the suspension of the Sundance 5 repowering project; expected average annual EBITDA of the North Carolina Solar (as defined below) portfolio; the incident at the Kent Hills 1 and 2 wind facilities and the extent of any remediation, the timing and cost of such remediation, the ability to secure waivers in respect of the Kent Hills bonds for any potential event of default, and the impact such incident could have on the Company's revenues and contracts; the Northern Goldfields Solar Project, including the total construction capital and expected average annual EBITDA; the Garden Plain wind project, including construction capital and expected average annual EBITDA; expected increases to our cost per tonne of coal at Centralia; the expected impact and quantum of carbon compliance costs; the ability to realize future growth opportunities with BHP (as defined below); regulatory developments and their expected impact on the Company, including the Canadian federal climate plan and the implementation of the major aspects thereof (including increased carbon pricing and increased funding for clean technology); the ability of the Company to realize benefits from Canadian, US and Australian regulatory developments, including receiving funding for clean electricity projects; the potential increase in value of emission reduction credits; the 2022 financial outlook, including adjusted EBITDA, free cash flow ("FCF") and annualized dividend in 2022; increased gross margin contribution from Energy Marketing; hedged production and price for the full year 2022; hedged gas volume and gas price for 2022; sustaining and productivity capital in 2022, including routine capital, planned major maintenance and mine capital; significant planned major outages for 2022 and lost production due to planned major maintenance for 2022; expected power prices in Alberta, Ontario and the Pacific Northwest; the cyclicality of the business, including as it relates to maintenance costs, production and loads; expectations regarding refinancing the debt maturing in 2022; the liquidated damages potentially payable in respect of the Sarnia cogeneration facility outages in the second quarter of 2021; and the Company continuing to maintain a strong financial position and significant liquidity.

The forward-looking statements contained in this MD&A are based on many assumptions including, but not limited to, the following: the impacts arising from COVID-19 not becoming significantly more onerous on the Company; no significant changes to applicable laws and regulations beyond those that have already been announced; no significant changes to the fuel and purchased power costs; no material adverse impacts to the long-term investment and credit markets; Alberta spot prices of $80/MWh to $90/MWh in 2022; Mid-Columbia spot prices of US$45/MWh to US$55/MWh in 2022; sustaining capital of $150 million to $170 million; the Company's proportionate ownership of TransAlta Renewables Inc. ("TransAlta Renewables") not changing materially; no decline in the dividends to be received from TransAlta Renewables; and the growth of TransAlta Renewables. 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: the impact of COVID-19, including more restrictive directives of government and public health authorities; increased force majeure claims; reduced labour availability and ability to continue to staff our operations and facilities; disruptions to our supply chains, including our ability to secure necessary equipment; our ability to obtain regulatory approvals on the expected timelines or at all in respect of our growth projects; restricted access to capital and increased borrowing costs; changes in short-term and/or long-term electricity supply and demand; fluctuations in market prices, including lower merchant pricing in Alberta, Ontario and Mid-Columbia; reductions in production; increased costs; a higher rate of losses on our accounts receivables due to credit defaults; impairments and/or write-downs of assets; adverse impacts on our information technology systems and our internal control systems, including increased 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; changes in demand for electricity and capacity and our ability to contract our generation for prices that will provide expected returns and 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; operational risks involving our facilities, including unplanned outages; disruptions in the transmission and distribution of electricity; the effects of weather, including man-made or natural disasters and other climate-change related risks; unexpected increases in cost structure; reductions to our generating units' relative efficiency or capacity factors; disruptions in the source of fuels, including natural gas and coal, as well as the extent of water, solar or wind resources required to operate our facilities; general economic risks, including deterioration of equity markets, increasing interest rates or rising inflation; failure to meet financial expectations; general domestic and international economic and political developments, including armed hostilities, the threat of terrorism, including cyberattacks, diplomatic developments or other similar events that could adversely affect our business; equipment failure and our ability to carry out or have completed the repairs in a cost-effective manner or timely manner or at all, including if the remediation at the Kent Hills 1 and 2 wind facilities is more costly or takes longer than expected; industry risk and competition; fluctuations in the value of foreign currencies; structural subordination of securities; counterparty credit risk; changes to our relationship with, or ownership of, TransAlta Renewables; changes in the payment or receipt of future dividends, including from TransAlta Renewables; risks associated with development projects and acquisitions, including capital costs, permitting, labour and engineering risks, and delays in the construction or commissioning of projects; inadequacy or unavailability of insurance coverage; our provision for income taxes; legal, regulatory and contractual disputes and proceedings involving the Company; reliance on key personnel; and labour relations matters. 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, 2021.

Readers are urged to consider these factors carefully in 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

Portfolio of Assets

TransAlta is a Canadian corporation and one of Canada's largest publicly traded power generators with over 110 years of operating experience. We own, operate and manage a geographically diversified portfolio of assets utilizing a broad range of fuels that includes water, wind, solar, natural gas and thermal coal.

The following table provides our consolidated ownership of our facilities across the regions in which we operate as at Dec. 31, 2021:

As at Dec. 31, 2021		Hydro	Wind and Solar[4]	Gas[4][5]	Energy Transition[6]	Total
Alberta	Gross installed capacity (MW)[1]	834	636	1,960	801	4,231
	Number of facilities	17	13	7	2	39
	Weighted average contract life[2]	—	7	1	—	2
Canada, Excl. Alberta	Gross installed capacity (MW)[1]	91	751	645	—	1,487
	Number of facilities	9	9	3	—	21
	Weighted average contract life[3]	7	10	6	—	8
US	Gross installed capacity (MW)[1]	—	519	29	671	1,219
	Number of facilities	—	7	1	2	10
	Weighted average contract life[3]	—	12	4	4	8
Australia	Gross installed capacity (MW)[1]	—	—	450	—	450
	Number of facilities	—	—	6	—	6
	Weighted average contract life[3]	—	—	17	—	17
Total	**Gross installed capacity (MW)[1]**	925	1,906	3,084	1,472	7,387
	Number of facilities	26	29	17	4	76
	Weighted average contract life[3]	1	9	5	2	5

(1) Gross installed capacity for consolidated reporting represents 100 per cent output of a facility. Capacity figures for Wind and Solar includes 100 per cent of the Kent Hills wind facilities; Gas includes 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.
(2) The weighted average contract life for the assets in Alberta are nil as it is operating primarily on a merchant basis in the Alberta market. Refer to the Alberta Electricity Portfolio section for more information.
(3) For power generated under long-term power purchase agreements ("PPA"), power hedge contracts and short- and long-term industrial contracts, the PPAs have a weighted average remaining contract life (based on gross long-term average gross installed capacity).
(4) The weighted average remaining contract life is related to the contract period for the McBride Lake (38 MW), the Windrise facility (206 MW), Poplar Creek facility (115 MW) and the Fort Saskatchewan facility (71 MW), with remaining wind and gas facilities operated on a merchant basis.in the Alberta market.
(5) Gas segment includes the segments previously known as Australian Gas and North American Gas and the coal generation assets converted to gas from the segment previously known as Alberta Thermal.
(6) Energy Transition segment includes the segment previously known as Centralia and the coal generation assets not converted to gas (including Sundance 4) and mining assets from the segment previously known as Alberta Thermal.

Our Clean Energy Investment Plan, announced in 2019, included converting our existing Alberta coal assets to natural gas and advancing our leadership position in renewable electricity. To date, we have retired 4,064 MW of coal-fired generation capacity since 2018 while converting 1,659 MW to natural gas, significantly reducing our carbon footprint. During 2021, we increased our renewable fleet by 334 MW through acquisitions and construction of renewable wind and solar facilities and on Sept 28, 2021, we announced a Clean Electricity Growth Plan that includes strategic growth targets. Please refer to the Accelerated Clean Electricity Growth Plan section of this MD&A for further information.

Approximately 57 per cent of our gross installed capacity is located in Alberta. Our portfolio of merchant assets in Alberta is a combination of hydro facilities, wind facilities, a battery storage facility and converted natural-gas-fired thermal facilities. This balance of fuel types provides us with portfolio generation diversification. It also provides us with capacity that can be monetized as ancillary services or dispatched into the energy market during times of supply tightness. We also enter into financial contracts to reduce our exposure to variable power prices on our merchant generation. Please refer to the Alberta Electricity Portfolio section of this MD&A for further information.

Clean Energy Transition

The Company has completed the conversion to gas at its Alberta facilities that were formerly fuelled by coal; these facilities are now running solely on gas. The Company retired the Highvale coal mine effective Dec. 31, 2021, and is no longer mining coal. Our Centralia coal-fired facility in Washington State is committed to be retired under the *TransAlta Energy Transition Bill* by 2025. Centralia Unit 1 retired on Dec. 31, 2020, and the remaining unit, Centralia Unit 2, is scheduled to retire on Dec. 31, 2025.

The following table shows the Company's completed conversions to gas:

Project	MW	Cumulative Conversion Project Spend[1]	Project Completion Date
Keephills Unit 3	463	$31	Q4 2021
Keephills Unit 2	395	$34	Q2 2021
Sundance Unit 6	401	$39	Q1 2021
Sheerness Unit 1[2]	200	$7	Q1 2021
Sheerness Unit 2[2]	200	$14	Q1 2020

(1) Conversion project spend only includes costs associated with the conversion to gas-burning technology. Any additional planned major maintenance has been included as part of sustaining capital spend.
(2) These facilities are jointly owned by TransAlta Cogeneration L.P. ("TA Cogen") and Heartland Generation Ltd. This represents the portion of the 400 MW facility consolidated by the Company.

During the 2021 Investor Day, the Company announced its decision to retire Keephills Unit 1 and Sundance Unit 4 effective Dec. 31, 2021, and April 1, 2022, respectively. The retirement decisions were largely driven by TransAlta's assessment of future market conditions, the age and condition of the units and the Company's strategic focus on customer-centred renewable energy solutions. As a result of the decision to retire these units, the Company recorded impairment charges of $94 million and $56 million, respectively, on these units based on the estimated salvage value.

Following an in-depth evaluation and assessment of the Sundance Unit 5 repowering project, the Company suspended the project. The decision was made due to escalating costs, changing supply and demand dynamics and forecasted power prices in the Alberta market, as well as risks associated with carbon pricing and the evolving regulatory environment. With the suspension of the project, the Company will redeploy the capital previously allocated to the Sundance Unit 5 repowering project to renewable growth projects. The Company recorded an impairment charge of $191 million in 2021 in relation to the project. The total remaining estimated recoverable amount and salvage value for the Sundance Unit 5 repowering project was $33 million. Of this amount, $25 million was related to assets held for sale. Included in the impairment charge was $141 million for assets under construction and $50 million for the balance of the plant steam equipment. An additional $20 million was expensed for amounts due under contracts as a result of the suspension of the project.

With the suspension of the Sundance Unit 5, we have also impaired a previously recognized deferred asset, as it is no longer likely that we will incur sufficient capital or operating expenditures to utilize the remaining credit. The Company impaired the remaining balance of the credit of $10 million (US$8 million) in 2021.

The Highvale mine is no longer considered to be providing significant economic benefit to the Alberta Merchant cash-generating unit ("CGU") and it has been removed from the CGU, which resulted in an impairment recognized in 2021 of $195 million. An onerous contract provision of $14 million relating to future Highvale mine royalty payments (2022 and 2023), has also been recognized as an expense in 2021.

With the successful completion of the Keephills Unit 3 conversion on Dec. 29, 2021, and the planned closure of the Highvale coal mine effective Dec. 31, 2021, TransAlta's thermal facilities in Alberta have been fully transitioned to 100 per cent natural gas operation. We have reduced our CO_2 emissions by 61 per cent from 2015 levels.

Reporting Segment Changes

With the completion of the Clean Energy Transition plan and the announcement of our strategic focus on customer-centred renewable generation, the Company has realigned its current operating segments to better reflect its current strategic focus and to align with the Company's Clean Electricity Growth Plan. The segment reporting changes reflect a corresponding change in how the Chief Executive Officer assesses the performance of the Company.

The primary changes are the elimination of the Alberta Thermal and the Centralia segments and the reorganization of the North American Gas and Australia Gas segments into a new "Gas" segment. The Alberta Thermal facilities that have been converted to gas are included in the Gas segment. The remaining assets previously included in Alberta Thermal, including the mining assets and those facilities not converted to gas and the remaining Centralia unit, are included in a new "Energy Transition" segment. No changes have been made to the Hydro, Wind and Solar, Energy Marketing or the Corporate and Other segments. Please refer to the Segmented Financial Performance and Operating Results section of this MD&A for further information.

Performance by Segment with Supplemental Geographical Information

The following table provides the performance of our facilities across the regions we operate in as at Dec. 31, 2021, and Dec. 31, 2020:

Year ended Dec. 31, 2021	**Hydro**	**Wind and Solar**	**Gas(1)**	**Energy Transition(2)**	**Energy Marketing**	**Corporate and Other**	**Total**
Alberta	**308**	**63**	**269**	**59**	**—**	**(85)**	**614**
Canada, excl. Alberta	**14**	**120**	**75**	**—**	**137**	**—**	**346**
US	**—**	**79**	**10**	**74**	**—**	**—**	**163**
Australia	**—**	**—**	**140**	**—**	**—**	**—**	**140**
Total adjusted EBITDA(3)	**322**	**262**	**494**	**133**	**137**	**(85)**	**1,263**
Loss before income taxes							**(380)**

Year ended Dec. 31, 2020	Hydro	Wind and Solar	Gas(1)	Energy Transition(2)	Energy Marketing	Corporate and Other	Total
Alberta	88	18	151	36	—	(81)	212
Canada, excl. Alberta	17	153	88	—	113	—	371
US	—	77	4	139	—	—	220
Australia	—	—	124	—	—	—	124
Total adjusted EBITDA(3)	105	248	367	175	113	(81)	927
Loss before income taxes							(303)

(1) Gas segment includes the segments previously known as Australian Gas and North American Gas and the coal generation assets converted to gas from the segment previously known as Alberta Thermal.
(2) Energy Transition segment includes the segment previously known as Centralia and the coal generation assets not converted to gas and mining assets from the segment previously known as Alberta Thermal.
(3) 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 trends more readily in comparison with prior periods' results. Please 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. See also the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Alberta Electricity Portfolio

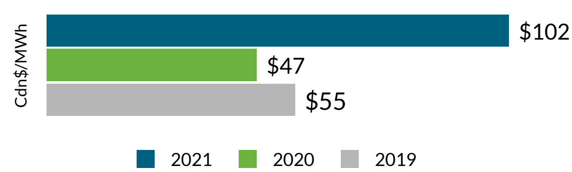
Generating capacity in Alberta is subject to market forces, rather than rate regulation. Power from commercial generation is cleared through a wholesale electricity market. Power is dispatched in accordance with an economic merit order administered by the Alberta Electric System Operator ("AESO"), based 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.

On Dec. 31, 2020, the legislated Alberta Power Purchase Arrangements ("Alberta PPA") for our Alberta hydro assets ("Alberta Hydro Assets"), Sheerness 1 and 2 Units, and the Keephills 1 and 2 Units expired. Effective Jan. 1, 2021, these facilities began operating on a fully merchant basis in the Alberta market and form a core part of our Alberta portfolio optimization activities.

The Alberta Electricity Portfolio generated gross margin of $864 million, an increase of $405 million compared to the same period in 2020. This performance was driven by strengthened power prices in the province, optimization of production during periods of favourable pricing, partially offset by higher natural gas and carbon pricing and higher transmission costs. Optimization of facilities is driven by the diversity in fuel types, which enables portfolio management and allows for maximization of operating margins. A portion of the baseload generation in the portfolio is hedged to provide cash flow certainty. The portfolio consists of hydro, wind, energy storage and natural gas units operating, primarily, on a merchant basis in the Alberta market. Prior to 2022, the Alberta Electricity Portfolio also included coal units, which are now either retired, have been converted to natural gas or will only operate on gas. Sundance Unit 4 will continue to operate within the portfolio, fuelled only by gas, until its retirement date on April 1, 2022.

Alberta's annual demand expanded approximately 3.0 per cent from 2020 to 2021 as the economy recovered from the impacts of the COVID-19 pandemic and stronger market conditions for energy commodities supported power demand in the province. The average pool price increased from $47/MWh in 2020 to $102/MWh in 2021. Pool prices were higher in each quarter compared to 2020, generally as a result of competition among generators, higher demand in the province, tighter supply conditions due to higher planned outages, and higher natural gas and carbon prices. In addition, in 2021, Alberta experienced very strong weather-driven demand in February, June, July and December.

Alberta Average Spot Electricity Prices



Year ended Dec. 31	**2021** Hydro	**2021** Wind & Solar	**2021** Gas	**2021** Energy Transition	**2021** Total	2020 Hydro	2020 Wind & Solar	2020 Gas	2020 Energy Transition	2020 Total	2019 Hydro	2019 Wind & Solar	2019 Gas	2019 Energy Transition	2019 Total
Total Production (GWh)[1]	**1,586**	**1,319**	**7,281**	**2,591**	**12,777**	1,779	1,320	7,732	2,865	13,696	1,715	1,058	8,691	4,698	16,162
Revenues	**358**	**97**	**680**	**257**	**1,392**	126	57	482	207	872	132	59	519	334	1,044
Fuel and purchased power	**13**	**9**	**258**	**92**	**372**	6	15	151	73	245	4	6	151	84	245
Carbon compliance	**—**	**—**	**96**	**60**	**156**	—	—	120	48	168	—	—	138	77	215
Gross margin	**345**	**88**	**326**	**105**	**864**	120	42	211	86	459	128	53	230	173	584

(1) Units in the Gas and Energy Transition segment in the current and prior years may have operated on coal.

The following table provides information for the Company's Alberta Electricity Portfolio:

Year ended Dec. 31	**2021**	2020	2019
Spot power price average per MWh	**$102**	$47	$55
Natural gas price (AECO) per GJ	**$3.39**	$2.11	$1.68
Carbon cost per tonne	**$40**	$30	$20
Realized power price per MWh(1)	**$109**	$64	$65
Hydro energy realized power price per MWh	**$122**	$51	$61
Hydro ancillary realized price per MWh	**$55**	$23	$30
Wind energy realized power price per MWh	**$63**	$33	$38
Gas and Energy Transition realized power price per MWh	**$102**	$71	$64
Hedged volume (MW)(2)	**6,992**	5,395	5,187
Hedge position (percentage)(3)	**75**	100	87
Hedged power price average per MWh(2)	**$72**	$54	$55
Fuel and purchased power per MWh(4)	**$38**	$23	$18
Carbon compliance cost per MWh(4)	**$16**	$16	$16

(1) Realized power price for the Alberta Electricity Portfolio is the average price realized as a result of the Company's commercial contracted sales and portfolio optimization activities divided by total GWh produced.
(2) In 2020 and 2019, much of the portfolio in Alberta was still under PPAs and the PPA volumes are not included in the total hedged volumes listed above.
(3) Represents the percentage of production sold forward at the end of the reporting period for the Gas assets only. The hedge program is focused primarily on generation from the merchant Gas and Energy Transition assets.
(4) Fuel and purchased power per MWh and carbon compliance cost per MWh are calculated over production from carbon-emitting generation segments in Gas and Energy Transition.

For the year ended Dec. 31, 2021, the realized power price per MWh of production increased by $45 per MWh, compared with the same period in 2020, primarily due to the optimization of production during periods of favourable pricing. The realized prices include gains and losses from hedging positions that are entered into in order to mitigate the impact of unfavourable market pricing.

For the year ended Dec. 31, 2021, the fuel and purchased power cost per MWh of production increased by $15 per MWh compared to the same period in 2020. Cost per MWh increased due to higher natural gas pricing, higher coal mine depreciation and coal inventory write-downs at the Highvale mine and higher transmission costs.

For the year ended Dec. 31, 2021, carbon compliance costs per MWh of production were consistent with the same period in 2020. Carbon compliance costs have increased in 2021 primarily due to an increase in carbon price from $30 per tonne to $40 per tonne; however, this was substantially offset by changes in fuel ratios as we increased our natural gas combustion compared to coal. The shift in fuel ratio effectively lowered our greenhouse gas ("GHG") compliance costs as natural gas combustion produces fewer GHG emissions than coal combustion.

Accelerated Clean Electricity Growth Plan

On Sept. 28, 2021, TransAlta announced its strategic growth targets and Accelerated Clean Electricity Growth Plan. Our goal is to be a leading customer-centred electricity company, committed to a sustainable future, focused on increasing shareholder value by growing our portfolio of high quality generation facilities with stable and predictable cash flows. Our strategy includes meeting our customers' needs for clean, low-cost, reliable electricity and providing operational excellence and continuous improvement in everything we do.

The Company's enhanced focus on renewable generation and storage solutions for customers is driven largely by global decarbonization policies and the increase in demand and growth projections in the renewable sector, namely for companies to achieve their environment, social and governance ("ESG") ambitions. For additional information on regulatory developments, see the ESG section of this MD&A.

We are primarily evaluating greenfield opportunities in Alberta, Western Australia and the US along with acquisitions in markets in which we have existing operations. We maintain highly qualified and experienced development teams to identify and develop these opportunities.

Our Accelerated Clean Electricity Growth Plan has established the following strategic priorities and targets to guide our path from 2021 to 2025. These include:

- Deliver 2 GW of incremental renewable capacity with a targeted capital investment of $3 billion by the end of 2025. These new assets, once fully operational are targeted to deliver incremental average annual EBITDA[1] of $250 million;
- Accelerate growth into customer-centred renewables and storage through the deployment of our 3 GW development pipeline;
- Expand the Company's development pipeline to 5 GW by 2025 to enable a two-fold increase in its renewables fleet between 2025 and 2030;
- Realize targeted diversification and value creation by focusing on expanding our platform in each of our core geographies (Canada, United States and Australia);
- Lead in ESG policy development to enable the successful evolution of the markets in which we operate and compete; and
- Define the next generation of power solutions and technologies and potential for parallel investments in new complementary sectors by the end of 2025.

We expect the Company's EBITDA generated from renewable sources, including hydro, wind, and solar technologies, to increase from 35 per cent to 70 per cent by the end of 2025.

The Clean Electricity Growth Plan will largely be funded from current cash balances, cash generated from operations, and asset-level financing.

Growth

In 2021, the Company announced 600 MW of new build projects and asset acquisitions and has 240 MW in advanced-stage development. In addition, the current growth pipeline has a potential capacity ranging from 2,085 MW to 2,685 MW from projects in the early stages of development.

Announced Acquisition

North Carolina Solar

On Nov. 5, 2021, the Company closed the previously announced acquisition of a 122 MW portfolio of operating solar sites located in North Carolina (collectively, "North Carolina Solar"). The North Carolina Solar facility consists of 20 solar photovoltaic sites across North Carolina. The sites were commissioned between November 2019 and May 2021 and are all operational. The facility is secured by long-term PPAs with Duke Energy, which have an average remaining term of 12 years. Under the PPAs, Duke Energy receives the renewable electricity, capacity and environmental attributes from each site. The North Carolina Solar facility is expected to generate an average annual EBITDA[1] of approximately US$9 million and average annual cash available for distribution of approximately US$7 million.

[1] *Average annual EBITDA is not defined and has no standardized meaning under IFRS, and is forward-looking. Please refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further discussion.*

Projects under Construction

The following projects have been approved by the Board of Directors ("the Board"), have executed PPAs and are currently under construction. The projects under construction will be financed through existing liquidity in the near term. We will continue to explore project financing or tax equity as a long-term financing solution on an asset-by-asset basis.

Project	Type	Region	MW	Total project: Estimated spend	Total project: Spent to date	Target completion date[1]	PPA Term	Average annual EBITDA[2]	Status
Projects Under Construction or Approved for Construction									
Canada									
Garden Plain[3]	Wind	AB	130	$190 — $200	$37	H2 2022	18	$14 - $18	• Secured all required permits and approvals • Construction activities commenced in Q4 2021 • On track to be completed on schedule
United States									
White Rock Wind	Wind	OK	300	US$460 — US$470	US$30	H2 2023		US$42 - US$46	• Long-term PPA executed • All major equipment supply and EPC agreements executed • Detailed design and final permitting on track
Australia									
Northern Goldfields Solar	Hybrid Solar	WA	48	AU$69 — AU$73	AU$15	H2 2022	16	AU$9 - AU$10	• Final Notice to Proceed issued on Sept. 28, 2021 • On track to be completed on schedule

(1) H2 is defined as the second half of the year
(2) This item is not defined and has no standardized meaning under IFRS and is forward-looking. Please refer to the Additional IFRS measures and Non-IFRS Measures section of this MD&A for further discussion.
(3) The Garden Plain PPA with Pembina Pipeline Corporation ("Pembina") is for 100 MW of the total 130 MW capacity of the facility.

Advanced-Stage Development

These projects have detailed engineering, advanced position in the interconnection queue and are progressing offtake opportunities. The following table shows the pipeline of future growth projects currently under advanced-stage development:

Project	Type	Region	Gross Installed Capacity (MW)	Estimated Spend	Average Annual EBITDA[1]
Advanced-Stage Development					
Horizon Hill	Wind	Oklahoma	200	US$290 - US$310	US$25 - US$35
Mount Keith 132kV Expansion	Transmission	Western Australia	n/a	AU$50 - AU$53	AU$6 - AU$7
Mount Keith Capacity Expansion	Gas	Western Australia	40	AU$80 - AU$100	AU$9 - AU$12

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

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		Gross Installed Capacity (MW)
Early-Stage Development				
Canada				
Riplinger Wind	Wind	Alberta		300
Willow Creek 1	Wind	Alberta		70
Willow Creek 2	Wind	Alberta		70
Tempest	Wind	Alberta		100
WaterCharger	Battery Storage	Alberta		180
Sunhills Solar	Solar	Alberta		85
Alberta Solar Opportunities	Solar	Alberta		35
Canadian Wind Opportunities	Wind	Various		200
Brazeau Pumped Hydro	Hydro	Alberta		300 - 900
			Total	**1,340 - 1,940**
US				
Prairie Violet	Wind	Illinois		130
Old Town	Wind	Illinois		185
Big Timber	Wind	Pennsylvania		50
Other US Wind Prospects	Wind	Various		240
			Total	**605**
Australia				
Goldfields Expansions	Gas, Solar and Wind	Western Australia		90
South Hedland Solar	Solar	Western Australia		50
			Total	**140**
Canada, US and Australia			**Total**	**2,085 - 2,685**

Highlights

Consolidated Financial Highlights

Year ended Dec. 31	2021	2020	2019
Adjusted availability (%)	**86.6**	90.7	90.0
Production (GWh)	**22,105**	24,980	29,071
Revenues	**2,721**	2,101	2,347
Fuel and purchased power(1)	**1,054**	805	881
Carbon compliance(1)	**178**	163	205
Operations, maintenance and administration	**511**	472	475
Adjusted EBITDA(2,3,7)	**1,263**	927	984
Earnings (loss) before income tax	**(380)**	(303)	193
Net earnings (loss) attributable to common shareholders	**(576)**	(336)	52
Cash flow from operating activities	**1,001**	702	849
Funds from operations(2,3)	**971**	685	757
Free cash flow(2,3)	**562**	358	435
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(2.13)**	(1.22)	0.18
Dividends declared per common share(4)	**0.19**	0.22	0.12
Dividends declared per preferred share(5)	**1.02**	1.27	0.78
Funds from operations per share(2,3,8)	**3.58**	2.49	2.67
Free cash flow per share(2,3,8)	**2.07**	1.30	1.54

As at Dec. 31	2021	2020	2019
Total assets	**9,226**	9,747	9,508
Total consolidated net debt(3,6)	**2,636**	2,974	3,110
Total long-term liabilities	**4,702**	5,376	4,329
Total liabilities	**6,633**	6,311	5,446

(1) Carbon compliance costs have been reclassified from fuel and purchase power costs and disclosed separately. Prior periods have been adjusted for comparative purposes and did not impact previously reported net earnings.
(2) Includes $56 million received on settlement of the dispute with the Balancing Pool in the third quarter of 2019.
(3) 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 trends more readily in comparison with prior periods' results. Please 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. See also the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.
(4) No dividends were declared in the first quarter of 2021 as the quarterly dividend related to the period covering the first quarter of 2021 was declared in December 2020.
(5) Weighted average of the Series A, B, C, E and G preferred share dividends declared. Dividends declared vary year over year due to timing of dividend declarations.
(6) Total consolidated net debt includes long-term debt, including current portion, amounts due under credit facilities, exchangeable securities, US tax equity financing and lease liabilities, net of available cash and cash equivalents, the principal portion of restricted cash on our subsidiary TransAlta OCP LP ("TransAlta OCP") and the fair value of economic hedging instruments on debt. See the table in the Financial Capital section of this MD&A for more details on the composition of total consolidated net debt.
(7) In the fourth quarter of 2021, comparable EBITDA was relabelled as adjusted EBITDA to align with industry standard terminology.
(8) Funds from operations ("FFO") per share and free cash flow per share are calculated using the weighted average number of common shares outstanding during the period. The weighted average number of common shares outstanding at Dec. 31, 2021 was 271 million shares (2020 - 275 million shares and 2019 - 283 million shares). Please refer to the Additional IFRS Measures and Non-IFRS Measures section in this MD&A for the purpose of these non-IFRS ratios.

We have seen exceptional performance from our Alberta Electricity Portfolio, driving overall strong performance for the Company. Both the Hydro and Gas segments had high availability on the merchant assets during periods of peak pricing, which resulted from abnormally warm summer and cold winter weather and periods of province-wide planned thermal outages. The Alberta merchant portfolio was positioned to capture opportunities from these strong spot market conditions through both energy and ancillary service revenues. This was further supplemented by strong performance in our Energy Marketing segment.

Adjusted availability for 2021 was 86.6 per cent compared to 90.7 per cent in 2020. The decrease was primarily due to higher planned and unplanned outages in the Energy Transition segment. The unplanned outages at Centralia Unit 2 and Sundance Unit 4 adversely impacted availability. In addition, adjusted availability was reduced by the planned outages for the Keephills Unit 2 and Keephills Unit 3 boiler conversions. The unplanned outage at the Kent Hills 1 and 2 wind facilities further contributed to reduced adjusted availability.

Production for 2021 was 22,105 gigawatt hours ("GWh") compared to 24,980 GWh in 2020. Overall, the decrease in production was primarily due to the planned retirement of Centralia Unit 1, portfolio optimization activities in Alberta, lower wind resources, the outage at the Kent Hills 1 and 2 wind facilities in the Wind and Solar segment and lower capacity loads in the Gas segment. This was partially offset by higher incremental production at our Ada facility within our Gas segment and higher incremental production from the Skookumchuck wind facility, the Windrise wind facility and the North Carolina Solar facility in the Wind and Solar segment.

Revenues for 2021 increased by $620 million compared to 2020, mainly as a result of capturing higher realized prices within the Alberta market through our optimization and operating activities and the elimination of the net payment obligations under the Alberta Hydro PPA required in the prior period. Revenues also increased due to the strong performance from the Energy Marketing segment, an increase in revenues within the Gas segment from the addition of the Ada facility and an increase within the Wind and Solar segment from the addition of the North Carolina Solar facility and the Windrise wind facility. These increases were partially offset by lower production in the Energy Transition, Hydro, Wind and Solar, and Gas segments.

Fuel and purchased power costs in 2021 increased by $249 million compared to 2020. In our Energy Transition segment, our fuel and purchased power costs increased compared to 2020 due to higher fuel transportation costs and the acquisition of higher-priced power during periods of higher merchant pricing to fulfil our contractual obligations during planned and unplanned outages at the Centralia facility. In addition, the Gas and Energy Transition segments experienced higher natural gas pricing, higher coal mine depreciation and coal inventory write-downs at the Highvale mine, all of which contributed to higher fuel costs.

Carbon compliance costs increased by $15 million compared to 2020, due to an increase in the carbon price per tonne, partially offset by reductions in GHG emissions stemming from changes in the fuel mix ratio as we operated more on natural gas and fired less with coal. Additionally, carbon compliance costs were partially offset by lower production in the Gas and Energy Transition segments. Operating with natural gas reduces carbon compliance costs as we produce fewer GHG emissions than by using coal.

Operations, maintenance and administration ("OM&A") expenses for 2021 increased by $39 million compared to 2020. A write-down of $28 million was recorded on parts and material inventory related to the Highvale mine and coal operations at our natural gas converted facilities. In addition, variability caused by the total return swap resulted in a favourable change of $7 million. During 2021, we received a Canada Emergency Wage Subsidy ("CEWS") of $8 million. Excluding the impact of the total return swap, CEWS funding and inventory write-down, OM&A expenses were higher compared to the same periods in 2020, primarily due to increased staffing costs for growth and strategic initiatives and higher incentive costs. In addition, there were additional costs associated with the legal fees and the settlement of outstanding legal issues. As previously committed, the CEWS funding continues to be used to support incremental employment within the Company.

Adjusted EBITDA increased by $336 million compared to 2020. Adjusted EBITDA increased largely due to higher gross margin, driven by higher realized prices and dispatch optimization in the Alberta market from our merchant facilities residing in the Alberta Electricity Portfolio across the Hydro, Wind and Solar, Gas, and Energy Transition segments. In addition, the Energy Marketing segment also increased adjusted EBITDA due to favourable short-term trading of both physical and financial power and natural gas products across North American markets. This increase was partially offset by the retirement of Centralia Unit 1, unplanned outages at Centralia Unit 2 in the Energy Transition segment and the extended site outage at the Kent Hills 1 and 2 wind facilities. Significant changes in segmented adjusted EBITDA are highlighted in the Segmented Financial Performance and Operating Results section within this MD&A.

Loss before income taxes for 2021 increased by $77 million compared to 2020. **Net loss attributable to common shareholders** for 2021 was $576 million compared to a loss of $336 million in 2020. The higher loss before income taxes and the higher net loss attributable to common shareholders in 2021 was largely driven by higher asset impairments related to decisions to shut down the Highvale mine, suspend the Sundance 5 repowering project and planned retirements of Sundance Unit 4 and Keephills Unit 1. These higher asset impairments were partially offset by higher adjusted EBITDA largely resulting from the strong performance of the Alberta Electricity Portfolio across all of our fuel segments, higher gains on sale of assets due to the gain on sale of equipment in the Energy Transition segment and the gain from the sale of the Pioneer Pipeline in the Gas segment and lower depreciation. The higher net loss attributable to common shareholders was also impacted by higher income tax expense in 2021 due to higher earnings in the Energy Marketing segment and from the Alberta Electricity Portfolio.

Cash flow from operating activities increased by $299 million compared with 2020, primarily due to higher revenues being realized in Alberta on the merchant assets and changes in non-cash working capital, partially offset by higher fuel and purchased power and OM&A costs as the Company transitioned off coal.

FCF, one of the Company's key financial metrics, totalled $562 million compared to $358 million in 2020. This represents an increase of $204 million, driven primarily by higher adjusted EBITDA, partially offset by an increase in sustaining capital spending related to higher planned maintenance and facility turnarounds, settlement of provisions and higher distributions paid to subsidiaries' non-controlling interests.

Sustaining Capital

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

Year ended Dec. 31	2021	2020	2019
Total sustaining capital expenditures	**199**	157	141

Total sustaining capital expenditures were $42 million higher compared to 2020, mainly due to higher planned major maintenance turnarounds related to Keephills Unit 2 and 3 and Sheerness Unit 1 and distributed planned maintenance expenditures across the entire hydro and wind fleet, with a focus on planned component replacements in the wind fleet.

Ability to Deliver Financial Results

The metrics we use to track our performance are adjusted EBITDA and FCF. The following table compares target to actual amounts for each of the three past fiscal years:

Year ended Dec. 31		2021	2020	2019
Adjusted EBITDA (1)	Target(2)	**1,200-1,300**	925-1000	875-975
	Actual	**1,263**	927	984
FCF (1)	Target(2)	**500-560**	325-375	350-380
	Actual	**562**	358	435

(1) These items are not defined and have no standardized meaning under IFRS. Please refer to the Additional IFRS Measures and 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.
(2) This represents our revised outlook, as a result of strong performance in the second and third quarters of 2021, the Company revised the following 2021 targets: Adjusted EBITDA from the previously announced target range of $960 million - $1,080 million to the target range of $1,200 million - $1,300 million and FCF target range from $340 million - $440 million to the target range of $500 million - $560 million. In addition, during the fourth quarter of 2019, we revised our FCF target from a range of $270 million to $330 million to a range of $350 million to $380 million.

Significant and Subsequent Events

White Rock Wind Projects and Fully Executed Corporate PPAs

On Dec. 22, 2021, TransAlta executed two long-term PPAs with a new customer with an AA credit rating from S&P Global Ratings for 100 per cent of the generation from its 300 MW White Rock Wind Projects to be located in Caddo County, Oklahoma. The White Rock Wind Projects will consist of a total of 51 Vestas turbines. Construction is expected to begin in late 2022 with a target commercial operation date in the second half of 2023. TransAlta will construct, operate and own the facilities. Total construction capital is estimated at approximately US$460 million to US$470 million and is expected to be financed with a combination of existing liquidity and tax equity financing. Over 90 per cent of the project costs are captured under executed fixed price turbine supply agreements and fixed price engineering, procurement and construction agreements. The project is expected to generate average annual EBITDA[2] of approximately US$42 million to US$46 million including production tax credits.

North Carolina Solar Acquisition

On Nov. 5, 2021, the Company closed the acquisition of a 122 MW portfolio of 20 solar photovoltaic sites located in North Carolina. The assets were acquired from a fund managed by Copenhagen Infrastructure Partners for approximately US$99 million (including working capital adjustments) and the assumption of existing tax equity obligations. The acquisition was funded using existing liquidity.

At the closing of the acquisition, TransAlta Renewables acquired a 100 per cent economic interest in North Carolina Solar from a wholly owned subsidiary of TransAlta through a tracking share structure for aggregate consideration of approximately US$102 million.

[2] *Average annual EBITDA is not defined and has no standardized meaning under IFRS, and is forward-looking. Please refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further discussion.*

The facilities are all operational and were commissioned between November 2019 and May 2021. The facilities are secured by PPAs with Duke Energy, which have an average remaining term of 12 years. Under the PPAs, Duke Energy receives the renewable electricity, capacity and environmental attributes from each facility. North Carolina Solar is expected to generate an average annual EBITDA[3] of approximately US$9 million.

Kent Hills Wind Facilities Outage

On Sept. 27, 2021, the Company's subsidiary, Kent Hills Wind LP, experienced a single tower failure at its 167 MW Kent Hills wind facilities in Kent Hills, New Brunswick. The failure involved a collapsed tower located within the Kent Hills 2 site. There were no injuries as a result of the collapse. No one was in the area when the incident occurred and there are no homes in the immediate vicinity. The Company's emergency response team secured the area to ensure safety. The Company recorded an impairment charge of $2 million on the collapsed tower.

The facilities consist of 50 turbines at the Kent Hills 1 and 2 wind facilities and five turbines at Kent Hills 3. Following extensive independent engineering assessments and root cause failure analysis, the Company announced on Jan. 11, 2022, that all 50 turbine foundations at the Kent Hills 1 and 2 wind facilities require a full foundation replacement. The root cause failure analysis indicates that deficiencies in the original design of the foundations had led to subsurface crack propagation within the foundations and that the foundations must be replaced. The Company is in the process of planning the rehabilitation of the wind sites and currently expects the wind facility foundations to be fully replaced by the end of 2023. Based on the recommendations of independent engineers, and in order to maintain the safety of the affected facilities and turbines, the wind turbines will cease to operate until their associated foundations are replaced. The Company has recorded $12 million of accelerated depreciation relating to the 50 foundations that will be replaced.

Foundation replacements will require expenditures of approximately $75 million to $100 million, in aggregate. The remediation plan is expected to begin to be implemented in 2022. The outage is expected to result in foregone revenue of approximately $3.4 million per month on an annualized basis so long as all 50 turbines are offline, based on average historical wind production, with revenue expected to be earned as the wind turbines are returned to service.

TransAlta and New Brunswick Power Corporation continue discussions to enable the safe return to service of the facilities.

The foundation issues at the Kent Hills 1 and 2 wind facilities are unique to the design of those sites and there is no indication of any foundation issue at the Kent Hills 3 facility or any other wind facility in the fleet. The Company is maintaining communication with all key stakeholders and is keeping them fully apprised of the situation. The Company is actively evaluating any options that may be available to recover these costs from third parties and insurance.

As a result of the determination that all 50 foundations require replacement, as well as certain resulting amendments to applicable insurance policies, the Company's operating subsidiary, Kent Hills Wind LP, has provided notice to BNY Trust Company of Canada, as trustee (the "Trustee"), for the approximately $221 million outstanding non-recourse project bonds (the "KH Bonds") secured by, among other things, the Kent Hills 1, 2 and 3 wind facilities, that events of default may have occurred under the trust indenture governing the terms of the KH Bonds. Upon the occurrence of any event of default, holders of more than 50 per cent of the outstanding principal amount of the KH Bonds have the right to direct the Trustee to declare the principal and interest on the KH Bonds and all other amounts due, together with any make-whole amount as at Dec. 31, 2021 — $39 million, to be immediately due and payable and to direct the Trustee to exercise rights against certain collateral. The Company is in discussions with the Trustee and holders of the KH Bonds to negotiate required waivers and amendments while the Company works to remedy the matters described in the notice. Although the Company expects that it will reach agreement with the Trustee and holders of the KH Bonds with respect to terms of an acceptable waiver and amendment, there can be no assurance that the Company will receive such waivers and amendments. Accordingly, the Company has classified the entire carrying value of the KH Bonds as a current liability as at Dec. 31, 2021.

Investor Day

On Sept. 28, 2021, TransAlta held our 2021 Investor Day and announced our Clean Electricity Growth Plan. The Company has established targets to deliver 2 GW of incremental renewables capacity with a targeted investment of $3 billion by 2025. TransAlta will accelerate its growth with a focus on customer-centred renewables and storage through the execution of its 3 GW development pipeline. Please see the Accelerated Clean Electricity Growth Plan section of this MD&A.

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[3] *Average annual EBITDA is not defined and has no standardized meaning under IFRS, and is forward-looking. Please refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further discussion.*

Retirement of Sundance Unit 4, Keephills Unit 1 and Sundance Unit 5 Coal-Fired Units

The Company announced, during its recent Investor Day, its decision to suspend the Sundance Unit 5 repowering project and retire Keephills Unit 1 on Jan. 1, 2022 and Sundance Unit 4 in 2022.

On July 29, 2021, in accordance with applicable regulatory requirements, the Company gave notice to the AESO of its intention to retire the currently mothballed coal-fired Sundance Unit 5 effective Nov. 1, 2021, and to terminate the associated transmission service agreement. Refer to the Clean Energy Transition section within the Description of the Business section of this MD&A for additional details on these thermal assets.

TransAlta Achieves Full Phase-Out of Coal in Canada

During the year, the Company completed the full conversion of Keephills Unit 2, Keephills Unit 3 and Sundance Unit 6 from thermal coal to natural gas. Keephills Unit 2, Keephills Unit 3 and Sundance Unit 6 will maintain the same generator nameplate capacity of 395 MW, 463 MW and 401 MW, respectively. These conversion to gas projects will reduce our CO_2 emissions by more than half and completes our plan to generate 100 per cent clean electricity in Alberta by the end of 2021. As of Dec. 31, 2021, the Company has fully transitioned to natural gas in Canada.

Highvale Mine Impairment

During the third quarter of 2020, the Board approved the accelerated shutdown of the Highvale mine by the end of 2021 and, accordingly, the useful life of the related assets was adjusted to align with the Company's conversion to gas plans. During the third quarter of 2021, with all of TransAlta's remaining coal-fired units having been converted, in the process of being converted to natural gas or being retired, the Highvale mine was no longer considered to be providing significant economic benefit to the Alberta Merchant CGU and was removed from the CGU. This resulted in an impairment being recognized during 2021 of $195 million. Effective Dec. 31, 2021, the mine has entered its reclamation phase.

Announced Common Dividend Increase

On Sept. 28, 2021, the Company announced that the Board approved an 11 per cent increase on its common share dividend and declared a dividend of $0.05 per common share paid on Jan. 1, 2022, to shareholders of record at the close of business on Dec. 1, 2021. The quarterly dividend of $0.05 per common share represents an annualized dividend of $0.20 per common share.

Northern Goldfields Solar Project

On July 29, 2021, TransAlta Renewables announced that Southern Cross Energy ("SCE"), a subsidiary of the Company and an entity in which TransAlta Renewables owns an indirect economic interest, had reached an agreement to provide BHP Billiton Nickel West Pty Ltd. ("BHP") with renewable electricity to its Goldfields-based operations through the construction of the Northern Goldfields Solar Project. The project consists of the 27 MW Mount Keith Solar Farm, 11 MW Leinster Solar Farm, 10 MW/5MWh Leinster Battery Energy Storage System and interconnecting transmission infrastructure, all of which will be integrated into our existing 169 MW Southern Cross Energy North remote network in Western Australia. Construction commenced in the first quarter of 2022 with completion of the projects expected in the second half of 2022. Total construction capital for the project is estimated at approximately AU$69 million to AU$73 million. The project is expected to generate average annual EBITDA[4] of approximately AU$9 million to AU$10 million.

On Oct. 22, 2020, SCE replaced and extended its current PPA with BHP. SCE is composed of four generation facilities with a combined capacity of 245 MW in the Goldfields region of Western Australia. The new agreement was effective Dec. 1, 2020, and replaces the previous contract that was scheduled to expire Dec. 31, 2023. The amendment to the PPA extends the term to Dec. 31, 2038, and provides SCE with the exclusive right to supply thermal and electrical energy from the Southern Cross Facilities for BHP's mining operations located in the Goldfields region of Western Australia. The extension will provide SCE a return on new capital investments, which will be required to support BHP's future power requirements and recently announced emission reduction targets. The amendments within the PPA also provide BHP with participation rights in integrating renewable electricity generation, including solar and wind, with energy storage technologies, subject to the satisfaction of certain conditions. In addition to the Northern Goldfields Solar Project, evaluation of further renewable energy supply and carbon emissions reduction initiatives under the extended PPA with BHP are underway, including wind generation and lower emission firming generation to support BHP's future power requirements.

[4] *Average annual EBITDA is not defined and has no standardized meaning under IFRS, and is forward-looking. Please refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further discussion.*

Sale of the Pioneer Pipeline

On June 30, 2021, the Company closed the sale of the Pioneer Pipeline to ATCO Gas and Pipelines Ltd. ("ATCO") for the aggregate sale price of $255 million. The net cash proceeds to TransAlta from the sale of its 50 per cent interest was approximately $128 million. Pioneer Pipeline has been integrated into the NOVA Gas Transmission Ltd. ("NGTL") and ATCO Alberta natural gas transmission systems to provide reliable natural gas supply to the Company's power generation stations at Sundance and Keephills. As part of the transaction, TransAlta has entered into additional long-term gas transportation agreements with NGTL for new and existing transportation service of 400 TJ per day by the end of 2023.

Sarnia Cogeneration Facility Contract Extension

On May 12, 2021, the Company executed an Amended and Restated Energy Supply Agreement with one of its large industrial customers at the Sarnia cogeneration facility, which provides for the supply of electricity and steam. This agreement will extend the term of the original agreement from Dec. 31, 2022 to Dec. 31, 2032. The agreement provides that if the Company is unable to enter into a new contract with the Ontario Independent Electricity System Operator ("IESO") or enter into agreements with its other industrial customers at the Sarnia cogeneration facility that extend past Dec. 31, 2025, then the Company has the option to provide notice of termination in 2022 that would terminate the Amended and Restated Energy Supply Agreement four years following such notice. The Company is in active discussions with the three other existing industrial customers regarding extensions to their supply of electricity and steam from the Sarnia cogeneration facility on comparable terms. The current contract with the IESO in respect of the Sarnia cogeneration facility expires on Dec. 31, 2025. On July 19, 2021, the IESO released its Annual Acquisition Report, which included draft details for medium- and long-term procurement mechanisms for capacity for 2026 and beyond for existing and new generation. The medium-term procurement process is scheduled to be run in 2022. The Company plans to bid into the process, seeking to secure a contract extension for the Sarnia cogeneration facility following the end of the current contract.

Garden Plain Wind Project

On May 3, 2021, the Company announced that it entered into a long-term PPA with Pembina pursuant to which Pembina has contracted for the renewable electricity and environmental attributes for 100 MW of the 130 MW Garden Plain project. Under a separate agreement, Pembina has the option to purchase a 37.7 per cent interest in the project (49 per cent of the quantity under the PPA). The option must be exercised no later than 30 days after the commercial operational date. TransAlta would remain the operator of the facility and earn a management fee if Pembina exercises this option. Garden Plain will be located approximately 30 kilometres north of Hanna, Alberta. Construction activities started in the fall of 2021 with completion of the project expected in the second half of 2022. Total construction capital for the project is estimated at approximately $195 million. The project is expected to contribute between $14 million and $18 million of average annual EBITDA[5].

TransAlta Renewables is Named on the Best 50 Corporate Citizens List

During the second quarter of 2021, TransAlta Renewables was recognized by Corporate Knights as one of the Best 50 Corporate Citizens for 2021. The Best 50 Corporate Citizens list evaluates and ranks Canadian corporations against a set of 24 key performance indicators covering ESG indicators relative to their industry peers and using publicly available information. The Company is committed to continuous improvement on key ESG issues and to ensuring its economic value creation is balanced with a value proposition for the environment and its communities.

Equity, Diversity and Inclusion Program

On May 3, 2021, TransAlta announced that it received certification from a third party that specializes in measuring and tracking equity, diversity and inclusion ("ED&I") metrics for organizations, due to its continued commitment to and meaningful performance on ED&I in the workplace. The Company developed a five-year ED&I strategy that was approved by the Board in August 2021, and is now executing the first year of that ED&I strategy.

[5] *Average annual EBITDA is not defined and has no standardized meaning under IFRS, and is forward-looking. Please refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further discussion.*

Sustainability-Linked Loan

In March 2021, TransAlta extended its $1.3 billion syndicated credit facility to June 30, 2025, and converted the facility into a Sustainability-Linked Loan ("SLL"). The facility's financing terms will align the cost of borrowing to TransAlta's GHG emission reductions and gender diversity targets, which are part of the Company's overall ESG strategy. The SLL will have a cumulative pricing adjustment to the borrowing costs on the facilities and a corresponding adjustment to the standby fee (the "Sustainability Adjustment"). Depending on performance against interim targets that have been set for each year of the credit facility term, the Sustainability Adjustment is structured as a two-way mechanism and could move either up, down or remain unchanged for each sustainability performance target based on performance. The SLL further underscores TransAlta's dedication to sustainability, including ED&I and emissions reduction.

Mangrove Claim

On April 23, 2019, the Mangrove Partners Master Fund Ltd. ("Mangrove") commenced an action in the Ontario Superior Court of Justice naming the Company, the members of the Board of the Company on such date, and Brookfield BRP Holdings (Canada) ("Brookfield") as defendants. Mangrove was seeking to set aside the 2019 Brookfield transaction. The parties reached a confidential settlement and the action was discontinued in the Ontario Superior Court of Justice on April 30, 2021.

Fortescue Metals Group Ltd. ("FMG") Dispute at South Hedland Power Station

On May 2, 2021, the Company entered into a conditional settlement with FMG. The settlement was concluded and the actions were formally dismissed in the Supreme Court of Western Australia on Dec. 7, 2021. The settlement amount has been recorded as revenue in the fourth quarter of 2021, while all other balances previously provided for have been reversed. The settlement has resulted in FMG continuing as a customer of the South Hedland facility.

Keephills 1 Superheater Force Majeure

Keephills Unit 1 was taken offline from March 17, 2015, to May 17, 2015, as a result of a large leak in the secondary superheater. TransAlta claimed force majeure under the PPA. ENMAX Energy Corporation ("ENMAX"), the purchaser under the PPA at the time, did not dispute the force majeure but the Balancing Pool attempted to do so, seeking to recover $12 million in capacity payment charges it paid to TransAlta while the unit was offline. The parties reached a confidential settlement on April 21, 2021, and this matter is now resolved.

TransAlta Renewables Acquisitions

The Company completed the sale of its 100 per cent direct interest in the 206 MW Windrise wind project ("Windrise") to TransAlta Renewables on Feb. 26, 2021, for $213 million. The remaining construction costs for Windrise were paid by TransAlta Renewables. On Nov. 10, 2021, Windrise achieved commercial operations. On Dec. 6, 2021, the Company's indirect wholly owned subsidiary, Windrise Wind LP, secured green bond financing by way of private placement for $173 million. The bonds will be amortizing and will bear interest from their date of issue at a rate of 3.41 per cent per annum and mature on Sept. 30, 2041.

On April 1, 2021, the Company completed the sale of its 100 per cent economic interest in the 29 MW Ada cogeneration facility ("Ada") and its 49 per cent economic interest in the 137 MW Skookumchuck wind facility ("Skookumchuck") to TransAlta Renewables for $43 million and $103 million, respectively. Both facilities are fully operational. Pursuant to the transaction, a TransAlta subsidiary owns Ada and Skookumchuck directly and has issued to TransAlta Renewables tracking preferred shares reflecting its economic interest in the facilities. The Ada facility is under a PPA until 2026. The Skookumchuck wind facility is contracted under a PPA until 2040 with an investment grade counterparty.

Normal Course Issuer Bid

On May 25, 2021, the Toronto Stock Exchange ("TSX") accepted the notice filed by the Company to implement a normal course issuer bid ("NCIB") for a portion of our common shares. Pursuant to the NCIB, TransAlta may repurchase up to a maximum of 14,000,000 common shares, representing approximately 7.16 per cent of its public float of common shares as at May 18, 2021. 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, 2021, and ends on May 30, 2022, 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.

No common shares were repurchased under the current or previous NCIB in 2021.

Management Changes

On March 31, 2021, Dawn Farrell retired from the Board and as President and Chief Executive Officer of the Company. John Kousinioris succeeded Mrs. Farrell as President and Chief Executive Officer and joined the Board on April 1, 2021. Prior to his appointment as Chief Executive Officer of TransAlta, Mr. Kousinioris held the roles of Chief Operating Officer, Chief Growth Officer and Chief Legal and Compliance Officer and Corporate Secretary with the Company.

On April 30, 2021, Brett Gellner, our Chief Development Officer, retired after almost 13 years with TransAlta. Mr. Gellner continues to serve on the Board of Directors of TransAlta Renewables as a non-independent director.

Board of Director Changes

On May 4, 2021, the Company announced the election of four new directors: Mr. Thomas O'Flynn, Ms. Laura W. Folse, Mr. Jim Reid and Ms. Sarah Slusser, who each bring diverse expertise and new perspectives to the Board. Mr. Richard Legault, Mr. Yakout Mansour and Mrs. Georgia Nelson did not stand for re-election and retired from the Board immediately following the annual shareholder meeting on May 4, 2021.

COVID-19

The World Health Organization declared a Public Health Emergency of International Concern relating to COVID-19 on Jan. 30, 2020, which they subsequently declared, on March 11, 2020, as a global pandemic.

The Company continues to operate under its business continuity plan, which is focused on ensuring that: (i) employees who can work remotely do so; and (ii) employees who operate and maintain our facilities, and who are not able to work remotely, are able to work safely and in a manner that ensures their health and safety. TransAlta has adopted local public health authority and government guidelines in all jurisdictions in which we operate to promote the health and safety of all employees and contractors with our health and safety protocols. All of TransAlta's offices and sites follow health screening and social distancing protocols, including personal protective equipment. Employees can be exempted from rapid testing if they are able to provide proof of vaccination. Further, TransAlta maintains travel limitations that are aligned to local jurisdictional guidance, enhanced cleaning procedures, revised work schedules, contingent work teams and the reorganization of processes and procedures to minimize any workplace transmission of the virus.

Notwithstanding the challenges associated with the pandemic, all of our facilities continue to remain fully operational and are capable of meeting our customers' needs, with the exception of the Kent Hills 1 and 2 wind facilities, which as described above, is not related to the pandemic. The Company continues to work and serve all of our customers and counterparties under the terms of their contracts. We have not experienced interruptions to service requirements as a result of COVID-19. Electricity and steam supply continue to remain a critical service requirement to all of our customers and have been deemed an essential service in our jurisdictions.

The Company continues to maintain a strong financial position due in part to its long-term contracts and hedged positions, and its ample financial liquidity.

The Board and management have been monitoring the evolution of the pandemic and are continually assessing its impact to the safety of the Company's employees, operations, supply chains and customers as well as, more generally, to our existing capital projects, and the business and affairs of the Company. Potential impacts of the pandemic on the business and affairs of the Company include, but are not limited to: (i) potential interruptions of production; (ii) supply chain disruptions; (iii) unavailability of employees; (iv) potential delays in capital projects; (v) increased credit risk with counterparties and increased volatility in commodity prices; as well as (vi) increased volatility in the valuation of financial instruments. In addition, the broader impacts to the global economy and financial markets could have potential adverse impacts on the availability of capital for investment and the demand for power and commodity pricing.

Strategic Investment by Brookfield

On March 22, 2019, the Company entered into an agreement (the "Investment Agreement") whereby Brookfield agreed to invest $750 million in the Company through the purchase of exchangeable securities, which are exchangeable by Brookfield into an equity ownership interest in certain of TransAlta's Alberta Hydro Assets in the future at a value based on a multiple of the Alberta Hydro Assets' future-adjusted EBITDA.

On May 1, 2019, Brookfield invested the initial tranche of $350 million in exchange for seven per cent unsecured subordinated debentures due May 1, 2039. On Oct. 30, 2020, Brookfield invested the second tranche of $400 million in consideration for redeemable, retractable first preferred shares. The proceeds from the first and second tranche were used to accelerate our conversion to gas program. In addition, the proceeds from the second tranche of the financing will be used to fund other growth initiatives and for general corporate purposes.

Under the terms of the Investment Agreement, Brookfield committed to purchase TransAlta common shares on the open market to increase its share ownership in TransAlta to not less than nine per cent. At Dec. 31, 2021, Brookfield, through its affiliates, held, owned or had control over an aggregate of 35,425,696 common shares, representing approximately 13.1 per cent of the issued and outstanding common shares, calculated on an undiluted basis. In connection with the Investment Agreement, Brookfield is entitled to nominate two directors for election to the Board.

In accordance with the terms of the Investment Agreement, TransAlta formed a Hydro Assets Operating Committee consisting of two representatives from Brookfield and two representatives from TransAlta to collaborate in connection with the operation and maximization of the value of the Alberta Hydro Assets. In connection with this, the Company has committed to pay Brookfield an annual fee of $1.5 million for six years beginning May 1, 2019, which is recognized in the OM&A expense on the Consolidated Statements of Earnings (Loss).

Centralia Unit 1 and 2 Retirement

In 2011, Washington State passed the TransAlta Energy Transition Bill (chapter 180, Laws of 2011) (the "Bill'') allowing the Centralia thermal facility to comply with the state's GHG emissions performance standards by ceasing coal generation in one of its two boilers by the end of 2020, and the other by the end of 2025. The Bill removed restrictions that had previously been imposed on the facility limiting the duration of new contracts from the facility and limiting the technology that the facility would be required to implement for nitrogen oxide ("NO_x") controls. Centralia Unit 1 was retired from service effective Dec. 31, 2020, as planned. The Centralia Unit 2 is set to shut down at the end of 2025.

TEC Hedland Pty Ltd. Secures AU$800 Million Financing

On Oct. 22, 2020, TEC Hedland Pty Ltd. ("TEC"), a subsidiary of the Company, closed an AU$800 million senior secured note offering, by way of a private placement, which is secured by, among other things, a first ranking charge over all assets of TEC (the "TEC Offering"). The TEC Offering bears interest at 4.07 per cent per annum, payable quarterly and maturing on June 30, 2042, with principal payments starting on March 31, 2022. The TEC Offering has a rating of BBB by Kroll Bond Rating Agency.

TransAlta Renewables has received $480 million (AU$515 million) of the proceeds from the TEC Offering through the redemption of certain intercompany structures. An additional AU$200 million was loaned to TransAlta Renewables by TransAlta Energy (Australia) Pty Ltd., which is a subsidiary of TransAlta. The loan bears interest at 4.32 per cent and will be repaid by Oct. 23, 2022, or on demand. The remaining proceeds from the TEC Offering were set aside for required reserves and transaction costs. TransAlta Renewables used a portion of the proceeds from the redemption and the intercompany loan to repay existing indebtedness on its credit facility and to acquire the asset and economic interests noted above.

Segmented Financial Performance and Operating Results

Segmented Disclosures

Segmented information is prepared on the same basis that the Company manages the business, evaluates financial results and makes key operating decisions. Refer to the Description of the Business section of this MD&A for explanation of the reporting segment changes.

The primary changes are the elimination of the Alberta Thermal and the Centralia segments, and the reorganization of the North American Gas and Australia Gas segments into a new "Gas" segment. The Alberta Thermal facilities that have been converted to gas have been included in the Gas segment. The remaining assets previously included in Alberta Thermal, including the mining assets and those facilities not converted to gas and the remaining Centralia unit, are included in a new "Energy Transition" segment. No changes were made to the Hydro, Wind and Solar, Energy Marketing or the Corporate and Other segments. Prior years' metrics were adjusted to be comparable to the new segments.

Consolidated Results

The following table reflects the generation and summary financial information on a consolidated basis for the year ended Dec. 31:

	LTA generation (GWh)(1)			Actual production (GWh)(2)			Adjusted EBITDA(3)		
For the year ended Dec. 31	**2021**	2020	2019	**2021**	2020	2019	**2021**	2020	2019
Hydro	**2,030**	2,030	2,030	**1,936**	2,132	2,045	**322**	105	110
Wind and Solar	**4,345**	3,916	3,549	**3,898**	4,069	3,355	**262**	248	231
Renewables	**6,375**	5,946	5,579	**5,834**	6,201	5,400	**584**	353	341
Gas				**10,565**	10,780	11,819	**494**	367	403
Energy Transition				**5,706**	7,999	11,852	**133**	175	227
Energy Marketing							**137**	113	89
Corporate and Other							**(85)**	(81)	(76)
Total				**22,105**	24,980	29,071	**1,263**	927	984
Total earnings (loss) before income taxes							**(380)**	(303)	193

(1) Long-term average production ("LTA (GWh)") is calculated based on our portfolio as at Dec. 31, 2021, 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 30-35 years for the Wind and Solar segment and 36 years for Hydro segment. LTA (GWh) for Energy Transition is not considered for these facilities as we are currently transitioning these units completely by the end of 2025 and the LTA (GWh) for Gas is not considered as it is largely dependent on market conditions and merchant demand.

(2) Actual production levels are compared against the long-term average to highlight the impact of an important factor that affects the variability in our business results. In the short term, for each segment for Hydro, Wind and Solar, the conditions will vary from one period to the next and over time facilities will continue to produce in line with their long-term averages, which have proven to be reliable indicators of performance.

(3) This item is not defined and has no standardized meaning under IFRS. Please refer to below in this MD&A for further discussion of this item, 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.

Hydro

Year ended Dec. 31	2021	2020	2019
Gross installed capacity (MW)	**925**	925	925
LTA (GWh)	**2,030**	2,030	2,030
Availability (%)	**92.4**	93.2	95.9
Production			
Energy contract			
Alberta Hydro Assets (GWh)(1)	**—**	1,703	1,653
Other Hydro energy (GWh)(1)	**434**	353	331
Energy merchant			
Alberta Hydro Assets (GWh)	**1,502**	—	—
Other Hydro energy (GWh)	**—**	76	61
Total energy production (GWh)	**1,936**	2,132	2,045
Ancillary service volumes (GWh)(4)	**2,897**	2,857	2,978
Alberta Hydro Assets(1)	**185**	87	101
Other Hydro Assets and other revenue(1)(2)	**42**	45	44
Capacity payments(3)	**—**	60	57
Alberta Hydro ancillary services(4)	**160**	66	90
Net payment relating to Alberta Hydro PPA(5)	**(4)**	(106)	(136)
Revenues	**383**	152	156
Fuel and purchased power	**16**	8	7
Gross margin	**367**	144	149
Operations, maintenance and administration	**42**	37	36
Taxes, other than income taxes	**3**	2	3
Adjusted EBITDA	**322**	105	110
Supplemental Information:			
Gross revenues per MWh			
Alberta Hydro Assets energy ($/MWh)	**123**	51	61
Alberta Hydro Assets ancillary ($/MWh)	**55**	23	30
Sustaining capital	**26**	20	14

(1) Alberta Hydro Assets include 13 hydro facilities on the Bow and North Saskatchewan river systems included under the PPA legislation. These PPAs expired Dec. 31, 2020. Other hydro facilities include our hydro facilities in BC and Ontario and the hydro facilities in Alberta not included in the legislated PPAs and transmission revenues.
(2) Other revenue includes revenues from our non-PPA hydro facilities, our transmission business and other contractual arrangements including the flood mitigation agreement with the Alberta government and black start services.
(3) Capacity payments include the annual capacity charge as described in the Power Purchase Arrangements Determination Regulation AR 175/2000, available from Alberta Queen's Printer. The PPA expired on Dec. 31, 2020.
(4) Ancillary services as described in the AESO Consolidated Authoritative Document Glossary.
(5) The net payment relating to the Alberta Hydro PPA represents the Company's financial obligations for notional amounts of energy and ancillary services in accordance with the Alberta Hydro PPA that expired on Dec. 31, 2020.

2021

Availability for 2021 decreased compared to 2020, primarily due to higher planned and unplanned outages.

Production for 2021 decreased by 196 GWh compared to 2020, mainly due to higher planned outages and lower precipitation.

Ancillary service volumes for 2021 increased by 40 GWh compared to 2020, in line with our expectations.

Adjusted EBITDA for 2021 increased by $217 million compared to 2020. Effective Jan. 1, 2021, with the expiration of the Alberta PPA for our Alberta Hydro Assets, these facilities began operating on a merchant basis in the Alberta power market. This eliminated the net payment obligations under the Alberta PPA. With strong availability during periods of market volatility, the Company captured higher energy and ancillary service revenue, partially offset by increased costs related to portfolio management services, dam safety staffing, dredging and station services.

Sustaining capital expenditures for 2021 were $6 million higher than in 2020, due to higher planned outages in 2021.

2020

Availability for 2020 decreased compared to 2019, primarily due to higher planned and unplanned outages.

Production for 2020 increased by 87 GWh over 2019, primarily due to higher water resources.

Ancillary service volumes for 2020 decreased by 121 GWh compared to 2019. This was primarily due to the AESO procuring lower ancillary volumes in 2020. Ancillary volumes were impacted by weaker market conditions, partially due to COVID-19 and reduced industrial demand in Alberta.

In 2020, Alberta Hydro energy revenue per MWh of production decreased by approximately $10 per MWh, compared to 2019, as result of lower merchant prices in Alberta. In 2020, Alberta Hydro ancillary revenue per MWh of production decreased by approximately $7 per MWh, compared to 2019. Lower realized prices were primarily due to unfavourable market conditions in Alberta in 2020.

Adjusted EBITDA for 2020 decreased by $5 million compared to 2019, from lower revenues partially offset by recoveries allocated by the AESO related to the AESO transmission line loss proceeding.

Sustaining capital expenditures for 2020 were $6 million higher than in 2019, due to higher planned outages in 2020.

Wind and Solar

Year ended Dec. 31	2021	2020	2019
Gross installed capacity (MW)[(1)]	**1,906**	1,572	1,495
LTA (GWh)	**4,345**	3,916	3,549
Availability (%)	**91.9**	95.1	95.0
Contract production (GWh)	**2,850**	2,871	2,395
Merchant production (GWh)	**1,048**	1,198	960
Total production (GWh)	**3,898**	4,069	3,355
Revenues[(2)]	**348**	334	295
Fuel and purchased power	**17**	25	16
Gross margin[(2)]	**331**	309	279
Operations, maintenance and administration	**59**	53	50
Taxes, other than income taxes	**10**	8	8
Net other operating income[(3)]	**—**	—	(10)
Adjusted EBITDA	**262**	248	231
Supplemental information:			
Sustaining capital	**13**	13	13

(1) The 2021 gross installed capacity includes 206 MW for the Windrise wind facility and 4 MW for the Oldman Wind facility, which were added in 2021. The 2021 and 2020 gross installed capacity includes 10 MW for the WindCharger battery storage facility and 67 MW for our proportionate share of the Skookumchuck wind facility.
(2) 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.
(3) Relates to insurance proceeds included in net other operating income.

2021

Availability for the year ended Dec. 31, 2021, decreased compared to 2020, primarily as a result of the unplanned outage at the Kent Hills 1 and 2 wind facilities.

Production for the year ended 2021, decreased 171 GWh compared to 2020, and was impacted by lower wind resources in Eastern Canada and in the US and the unplanned outage at the Kent Hills 1 and 2 wind facilities, which was partially offset by a full year of production from the Skookumchuck wind facility, the commissioning of the Windrise wind facility, and the acquisition of the North Carolina Solar facility.

Adjusted EBITDA for 2021 increased by $14 million compared to 2020, primarily due to higher merchant pricing in Alberta, a full year of operations from the Skookumchuck wind facility and the WindCharger battery storage facility as well as incremental value from the newly commissioned or acquired assets in 2021: consisting of the Windrise wind facility and the North Carolina Solar facility. Also, fuel and purchased power costs were lower in 2021 due to the AESO transmission line loss recorded in 2020. Adjusted EBITDA was negatively impacted by lower wind resources in Eastern Canada and the US, the unplanned outage at the Kent Hills 1 and 2 wind facilities and the weakening US dollar relative to the Canadian dollar.

Sustaining capital expenditures for 2021 were consistent with 2020.

2020

Availability for the year ended Dec. 31, 2020, was consistent with 2019, which was in line with our expectations.

Production for the year ended Dec. 31, 2020, increased 714 GWh, mainly due to the Big Level and Antrim wind facilities commencing commercial operations in December 2019 and strong wind resources across all regions in 2020, in particular at the Alberta wind facilities.

Adjusted EBITDA for 2020 increased by $17 million compared to 2019, primarily due to the addition of the Big Level and Antrim wind facilities and higher production, partially offset by insurance proceeds received in 2019, lower Alberta pricing and the planned expiry of certain wind power production incentives in 2019. In addition, during 2020, the AESO began issuing invoices pertaining to the AESO transmission line loss. Wind and Solar were allocated $8 million in costs in 2020, which has been reflected in fuel and purchased power within the same year.

Sustaining capital expenditures for 2020 were consistent with 2019.

Gas

Year ended Dec. 31	2021	2020	2019
Gross installed capacity (MW)(1)	**3,084**	3,084	3,049
Availability (%)	**85.7**	87.7	92.8
Contract production (GWh)	**3,622**	7,280	8,101
Merchant production (GWh)(2)	**7,084**	3,698	3,810
Purchased power (GWh)(2)	**(141)**	(198)	(92)
Total production (GWh)	**10,565**	10,780	11,819
Revenues(3)	**1,132**	848	887
Fuel and purchased power(3)	**374**	221	230
Carbon compliance	**118**	120	138
Gross margin(3)	**640**	507	519
Operations, maintenance and administration(3)	**173**	166	162
Taxes, other than income taxes	**13**	13	9
Net other operating income(3)	**(40)**	(39)	(41)
Termination of Sundance B and C PPAs	**—**	—	(14)
Adjusted EBITDA	**494**	367	403
Supplemental information:			
Sustaining capital	**128**	87	33

(1) 2021 and 2020 includes 29 MW for the acquisition of the Ada facility.
(2) Purchased power used for dispatch optimization has been separated from merchant production in the current year. Comparable periods have been adjusted to reflect this change.
(3) For details of the adjustments to revenues, fuel and purchased power, operations, maintenance and administration and net other operating income included in adjusted EBITDA, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

The Gas Segment is a new segment as described in the Segmented Financial Performance and Operating Results section of this MD&A. Included in the Gas segment is the previous North American Gas segment, Australian Gas segment and the facilities from the previous Alberta Thermal segment converted to gas.This includes Sheerness Unit 1 and 2, Keephills Unit 2 and 3 and Sundance Unit 6. Previous periods have been adjusted to be comparable to the new segment.

2021

Availability for the year ended Dec. 31, 2021, decreased compared to 2020, primarily as a result of an increase in unplanned outages and planned boiler conversions of Keephills Unit 2, Keephills Unit 3, and Sheerness Unit 1 in Alberta, partially offset by higher availability of Sundance 6 with the gas conversion completed in 2020.

Production for the year ended Dec. 31, 2021, decreased by 215 GWh compared to 2020, mainly due to higher portfolio optimization activities in Alberta and lower customer loads in Australia, partially offset by higher demand in our other facilities and incremental production from a full year of operations at the Ada cogeneration facility.

Adjusted EBITDA for the year ended Dec. 31, 2021, increased by $127 million compared to 2020, primarily due to higher merchant pricing in the Alberta market, the South Hedland PPA contract settlement and incremental production from a full year of operations at our Ada cogeneration facility, partially offset by an increase in fuel, unplanned short-term steam supply outages at our Sarnia cogeneration facility, higher OM&A costs related to the BHP pass-through projects and legal fees related to the South Hedland PPA contract settlement.

Sustaining capital expenditures for the year ended Dec. 31, 2021, increased by $41 million mainly due to major maintenance costs associated with conversion to natural gas outages of Keephills Unit 2 and Unit 3 and Sheerness Unit 1, planned major maintenance at the Australian gas facilities, and the purchase of an additional engine at the South Hedland facility.

2020

Availability for the year ended Dec. 31, 2020, decreased compared to 2019, due to the Sundance Unit 6 planned turnaround and conversion to gas, higher unplanned outages and derates.

Production for the year ended Dec. 31, 2020, decreased by 1,039 GWh compared to 2019, mainly due to lower availability, lower merchant production in Alberta and Ontario and lower customer demand in Australia, partially offset by the addition of the Ada cogeneration facility.

Adjusted EBITDA for the year ended Dec. 31, 2020, decreased by $36 million compared to 2019, due to lower revenues from lower realized merchant pricing in Alberta and lower production, higher fuel costs and $14 million related to the settlement on the Sundance B and C PPAs in 2019, partially offset by the addition of the Ada facility, deferral of legal costs, reduced staffing due to cost controls and the strengthening of the Australian dollar against the Canadian dollar.

Sustaining capital expenditures for the year ended Dec. 31, 2020, increased by $54 million mainly due to the major maintenance that occurred during the Sheerness dual-fuel conversion and the Sundance Unit 6 turnaround and planned major maintenance at the Southern Cross facility, partially offset by a reduction in sustaining capital associated with a major planned outage for Sarnia cogeneration facility in 2019.

Energy Transition

Year ended Dec. 31	2021	2020	2019
Gross installed capacity (MW)[(1)]	**1,472**	2,548	2,916
Availability (%)	**75.3**	82.6	78.7
Adjusted availability (%)[(2)]	**78.8**	91.3	84.2
Contract sales volume (GWh)	**3,329**	5,526	5,622
Merchant sales volume (GWh)	**6,052**	6,248	10,095
Purchased power (GWh)	**(3,675)**	(3,775)	(3,865)
Total production (GWh)	**5,706**	7,999	11,852
Revenues[(3)]	**728**	690	893
Fuel and purchased power[(3)]	**432**	352	499
Carbon compliance	**60**	48	77
Gross margin[(3)]	**236**	290	317
Operations, maintenance and administration[(3)]	**97**	106	124
Taxes, other than income taxes	**6**	9	8
Termination of Sundance B and C PPAs	**—**	—	(42)
Adjusted EBITDA	**133**	175	227
Supplemental information:			
Highvale mine reclamation spend	**6**	7	15
Centralia mine reclamation spend	**9**	7	11
Sustaining capital	**19**	22	69

(1) 2021 gross installed capacity excludes Centralia Unit 1 (670 MW retired on Dec. 31, 2020) and Sundance Unit 5 (406 MW) retired during the year. 2021 and 2020 excludes 368 MW from Sundance Unit 3, which retired during 2020.
(2) Adjusted for dispatch optimization.
(3) For details of the adjustments to revenues, fuel and purchased power and operations, maintenance and administration included in adjusted EBITDA, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

The Energy Transition segment is a new segment as described in the Segmented Financial Performance and Operating Results section of this MD&A. Included in the Energy Transition segment is the previous Centralia segment, mine assets and the previous Alberta Thermal segment facilities that were not converted to gas. This includes Keephills Unit 1 and Sundance Unit 4. Previous periods have been adjusted to be comparable to the new segment.

2021

Adjusted availability for the year ended Dec. 31, 2021, decreased compared to 2020 due to higher planned and unplanned outages at Centralia Unit 2 and Sundance Unit 4 related to derates.

Production decreased by 2,293 GWh for the year ended Dec. 31, 2021, compared to 2020, primarily due the planned retirement of Centralia Unit 1 and dispatch optimization of the Alberta assets.

Adjusted EBITDA decreased by $42 million for the year ended Dec. 31, 2021, compared to 2020, primarily due the planned retirement of Centralia Unit 1, higher fuel and purchased power due to unplanned outages at Centralia Unit 2, higher carbon compliance costs for the Alberta assets primarily due to an increase in carbon prices and the weakening of the US dollar relative to the Canadian dollar throughout the year, partially offset by dispatch optimization of the Alberta assets and lower OM&A as a result the planned retirement of Centralia Unit 1.

Mine reclamation spend for the Highvale and Centralia mines was mainly consistent compared to 2020.

Sustaining capital expenditures for the year ended Dec. 31, 2021, were $3 million lower than 2020 mainly due to reduction in planned outage work performed.

2020

Adjusted availability for the year increased compared to 2019 due to reduced forced outages at Centralia Unit 1 and lower planned outages at the Alberta sites.

Production decreased by 3,853 GWh in 2020 compared to 2019 mainly due to lower merchant pricing and Genesee 3 no longer being owned by the company. In 2020, both Centralia units were taken out of service in February and March as a result of seasonally lower prices in the Pacific Northwest, whereas in 2019 both units remained in service into April due to higher prices in the Pacific Northwest. In 2020, Genesee 3 was not included due to a 2019 ownership swap, resulting in the Company no longer owning a portion of the facility.

Adjusted EBITDA decreased by $52 million compared to 2019, primarily due to lower merchant production in Alberta due to unfavourable market conditions, a $42 million settlement related to the Sundance B and C PPAs in 2019, partially offset by dispatch optimization at Centralia in 2020 and from the increased cost of buybacks due to forced outages.

Mine reclamation spend decreased by $8 million for the Highvale mine and $4 million for the Centralia mine compared to 2019, mainly due to downsizing, an updated mine plan and the mine closure advancement for the Highvale Mine. In addition, due to COVID-19 in 2020, the mine reclamation spend was deferred to future years.

Sustaining capital expenditures for 2020 decreased by $47 million compared to 2019 mainly due to lower planned outage work performed in 2020 and lower mining equipment purchases and maintenance.

Energy Marketing

Year ended Dec. 31	2021	2020	2019
Revenues[1]	**173**	143	119
Operations, maintenance and administration	**36**	30	30
Adjusted EBITDA	**137**	113	89

(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.

2021

Adjusted EBITDA for 2021 increased by $24 million compared to 2020. Results were better primarily due to favourable short-term trading of both physical and financial power and natural gas products across all North American markets. This was partially offset by OM&A increases due to higher incentives related to stronger performance. The Energy Marketing team was able to capitalize on short-term market volatility in the markets in which we trade without materially changing the risk profile of the business unit.

2020

Adjusted EBITDA for 2020 increased by $24 million compared to 2019. Results were primarily from continued strong performance in both power and natural gas markets. Gains were realized from short-term strategies across various geographic regions aided by market and price volatility. The Energy Marketing team was able to capitalize on short-term arbitrage opportunities in the markets in which we trade without materially changing the risk profile of the business unit. OM&A spending for 2020 and 2019 was similar.

Corporate

Year ended Dec. 31	2021	2020	2019
Operations, maintenance, and administration	**84**	80	73
Taxes, other than income taxes	**1**	1	1
Net other operating loss	**—**	—	2
Adjusted EBITDA	**(85)**	(81)	(76)
Supplemental information:			
Total sustaining capital	**13**	14	12

2021

Adjusted EBITDA for the year ended Dec. 31, 2021, decreased by $4 million compared to 2020, primarily due to higher incentive payments, higher employee costs, higher insurance costs, and higher legal fees for settlement of outstanding legal issues, partially offset by the receipt of CEWS funding and realized gains from the total return swap. A portion of the settlement costs of our employee share-based payment plans is hedged by entering into total return swaps, which are cash settled every quarter. Excluding the impact of the total return swap, staffing costs increased due to additional headcount to support growth initiatives. As previously committed, the CEWS funding is being used to support incremental employment within the Company.

For the year ended Dec. 31, 2021, sustaining capital expenditures were consistent with 2020.

2020

Adjusted EBITDA for the year ended Dec. 31, 2020, decreased by $5 million compared to 2019, primarily due to realized gains and losses from the total return swap. A portion of the settlement cost of our employee share-based payment plans is fixed by entering into total return swaps, which are cash settled every quarter. Excluding the impact of the total return swap, Corporate overhead costs for 2020 decreased by $10 million compared to 2019, mainly due to lower legal fees, lower labour and reduced travel costs, partially offset by additional costs to support growth and development projects, centralization of shared services to the Corporate segment and additional costs incurred to support COVID-19 protocols.

For the year ended Dec. 31, 2020, sustaining capital expenditures were $2 million higher than 2019, mainly due to capital spend on information technology.

Fourth Quarter Highlights

Consolidated Financial Highlights

Three months ended Dec. 31	**2021**	2020
Adjusted availability (%)	**83.8**	87.1
Production (GWh)	**5,823**	7,704
Revenues	**610**	544
Fuel and purchased power	**272**	282
Carbon compliance	**39**	45
Operations, maintenance and administration	**124**	118
Adjusted EBITDA(1)	**270**	234
Loss before income taxes	**(32)**	(168)
Net loss attributable to common shareholders	**(78)**	(167)
Cash flow from operating activities	**54**	110
FFO(1)	**213**	161
FCF(1)	**106**	52
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(0.29)**	(0.61)
Dividends declared per common share(2)	**0.10**	0.09
Dividends declared per preferred share(3)	**0.25**	0.50
FFO per share(1,4)	**0.79**	0.59
FCF per share(1,4)	**0.39**	0.19

(1) These items are not defined and have no standardized meaning under IFRS. Please 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. See also the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.
(2) Dividends declared vary year over year due to timing of dividend declarations.
(3) Weighted average of the Series A, B, C, E and G preferred share dividends declared. Dividends declared vary year over year due to timing of dividend declarations.
(4) The weighted average number of common shares outstanding for the three months ended Dec. 31, 2021 was 271 million shares (2020 - 273 million shares).

Financial Highlights

During the fourth quarter of 2021, the Company completed the year with solid performance from our Alberta Electricity Portfolio. Hydro, Gas and the Energy Transition segments had high availability in Alberta during periods of peak pricing, which resulted from extreme cold weather and periods of province-wide planned and unplanned outages. The Alberta merchant portfolio was positioned to capture opportunities from these strong spot market conditions through both energy and ancillary services revenues.

Adjusted availability for the three months ended Dec. 31, 2021, was 83.8 per cent compared to 87.1 per cent for the same period in 2020. Higher unplanned outages at our Wind and Solar segment and Energy Transition segment were partially offset by lower unplanned and planned outages at our Hydro segment. Wind and Solar availability was impacted by the unplanned outages at Kent Hills 1 and 2 wind facilities. Energy Transition availability was impacted by unplanned outages in our Centralia Unit 2 facility and dispatch optimization in Alberta.

Production for the three months ended Dec. 31, 2021, was 5,823 GWh compared to 7,704 GWh for the same period in 2020. The decrease in production for the three-month period in 2021 was due to the planned retirement of Centralia Unit 1 and unplanned outage at Centralia Unit 2, lower availability, the outage at the Kent Hills 1 and 2 wind facilities, and lower wind resources in the Wind and Solar segment. This decrease in production was partially offset by incremental production at our North Carolina Solar facility, the Windrise and Skookumchuck wind facilities in the Wind and Solar segment, and higher production at our Ada and Sarnia facilities within our Gas segment.

Revenues for the three months ended Dec. 31, 2021, increased $66 million compared to the same period in 2020, mainly as a result of capturing higher realized prices within the Alberta market through our optimization and operating activities and the elimination of the net payment obligations under the Alberta Hydro PPA required in the prior period. Revenues further increased due to the addition of the North Carolina Solar facility and commercial operation of the Windrise wind facility in the Wind and Solar segment, in addition to increased revenue from the Ada facility within the Gas segment. These increases were partially offset by lower production in the Energy Transition, Hydro and Wind and Solar segments.

Fuel and purchased power costs decreased by $10 million in the three months ended Dec. 31, 2021, compared to the same period in 2020. In our Energy Transition segment, our costs increased compared to 2020 due to higher fuel transportation costs and the acquisition of higher-priced power to fulfil our contractual obligations during planned and unplanned outages during periods of higher merchant pricing at the Centralia facility and higher natural gas pricing within the Gas segment. This was partially offset by lower coal mine depreciation and coal inventory write-downs at the Highvale mine in the fourth quarter of 2021.

Carbon compliance costs decreased by $6 million in the three months ended Dec. 31, 2021, compared to the same period in 2020, due to reductions in GHG emissions stemming from changes in the fuel mix ratio as we operated more on natural gas and fired less with coal, partially offset by an increase in the carbon price per tonne.

OM&A expenses for the three months ended Dec. 31, 2021, increased by $6 million, compared to the same period in 2020, primarily due to increased staffing costs for growth and strategic initiatives and higher incentive costs.

Adjusted EBITDA for the three months ended Dec. 31, 2021, increased by $36 million compared with the same period in 2020, largely due to higher adjusted EBITDA in our Hydro and Gas segments, which was driven by higher realized prices in the Alberta market, partially offset by lower production at Centralia Unit 2 within our Energy Transition segment due to a transformer failure that has now been resolved and an unplanned outage at the Kent Hills 1 and 2 wind facilities.

Net loss attributable to common shareholders in the fourth quarter of 2021 was $78 million compared to net loss of $167 million in the same period of 2020, a decrease of $89 million. The net loss in 2021 was favourably impacted by lower depreciation and amortization expense related to asset retirements and impairments in our Gas and Energy Transition segments and higher adjusted EBITDA.

Cash flow from operating activities in the fourth quarter of 2021 decreased by $56 million compared with the same period in 2020, primarily due to changes in non-cash working capital.

FCF in the fourth quarter of 2021 was $106 million compared to $52 million in the same period of 2020, as a result of higher adjusted EBITDA due to higher realized prices in Alberta, settlement of provisions and lower sustaining capital expenditures, partially offset by higher distributions paid to subsidiaries' non-controlling interests.

Segmented Financial Performance and Operating Results for the Fourth Quarter

A summary of our adjusted EBITDA by segment and total loss before income taxes for the three months ended Dec. 31, 2021 and 2020 is as follows:

	Adjusted EBITDA	
Three months ended Dec. 31	**2021**	2020
Hydro	**67**	22
Wind and Solar	**76**	77
Gas[1]	**110**	92
Energy Transition[2]	**37**	42
Energy Marketing	**9**	23
Corporate and Other	**(29)**	(22)
Total adjusted EBITDA	**270**	234
Loss before income taxes	**(32)**	(168)

(1) Gas segment includes the segments previously known as Australian Gas and North American Gas and the coal generation assets converted to gas from the segment previously known as Alberta Thermal.
(2) Energy Transition segment includes the segment previously known as Centralia and the coal generation assets not converted to gas (including Sundance 4) and mining assets from the segment previously known as Alberta Thermal.

Adjusted EBITDA increased by $36 million for the fourth quarter of 2021, compared to 2020, primarily as a result of:

- Hydro results were $45 million higher due to increased revenues from higher merchant prices in Alberta. Effective Jan. 1, 2021, with the expiration of the PPA for the Alberta Hydro facilities, these facilities began operating on a merchant basis in the Alberta power market. This eliminated the net payment obligations under the Alberta PPA.
- Wind and Solar results were consistent compared to the prior period; results were impacted by the unplanned outage at the Kent Hills 1 and 2 wind facilities, which was partially offset by higher merchant pricing in Alberta and incremental value from newly commissioned or acquired assets such as the North Carolina Solar facility and the Windrise facility.
- Gas results were $18 million higher mainly due to higher merchant prices in Alberta and the South Hedland PPA contract settlement, partially offset by higher OM&A costs and legal fees.
- Energy Transition results were $5 million lower as a result of the retirement of Centralia Unit 1, unplanned outages at Centralia Unit 2 due to a transformer failure that has now been resolved, partially offset by dispatch optimization of Alberta assets.
- Energy Marketing results were in line with expectations, but lower than prior year by $14 million.
- Corporate costs were higher primarily due to higher incentive payments and higher staffing costs, partially offset by lower legal dispute settlement costs. Impacts from the total return swap on our share-based payment plans were higher in 2021 compared to 2020.

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, as 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 2021	Q2 2021	Q3 2021	**Q4 2021**
Revenues	642	619	850	**610**
Adjusted EBITDA	310	302	381	**270**
Earnings (loss) before income taxes	21	72	(441)	**(32)**
Cash flow from operating activities	257	80	610	**54**
FFO	211	250	297	**213**
Net earnings (loss) attributable to common shareholders	(30)	(12)	(456)	**(78)**
Net earnings (loss) per share attributable to common shareholders, basic and diluted(1)	(0.11)	(0.04)	(1.68)	**(0.29)**
	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Revenues	606	437	514	544
Adjusted EBITDA	220	217	256	234
Earnings (loss) before income taxes	46	(52)	(129)	(168)
Cash flow from operating activities	214	121	257	110
FFO	172	159	193	161
Net earnings (loss) attributable to common shareholders	27	(60)	(136)	(167)
Net earnings (loss) per share attributable to common shareholders, basic and diluted(1)	0.10	(0.22)	(0.50)	(0.61)

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

Reported net earnings, adjusted EBITDA and FFO are generally higher in the first and fourth quarters due to higher demand associated with the cold winter months in the markets in which we operate and lower planned outages.

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

- Acquisition of the North Carolina Solar facility in the fourth quarter of 2021;
- The unplanned outage at Kent Hills 1 and 2 wind facilities and Centralia Unit 2 in the fourth quarter of 2021;
- Sundance Unit 5 repowering was suspended in the third quarter of 2021 and retired during 2021;
- Gains relating to the sale of the Pioneer Pipeline in the second quarter of 2021 and gains on sale of Gas equipment in the third quarter of 2021;
- The unplanned outages at the Sarnia cogeneration facility in the second quarter of 2021;
- Alberta hydro facilities, Keephills Units 1 and 2 and Sheerness began operating on a merchant basis in the Alberta market effective Jan. 1, 2021;
- Revenues declined due to weaker market conditions in 2020 as a result of the COVID-19 pandemic and low oil prices;
- Sundance Unit 3 was retired in the third quarter of 2020;
- Accelerated plans to shutdown the Highvale Mine resulted in remaining future royalty payments being recognized as an onerous contract in the third quarter of 2021;
- Sheerness going off-coal has resulted in the remaining coal supply payments on the existing coal supply agreement being recognized as an onerous contract in the fourth quarter of 2020;
- Accelerated shutdown of the Highvale Mine, increased mine depreciation included in the cost of coal. Coal inventory write-downs incurred in the first three quarters of 2021 and third and fourth quarters of 2020;
- Coal-related parts and materials inventory write-downs incurred in the second and third quarters of 2021;
- The impact of the updated provision estimates for the transmission line loss rule during the first quarter of 2021 and the last three quarters of 2020;
- Significant foreign exchange gains in the last three quarters of 2020, which more than offset foreign exchange losses experienced during the first quarter of 2020;
- The effects of impairments and reversals during all periods shown;
- The effects of changes in decommissioning and restoration provisions for retired assets in all periods shown;
- The effects of changes in useful lives of certain assets during the third quarter of 2020; and
- Current tax expense increases since the fourth quarter of 2020, mainly due to the Energy Marketing segment and certain Hydro operations becoming taxable, increased valuation allowances taken on US deferred tax assets along with a decreased deferred tax recovery mainly due to increased revenues in 2021.

Financial Position

The following table highlights significant changes in the consolidated statements of financial position from Dec. 31, 2020, to Dec. 31, 2021:

Assets	Dec. 31, 2021	Dec. 31, 2020	Increase/(decrease)
Current assets			
Cash and cash equivalents	**947**	703	244
Trade and other receivables	**651**	583	68
Risk management assets	**308**	171	137
Inventory	**167**	238	(71)
Assets held for sale	**25**	105	(80)
Other current assets(1)	**99**	102	(3)
Total current assets	**2,197**	1,902	295
Non-current assets			
Risk management assets	**399**	521	(122)
Property, plant and equipment, net	**5,320**	5,822	(502)
Right-of-use assets	**95**	141	(46)
Other non-current assets(2)	**1,215**	1,361	(146)
Total non-current assets	**7,029**	7,845	(816)
Total assets	**9,226**	9,747	(521)
Liabilities			
Current liabilities			
Credit facilities, long-term debt and lease liabilities (current)	**844**	105	739
Other current liabilities(3)	**1,087**	830	257
Total current liabilities	**1,931**	935	996
Non-current liabilities			
Credit facilities, long-term debt and lease liabilities	**2,423**	3,256	(833)
Decommissioning and other provisions (long-term)	**779**	614	165
Risk management liabilities (long-term)	**145**	68	77
Deferred income tax liabilities	**354**	396	(42)
Other non-current liabilities(4)	**1,001**	1,042	(41)
Total non-current liabilities	**4,702**	5,376	(674)
Total liabilities	**6,633**	6,311	322
Equity			
Equity attributable to shareholders	**1,582**	2,352	(770)
Non-controlling interests	**1,011**	1,084	(73)
Total equity	**2,593**	3,436	(843)
Total liabilities and equity	**9,226**	9,747	(521)

(1) Includes restricted cash and prepaid expenses.
(2) Includes investments, long-term portion of finance lease receivables, intangible assets, goodwill, deferred income tax assets and other assets.
(3) Includes accounts payable and accrued liabilities, current portion of decommissioning and other provisions, current portion of contract liabilities, income taxes payable and dividends payable.
(4) Includes exchangeable securities, contract liabilities and defined benefit obligation and other long-term liabilities.

Significant changes in TransAlta's consolidated statements of financial position were as follows:

Working Capital

Including the current portion of long term debt and lease liabilities, the excess of current assets over current liabilities was $266 million as at Dec. 31, 2021 (2020 - $967 million). Our working capital decreased year over year mainly due to the reclassification of debt from long-term to current. Excluding the current portion of long-term debt and lease liabilities of $844 million, the excess of current assets over liabilities was $1,110 million as at Dec. 31, 2021 (2020 - $1,072 million), consistent with the previous year.

Current assets increased by $295 million to $2,197 million as at Dec. 31, 2021, from $1,902 million as at Dec. 31, 2020. Strong Alberta pricing has increased operating cash flow and receivables. In addition, a loan receivable relating to Kent Hills Wind LP of $55 million was reclassified as current as it matures in October 2022. This was partially offset by reductions in inventory of $71 million and in assets held for sale of $80 million. Inventory balances have declined with coal inventory write-downs and parts and material write-downs relating to the transition off of coal and the closure of the Highvale mine. Assets held for sale decreased with the closing of the Pioneer Pipeline sale during the year.

Current liabilities increased by $996 million from $935 million as at Dec. 31, 2020, to $1,931 million as at Dec. 31, 2021, mainly due to the reclassification to current of $510 million Senior Notes coming due in 2022 and the reclassification of the Kent Hills bond of $221 million as the KH Bonds may be in default at the end of the year. We currently expect to refinance the senior notes maturing in 2022. Management is in discussions with the Trustee and holders of the KH Bonds to negotiate waivers and amendments related to the KH Bonds.

Derivative financial instruments also contributed favourably to the working capital balance.

Non-Current Assets

Non-Current assets at Dec. 31, 2021 was $7,029 million, a decrease of $816 million from $7,845 million as at Dec. 31, 2020. The decrease was primarily due to the asset impairments that have occurred during the year. The Energy Transition segment recognized $345 million of asset impairment charges in the year as a result of the decision to suspend the Sundance Unit 5 repowering project and the planned retirements of Keephills Unit 1 and Sundance Unit 4. In addition, with the completion of the transition to gas of the Alberta coal fleet, the Highvale mine was removed from the Alberta Merchant CGU, which resulted in an impairment recognized on the remaining mine assets, further reducing the property, plant and equipment ("PP&E") balance by $195 million. These impacts were partially offset by the construction of the Windrise wind facility and Garden Plain wind project, as well as the acquisition of the North Carolina Solar facility.

During 2021, the Company completed the sale of the Pioneer Pipeline to ATCO and derecognized the right- of-use asset of $43 million relating to the natural gas transportation agreement that was terminated as part of the transaction.

Non-Current Liabilities

Non-Current liabilities as at Dec. 31, 2021, are $4,702 million, a decrease of $674 million from $5,376 million as at Dec. 31, 2020, mainly due to a $833 million decrease in long-term debt and lease liabilities related in most part to the reclassification of the Senior Notes and KH Bonds to current liabilities, derecognition of the lease liability on the termination of the natural gas transportation agreement and from scheduled principal repayments on long-term debt and lease liabilities. This was partially offset by a $120 million increase in the wind decommissioning provisions resulting from a review of a recent wind engineering study on the decommissioning of the wind sites. The change in estimate is unrelated to the tower failure identified in the fourth quarter of 2021. In addition, the Company had a $47 million increase related to the Sundance and Keephills facilities to reflect a change in the timing of the expected reclamation work resulting from asset retirements and change in useful lives.

Total Equity

As at December 31, 2021, the decrease in total equity of $843 million was mainly due to the total comprehensive loss of $610 million, distributions to non-controlling interests of $156 million and dividends declared on common and preferred shares of $90 million, partially offset by the effect of shared-based payment plans of $13 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 2021, Moody's reaffirmed its Corporate Family Rating of Ba1 and maintained its rating outlook at stable. During 2021, DBRS Limited confirmed 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 trends. During 2021, S&P Global Ratings reaffirmed the Company's Issuer Credit Rating and Senior Unsecured Debt 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

A strong financial position provides the Company with better access to capital markets through commodity and credit cycles. We use total capital to help evaluate the strength of our financial position.

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

As at Dec. 31	2021		2020		2019	
	$	%	$	%	$	%
TransAlta Corporation						
Net senior unsecured debt						
Recourse debt — CAD debentures	**251**	**4**	249	3	647	9
Recourse debt —US senior notes	**888**	**16**	886	13	905	13
Credit facilities	**—**	**—**	114	2	—	—
Other	**4**	**—**	7	—	9	—
Less: cash and cash equivalents	**(703)**	**(12)**	(121)	(2)	(348)	(5)
Less: other cash and liquid assets(1)	**(19)**	—	(13)	—	(17)	—
Net senior unsecured debt	**421**	**8**	1,122	16	1,196	17
Other debt liabilities						
Exchangeable debentures	**335**	**6**	330	5	326	5
Non-recourse debt						
TAPC Holdings LP bond	**102**	**2**	111	2	119	2
TransAlta OCP bond	**263**	**5**	284	4	305	4
Other	**—**	**—**	—	—	2	—
Lease liabilities	**78**	**1**	112	2	119	2
Total net debt — TransAlta Corporation	**1,199**	**22**	1,959	29	2,067	30
TransAlta Renewables						
Net TransAlta Renewables reported debt						
Credit facility	**—**	**—**	—	—	220	3
Non-recourse debt				—		
Pingston bond	**45**	**1**	45	1	45	1
Melancthon Wolfe Wind bond	**235**	**4**	268	4	298	4
New Richmond Wind bond	**120**	**2**	127	2	134	2
Kent Hills Wind bond	**221**	**4**	230	3	241	3
Windrise Wind bond	**171**	**3**	—	—	—	
Lease liabilities	**22**	**—**	22	—	23	—
Less: cash and cash equivalents	**(244)**	**(4)**	(582)	(9)	(63)	(1)
Debt on TransAlta Renewables Economic Investments						
US tax equity financing(2)	**135**	**2**	134	2	145	2
South Hedland non-recourse debt(3)	**732**	**13**	772	11	—	—
Total net debt — TransAlta Renewables	**1,437**	**25**	1,016	14	1,043	14
Total consolidated net debt(4)(5)	**2,636**	**47**	2,975	43	3,110	44
Non-controlling interests	**1,011**	**18**	1,084	16	1,101	15
Exchangeable preferred securities(5)	**400**	**7**	400	6	—	—
Equity attributable to shareholders						
Common shares	**2,901**	**51**	2,896	43	2,978	42
Preferred shares	**942**	**17**	942	14	942	13
Contributed surplus, deficit and accumulated other comprehensive income	**(2,261)**	**(40)**	(1,486)	(22)	(959)	(14)
Total capital	**5,629**	**100**	6,811	100	7,172	100

(1) Includes principal portion of TransAlta OCP restricted cash and fair value asset of hedging instruments on debt.
(2) TransAlta Renewables has an economic interest in the entities holding these debts.
(3) TransAlta Renewables has an economic interest in the Australia entities holding these debts.
(4) The tax equity financing for Skookumchuck, an equity accounted joint venture, is not represented in these amounts.
(5) In 2021, total consolidated net debt excludes the exchangeable preferred securities as they are considered equity with dividend payments for credit purposes. In 2020, 50 per cent of the exchangeable preferred securities were classified as debt and included in total consolidated net debt. 2020 has been revised to be consistent with the change in 2021. For accounting purposes, they are accounted for as debt with interest expense in the consolidated financial statements.

Total capital consists of long-term debt, exchangeable securities and equity, less:
- Available cash and cash equivalents, as capital is managed internally and evaluated by management using a net debt position. In this regard, these funds may be available and used to facilitate repayment of debt;
- The principal portion of restricted cash on TransAlta OCP bonds because this cash is restricted specifically to repay outstanding debt; and
- The fair value of economic and designated hedging instruments on debt in an asset or liability, as the carrying value of the related debt is impacted by changes in foreign exchange rates.

We continued strengthening our financial position during 2021 and have sufficient liquidity to fund our growth strategy. We have enhanced shareholder value through the following:

2021
- Obtained $173 million in project financing related to our Windrise wind facility.

2020
- Obtained AU$800 million in project financing related to our South Hedland facility;
- On Oct. 30, 2020, we received the second tranche of $400 million from Brookfield in consideration for redeemable, retractable first preferred shares;
- Redeemed our outstanding 5 per cent $400 million medium-term notes due on Nov. 25, 2020; and
- Purchased and cancelled 7,352,600 common shares at an average price of $8.33 per share through our NCIB program, for a total cost of $61 million.

2019
- Obtained US$126 million in tax equity financing to fund the Big Level and Antrim wind facilities;
- Entered into a strategic investment with Brookfield whereby Brookfield agreed to invest $750 million in the Company. On May 1, 2019, we received the initial tranche of $350 million in exchange for seven per cent unsecured subordinated debentures due May 1, 2039, which are exchangeable by Brookfield into an equity ownership interest in our Alberta Hydro Assets in the future; and
- Purchased and cancelled 7,716,300 common shares at an average price of $8.80 per share through our NCIB program, for a total cost of $68 million.

Between 2022 and 2024, we have $1,104 million of debt maturing, including $515 million of recourse debt, with the balance mainly related to scheduled non-recourse debt repayments. We currently expect to refinance the senior notes maturing in 2022.

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

		Utilized			
As at Dec. 31, 2021	**Facility size**	**Outstanding letters of credit[1]**	**Actual drawings**	**Available capacity**	**Maturity date**
TransAlta Corporation					
Committed syndicated bank facility[2]	1,250	618	—	632	Q2 2025
Canadian committed bilateral credit facilities	240	186	—	54	Q2 2023
TransAlta Renewables					
Committed credit facility[2]	700	98	—	602	Q2 2025
Total	**2,190**	**902**	**—**	**1,288**	

(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. At Dec. 31, 2021, we provided cash collateral of $55 million.
(2) TransAlta has letters of credit of $157 million and TransAlta Renewables has letters of credit of $98 million issued from uncommitted demand facilities; these obligations are backstopped and reduce the available capacity on the committed credit facilities.

The US dollar relative to the Canadian dollar weakened from Dec. 31, 2020 to Dec. 31, 2021, with no impact on our long-term debt balances as at Dec. 31, 2021. The weakening of the US dollar decreased our long-term debt balances as at Dec. 31, 2020 by $24 million. Almost all our US-denominated debt is hedged either through financial contracts or net investments in our US operations.

US Tax Equity Financing

The Company owns equity interests in some facilities that are eligible for tax incentives available for renewable energy facilities in the United States. With its current portfolio of renewable energy facilities, TransAlta cannot fully monetize such tax incentives. To take full advantage of these incentives, the Company partners with Tax Equity Investors ("TEI") who invest in these facilities in exchange for a share of the tax credits.

Some TEI financing structures include a partial pay as you go ("Pay-go") funding arrangement under which, when the actual annual MWh production exceeds a certain production threshold, the TEI are obligated to make a cash contribution ("Pay-go Contribution") to the Company. The Pay-go arrangement results in a lower initial investment by the TEI and provides them with some protection from potential underperformance of the asset.

TransAlta recognizes the TEI contributions as long-term debt, at an amount representing the proceeds received from the TEI in exchange for shares of a subsidiary of TransAlta, net of the following elements:

- Production tax credits ("PTC")— Allocation of PTCs to the TEI derived from the power generated during the period is recognized in other revenues as earned and as a reduction in tax equity financing;
- Tax shield — Allocation of tax benefits and attributes to the TEI, such as investment tax credits and tax depreciation, is recognized in net interest expense as claimed and as a reduction in tax equity financing;
- Interest expense — Interest expense using the effective interest rate method is recognized in net interest expense as incurred and as an increase in tax equity financing;
- Pay-go contributions — Additional cash contributions made by the TEI when the annual production exceeds the contractually determined threshold and is recognized as an increase in tax equity financing; and
- Cash distributions — Cash payments to the TEI, recognized as a reduction in tax equity financing.

Production Tax Credit Program

Current United States tax law allows qualified wind energy projects to receive tax credits that are earned for each MWh of generation during the first 10 years of the projects' operation. The TEIs are allocated a portion of the renewable energy facility's taxable income (losses) and PTCs produced and a portion of the cash generated by the facility until they achieve an agreed-upon after-tax investment return ("Flip Point"). After the Flip Point, the TEI will retain a lesser portion of the cash and the taxable income (losses) generated by the facility.

Facility	Commercial operation date	Expected Flip Point	Initial TEI investment ($)	Expected annual PTC generation ($)	Expected annual Pay-go Contribution ($)	TEI allocation of taxable income and PTCs (pre-Flip Point)	TEI allocation of cash distributions (pre-Flip Point) ($)
Lakeswind	2014	2029	45	4	—	99 %	22
Big Level and Antrim	2019	2030	126	9	—	99 %	58
Skookumchuck(1)	2020	2029 - 2030	121	10	—	99 %	29

(1) 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.

Non-Recourse Debt

The Melancthon Wolfe Wind LP, Pingston, TAPC Holdings LP, New Richmond Wind LP, Kent Hills Wind LP, TEC Hedland Pty Ltd notes, Windrise Wind LP and TransAlta OCP LP non-recourse bonds with a carrying value of $1.9 billion (Dec. 31, 2020 — $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 2021, except the Kent Hills non-recourse bond as discussed below. However, 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 2022. At Dec. 31, 2021, $67 million (Dec. 31, 2020 — $73 million) of cash was subject to these financial restrictions. 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.

In connection with the foundation issues at Kent Hills 1 and 2 wind facilities, Kent Hills Wind LP has provided notice to the Trustee, BNY Trust Company of Canada, for the approximately $221 million outstanding non-recourse KH Bonds secured by, among other things, the Kent Hills 1, 2 and 3 wind facilities, that events of default may have occurred under the trust indenture governing the terms of such bonds. The Company is in discussions with the Trustee and holders of the KH Bonds to negotiate waivers and amendments. Refer to the Significant and Subsequent Events section of this MD&A for further details on the Kent Hills 1 and 2 wind facilities outage.

Returns to Providers of Capital

Net Interest Expense

The components of net interest expense are shown below:

Year ended Dec. 31	2021	2020	2019
Interest on debt	**163**	158	161
Interest on exchangeable debentures	**29**	29	20
Interest on exchangeable preferred shares	**28**	5	—
Interest income	**(11)**	(10)	(13)
Capitalized interest	**(14)**	(8)	(6)
Interest on lease liabilities	**7**	8	4
Credit facility fees, bank charges and other interest	**18**	18	15
Tax shield on tax equity financing(1)	**(9)**	1	(35)
Interest on the line loss proceeding	**—**	5	—
Other(2)	**2**	2	10
Accretion of provisions	**32**	30	23
Net interest expense	**245**	238	179

(1) Credit in 2021 primarily relates to the tax benefit associated with investment tax credits claimed in 2021 on the North Carolina Solar facility that was assigned to the tax equity investor. Credit in 2019 primarily relates to the tax benefit associated with bonus tax depreciation claimed in 2019 on the Big Level and Antrim wind facilities that was assigned to the tax equity investor. The tax equity investment is treated as debt under IFRS and the monetization of the tax depreciation and investment tax credits (as applicable) is considered a non-cash reduction of the debt balance and is reflected as a reduction in interest expense.
(2) In 2021, other interest expense included approximately nil (2020 — nil; 2019 — $5 million) for the significant financing component required under IFRS 15.

Net interest expense was higher in 2021 primarily due to the full year of interest incurred on the exchangeable preferred shares issued in the fourth quarter of 2020, project financing related to the South Hedland non-recourse debt obtained in the fourth quarter of 2020 and additional project financing related to the Windrise wind facility obtained in the fourth quarter of 2021, partially offset by an increase in capitalized interest on the construction of development projects, the redemption of the $400 million medium-term notes in the fourth quarter of 2020 and lower interest on other debt balances due to scheduled repayments and investment tax credits related to the North Carolina Solar facility tax equity.

Net interest expense was higher in 2020 primarily due to interest on the additional $400 million exchangeable preferred shares issued as part of the Brookfield Investment Agreement and the AU$800 million TEC Offering, both issued in October 2020. In addition, interest was higher due to interest charges received in 2020 for the AESO transmission line loss proceedings, and the 2019 impact of the $35 million tax credit received relating to the tax shield on Big Level and Antrim wind facilities offset by the termination of the Keephills 3 contract liability in 2019, resulting in the deferred financing costs being recognized.

Share Capital

On March 18, 2021, the Company announced that 1,417,338 of its 10.2 million Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares ("Series A Shares") and 871,871 of its 1.8 million Series B Cumulative Redeemable Floating Rate Preferred Shares ("Series B Shares") were tendered for conversion, on a one-for-one basis, into Series B Shares and Series A Shares, respectively, after having taken into account all election notices. As a result of the conversion, the Company had 9.6 million Series A Shares and 2.4 million Series B Shares issued and outstanding at March 31, 2021.

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

As at	Feb. 23, 2022	Dec. 31, 2021	Dec. 31, 2020
	Number of shares *(millions)*		
Common shares issued and outstanding, end of period	**271.2**	**271.0**	269.8
Preferred shares			
Series A	9.6	9.6	10.2
Series B	2.4	2.4	1.8
Series C	11.0	11.0	11.0
Series E	9.0	9.0	9.0
Series G	6.6	6.6	6.6
Preferred shares issued and outstanding in equity, end of period	**38.6**	**38.6**	38.6
Series I - Exchangeable Securities(1)	**0.4**	**0.4**	0.4
Preferred shares issued and outstanding, end of period	**39.0**	**39.0**	39.0

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

Dividends to Shareholders

The declaration of dividends is at the discretion of the Board. The following are the common and preferred shares dividends declared each quarter during 2021:

	Payable date		Common dividends	Preferred Series dividends per share				
Declaration date	**Common shares**	**Preferred shares**	**per share**	**A**	**B**	**C**	**E**	**G**
May 3, 2021	Jul 1, 2021	Jun 30, 2021	0.0450	0.17981	0.13108	0.25169	0.32463	0.31175
Aug 5, 2021	Oct.1, 2021	Sept. 30, 2021	0.0450	0.17981	0.13479	0.25169	0.32463	0.31175
Nov 1, 2021	Jan 1, 2022	Dec. 31. 2021	0.0500	0.17981	0.13970	0.25169	0.32463	0.31175
Dec 31, 2021	Apr 1, 2022	Mar 31, 2022	0.0500	0.17981	0.13309	0.25169	0.32463	0.31175

Non-Controlling Interests

As of Dec. 31, 2021, the Company owns 60.1 per cent (2020 — 60.1 per cent) of TransAlta Renewables.

In 2020, our ownership per cent (60.1 per cent) decreased from our ownership in 2019 (60.4 per cent) due to TransAlta Renewables issuing approximately one million common shares under their Dividend Reinvestment Plan ("DRIP"). We did not participate in this plan. In the fourth quarter of 2020, TransAlta Renewables suspended the DRIP in respect of any future declared dividends. The dividend paid on Oct. 30, 2020, to shareholders of record on Oct. 15, 2020, was the last dividend payment eligible for reinvestment by participating shareholders. Subsequent dividends will be paid only in cash.

TransAlta Renewables is a publicly traded company whose common shares are listed on the TSX under the symbol "RNW." TransAlta Renewables holds a diversified, highly contracted portfolio of assets with comparatively lower carbon intensity.

We also own 50.01 per cent of TA Cogen, which owns, operates or has an interest in three natural-gas-fired facilities (Ottawa, Windsor and Fort Saskatchewan) and one dual-fuel generating facility (Sheerness) for 2021 which will operate as a natural-gas-fired facility in 2022. Since we own a controlling interest in TA Cogen and TransAlta Renewables, we consolidate the entire earnings, assets and liabilities in relation to those assets.

Reported earnings attributable to non-controlling interests for the year ended Dec. 31, 2021, increased by $78 million to $112 million compared to 2020. Earnings increased at TransAlta Renewables in 2021 mainly due to higher finance income from investments in subsidiaries of TransAlta and no fair value losses recognized in the current year, partially offset by liquidating damages provisions related to unplanned outages at Sarnia cogeneration facility, unfavourable steam reconciliation adjustment to Canadian Gas, lower wind production from the Canadian wind fleet, lower foreign exchange gains and higher asset impairments. Earnings from TA Cogen were higher in 2021 mainly due to higher prices in the Alberta market. Refer to Note 13 of the consolidated financial statements for further details.

Reported earnings attributable to non-controlling interests for the year ended Dec. 31, 2020, decreased by $60 million to $34 million compared to 2019. Earnings were down at TransAlta Renewables in 2020 mainly due to lower finance income and change in the fair value of financial assets and an increase in income tax expense, offset by higher operating income and an increase in foreign exchange gains resulting from the strengthening of the Australian dollar relative to the Canadian dollar. Earnings from TA Cogen were lower in 2020 mainly due to lower operating income as a result of the planned outage for the dual-fuel conversion at Sheerness Unit 2, low Alberta market demand and the onerous contract provision for the coal supply agreement.

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.

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, 2021, we provided letters of credit totalling $902 million (2020 — $621 million) and cash collateral of $55 million (2020 — $49 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 obligation and other long-term liabilities, and decommissioning and other provisions. The increase in the amount of letters of credit issued during 2021 relates to the increased energy marketing activity, including the full requirements business, as well as pension plan commitments and the Highvale mine pension plan and reclamation obligations.

Commitments

Contractual commitments are as follows:

	2022	2023	2024	2025	2026	2027 and thereafter	Total
Natural gas, transportation and other contracts	47	54	45	44	45	508	**743**
Transmission	9	9	6	6	2	—	**32**
Coal supply and mining agreements	76	98	90	75	—	—	**339**
Long-term service agreements	89	46	43	32	25	54	**289**
Operating leases(1)	4	3	3	1	1	31	**43**
Long-term debt(2)	836	155	113	127	127	1,840	**3,198**
Exchangeable securities(3)	—	—	—	750	—	—	**750**
Principal payments on lease liabilities(4)	(6)	4	3	3	3	93	**100**
Interest on long-term debt and lease liabilities(5,6)	149	120	115	109	104	787	**1,384**
Interest on exchangeable securities(3,6)	53	53	62	—	—	—	**168**
Growth(7)	941	276	—	—	—	—	**1,217**
TransAlta Energy Transition Bill	6	6	—	—	—	—	**12**
Total	**2,204**	**824**	**480**	**1,147**	**307**	**3,313**	**8,275**

(1) Includes leases that have not yet commenced.
(2) Excludes impact of hedge accounting and derivatives.
(3) Assumes the exchangeable securities will be exchanged by Brookfield on Jan. 1, 2025. Please refer to the Significant and Subsequent Events section of this MD&A for further details.
(4) Lease liabilities include a lease incentive of $13 million, expected to be received in 2022.
(5) Interest on long-term debt is based on debt currently in place with no assumption as to refinancing on maturity.
(6) Not recognized as a financial liability on the Consolidated Statements of Financial Position.
(7) For further details on growth commitments, refer to the Accelerated Clean Electricity Growth Plan section of this MD&A.

Contingencies

Transmission Line Loss Rule Proceeding

The Company has been participating in a line loss rule proceeding before the AUC. The AUC determined that it has the ability to retroactively adjust line loss charges going back to 2006 and directed the AESO to recalculate loss factors for 2006 to 2016. The AUC approved an invoice settlement process and all three planned settlements have been received. The first two invoices were settled by the first quarter of 2021 and the third invoice settled in the second quarter of 2021. The true-up invoices issued by the AESO in the fourth quarter of 2021 were settled by Dec. 31, 2021, with no further invoices expected.

FMG Dispute at South Hedland Power Station

On May 2, 2021, the Company entered into a conditional settlement with FMG. The settlement was concluded and the actions were formally dismissed in the Supreme Court of Western Australia on Dec. 7, 2021. The settlement amount has been recorded as revenue in the fourth quarter of 2021, while all other balances previously provided for have been reversed. The settlement has resulted in FMG continuing as a customer of the South Hedland facility.

Mangrove Claim

On April 23, 2019, Mangrove commenced an action in the Ontario Superior Court of Justice naming the Company, the incumbent members of the Board of the Company on such date, and Brookfield as defendants. Mangrove was seeking to set aside the 2019 Brookfield transaction. The parties reached a confidential settlement and the action was discontinued in the Ontario Superior Court of Justice on April 30, 2021.

Keephills 1 Stator Force Majeure Appeal

The Balancing Pool and ENMAX are seeking to set aside an arbitration award on the basis that they did not receive a fair hearing. The Alberta Court of Queen's Bench ("ABQB") dismissed the Balancing Pool and ENMAX's allegations of unfairness on June 26, 2019. The Balancing Pool and ENMAX, however, sought leave to appeal the ABQB's decision at the Court of Appeal, which was granted on Feb. 13, 2020. The appeal was heard on July 8, 2021. After the hearing, counsel for ENMAX raised concerns that one of the three justices on the appeal panel was distracted during the hearing. The justice has since recused herself from the hearing and the parties made submissions with respect to whether the remaining two justices can continue to issue the decision or whether a new hearing is required. On Nov. 8, 2021, the Alberta Court of Appeal released its decision and ordered that the appeal be re-heard by a new three-person panel of the Court of Appeal, which was heard on Jan. 27, 2022. TransAlta remains of the view that the Court of Appeal will affirm the ABQB decision that the arbitration proceeding was fair.

Keephills 1 Superheater Force Majeure

Keephills Unit 1 was taken offline from March 17, 2015 to May 17, 2015, as a result of a large leak in the secondary superheater. TransAlta claimed force majeure under the Alberta PPA. ENMAX, the purchaser under the Alberta PPA at the time, did not dispute the force majeure but the Balancing Pool attempted to do so, seeking to recover $12 million in capacity payment charges it paid to TransAlta while the unit was offline. The parties reached a confidential settlement on April 21, 2021, and this matter is now resolved.

Sundance A Decommissioning

TransAlta filed an application with the AUC 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. Due to various factors, including the COVID-19 pandemic and significant information requests from the Balancing Pool, the application has been delayed. While a hearing date has not been set, the application will likely be heard in late 2022 or early 2023. TransAlta expects to receive payment from the Balancing Pool for its decommissioning costs; however, the amount that the AUC will award is uncertain.

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

The Balancing Pool claims to be entitled to emission performance credits ("EPCs") earned by the Hydro facilities as a result of opting those facilities into the *Carbon Competitiveness Incentive Regulation* from 2018-2020 inclusive. The Balancing Pool claims ownership of the EPCs because it believes the change-in-law provisions under the Hydro PPA require the EPCs to be passed through to the Balancing Pool. TransAlta has not received any benefit from the EPCs or from any purported change in law and believes that the Balancing Pool has no rights to these credits. An arbitration has commenced, and the hearing is scheduled for Feb. 6-10, 2023.

Direct Assigned Capital Deferral Account ("DACDA") Application
AltaLink Management Ltd. ("AltaLink") and TransAlta (as a secondary applicant) filed an application before the AUC to recover its 2016-2018 DACDA costs incurred for the 240 kV line upgrades for the Edmonton Region Project. The AUC disallowed 15 per cent (approximately $3 million) of TransAlta's portion. TransAlta disputed this finding and filed a permission to appeal application with the Court of Appeal and a review and variance application with the AUC (the "R&V"). The AUC dismissed the R&V application on April 22, 2021. The permission to appeal was subsequently discontinued on July 5, 2021, which concludes this matter.

Sarnia Outages
The Sarnia cogeneration facility experienced three separate outages between May 19, 2021 and June 9, 2021 that resulted in steam interruptions to its industrial customers. As a result, the customers have submitted claims for liquidated damages. Steam supply disruptions of this nature are atypical and infrequent at the Sarnia cogeneration facility. The Company conducted an investigation to determine the root cause of each of the three events, which concluded that all three events do not qualify as events of force majeure. As such, liquidated damages in an amount dictated by the applicable agreements are payable by TransAlta to the customers for the three outages and have been accrued within contract liabilities.

Kaybob 3 Cogeneration Dispute
The Company is engaged in a dispute with Energy Transfer Canada ULC, formerly SemCAMS Midstream ULC ("ET Canada") as a result of ET Canada's purported termination of agreements between the parties to develop, construct and operate a 40 MW cogeneration facility at the Kaybob South No. 3 sour gas processing facility. TransAlta commenced an arbitration seeking full compensation for ET Canada's wrongful termination of the agreements. ET Canada seeks a declaration that the agreements were lawfully terminated. A hearing is scheduled for two weeks starting Jan. 9, 2023.

Cash Flows
The following chart highlights significant changes in the consolidated statements of cash flows for the years ended Dec. 31, 2021, Dec. 31, 2020 and Dec. 31, 2019:

Year ended Dec. 31	2021	2020	Increase/ (decrease)
Cash and cash equivalents, beginning of year	**703**	411	292
Provided by (used in):			
Operating activities	**1,001**	702	299
Investing activities	**(472)**	(687)	215
Financing activities	**(282)**	272	(554)
Translation of foreign currency cash	**(3)**	5	(8)
Cash and cash equivalents, end of year	**947**	703	244

Cash provided by operating activities for the year ended Dec. 31, 2021, increased compared with 2020 primarily due to to higher revenues being realized in Alberta on the merchant assets, partially offset by higher fuel and purchased power and OM&A costs as the Company transitions off coal.

Cash used in investing activities for the year ended Dec. 31, 2021, decreased compared with 2020, largely due to:
- No acquisitions of investments in 2021 compared to Skookumchuck and EMG International LLC ("EMG") in 2020 ($102 million);
- Proceeds on the sale of Pioneer Pipeline ($128 million) and the sale of equipment within the Energy Transition segment ($39 million); and
- Higher cash spent on the North Carolina Solar facility acquisition ($120 million) in 2021 compared to the Ada acquisition of ($32 million) in 2020.

Cash used in financing activities for the year ended Dec. 31, 2021, increased compared with 2020, largely due to:
- Lower debt issuances in 2021. Issuance of the Windrise Wind LP bond of $173 million in 2021 compared to $753 million in long-term debt from the TEC Offering and $400 million in exchangeable securities in 2020;
- Increased distributions paid to subsidiaries' non-controlling interests ($59 million);
- Partially offset by lower repayments on long term debt ($397 million); and
- Lower common share repurchases under the NCIB ($53 million).

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 ("own use") 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, while any ineffective portion is recognized in net earnings.

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 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 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. Foreign exchange forward contracts and cross-currency swaps may be used to offset the exposures resulting from foreign-denominated long-term debt. 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 earnings ("OCI"). These gains or losses are subsequently reclassified from OCI to net earnings in the same period as the hedged forecast cash flows impact net earnings, 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 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 in the period in which the change occurs.

Fair Values

The majority of fair values for our project, 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, 2021, Level III instruments had a net asset carrying value of $159 million (2020 — $582 million). Please refer to the Critical Accounting Policies and Estimates section of this MD&A for further details regarding valuation techniques. Our risk management profile and practices have not changed materially from Dec. 31, 2020.

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, 2021, 2020 and 2019. 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 audited annual 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, or as an alternative for, 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. See the Segmented Financial Performance and Operating Results, Segmented Financial Performance and Operating Results for the Fourth Quarter, 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

In the fourth quarter of 2021, comparable EBITDA was relabelled as adjusted EBITDA to align with industry standard terminology. Each business segment assumes responsibility for its operating results measured to adjusted EBITDA. Adjusted EBITDA is an important metric for management that represents our core business profitability. 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. Adjusted EBITDA is a non-IFRS measure. The following are descriptions of the adjustments made.

Adjustments to revenue

- Certain assets we own in Canada and in Australia are fully contracted and recorded as finance leases under IFRS. We believe 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 to fuel and purchased power

- We adjust for depreciation on our mining equipment included in fuel and purchased power.
- We adjust for items resulting from the decision in 2020 to accelerate being off-coal and accelerating the shutdown of the Highvale mine by the end of 2021 as not reflective of ongoing business performance. Within fuel and purchased power this included coal inventory write-downs.
- 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 operations, maintenance and administration

- We adjust for write-down of parts and material inventory related to the Highvale mine and coal operations at our natural gas converted facilities.
- We adjust for the curtailment gain related to the Highvale mine defined-benefit pension plan.

Adjustments to net other operating income (expense)

- We adjust for the onerous contract provision for future royalty payments recognized with the shutdown of the Highvale mine.
- We adjust for the Sheerness going off-coal which resulted in the remaining coal supply payments on the existing coal supply agreement being recognized as an onerous contract in the fourth quarter of 2020.

Adjustments to earnings in addition to interest, taxes, depreciation and amortization

- Asset impairment charges (reversals) are removed as these are accounting adjustments that impact depreciation and amortization and do not reflect 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 Skookumchuck 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'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 non-IFRS financial measure that is forward-looking, 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 from operations
- Includes FFO related to the Skookumchuk 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 reclassified to reflect cash from operations.
- We adjust for items included in cash from operations related to the decision in 2020 to accelerate being off-coal and accelerating the shutdown of the Highvale mine by the end of 2021, and the write-down on parts and material inventory for our coal operations ("Clean energy transition provisions and adjustments").

Free Cash Flow
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, FFO before interest to adjusted interest coverage and adjusted net debt to adjusted EBITDA are non-IFRS ratios that are presented in the MD&A. See 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 is a non-IFRS ratio.

Supplementary Financial Measures
Financial highlights presented on a proportional basis of TransAlta Renewables, deconsolidated adjusted EBITDA, deconsolidated FFO and deconsolidated adjusted EBITDA to deconsolidated FFO are supplementary financial measures the Company uses to present adjusted EBITDA on a deconsolidated basis. See the Financial Highlights on a Proportional Basis of TransAlta Renewables and Key Non-IFRS Financial Ratios sections of this MD&A for additional information.

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

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

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

	Attributable to common shareholders									
	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	84	98	172	238	26	(2)	616	(6)	—	610
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	3	82	(8)	(12)	—	65	—	(65)	—
Decrease in finance lease receivable	—	—	11	—	—	—	11	—	(11)	—
Finance lease income	—	—	6	—	—	—	6	—	(6)	—
Unrealized foreign exchange (gain) loss on commodity	—	—	—	—	—	—	—	—	—	—
Adjusted revenues	84	101	271	230	14	(2)	698	(6)	(82)	610
Fuel and purchased power	9	6	110	149	—	(2)	272	—	—	272
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Mine depreciation	—	—	—	(11)	—	—	(11)	—	11	—
Coal Inventory write-down	—	—	—	(1)	—	—	(1)	—	1	—
Adjusted fuel and purchased power	9	6	109	137	—	(2)	259	—	13	272
Carbon compliance	—	—	14	25	—	—	39	—	—	39
Gross margin	75	95	148	68	14	—	400	(6)	(95)	299
OM&A	7	17	46	20	5	29	124	—	—	124
Reclassifications and adjustments:										
Parts and materials write-down	—	—	—	3	—	—	3	—	(3)	—
Curtailment gain	—	—	—	6	—	—	6	—	(6)	—
Adjusted OM&A	7	17	46	29	5	29	133	—	(9)	124
Taxes, other than income taxes	1	2	2	1	—	—	6	—	—	6
Net other operating income	—	—	(10)	(8)	—	—	(18)	—	—	(18)
Reclassifications and adjustments:										
Royalty onerous contract and contract termination penalties	—	—	—	9	—	—	9	—	(9)	—
Adjusted net other operating income	—	—	(10)	1	—	—	(9)	—	(9)	(18)
Adjusted EBITDA	67	76	110	37	9	(29)	270			
Equity income										4
Finance income from subsidiaries										6
Depreciation and amortization										(134)
Asset impairment										(28)
Net interest expense										(59)
Foreign exchange loss										(6)
Gain on sale of assets and other										(2)
Loss before income taxes										(32)

(1) Skookumchuck has been included on a proportionate basis in the Wind and Solar segment. Includes reclassification adjustments.

The following table reflects Adjusted EBITDA by segment and provides reconciliation to earnings (loss) before income taxes for the three months ended Dec. 31, 2020:

	Attributable to common shareholders									
	Hydro	Wind & Solar[(1)]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity accounted investments[(1)]	Reclass adjustments	IFRS financials
Revenues	31	92	167	230	19	8	547	(3)	—	544
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	10	34	(10)	10	—	44	—	(44)	—
Decrease in finance lease receivable	—	—	6	—	—	—	6	—	(6)	—
Finance lease income	—	—	3	—	—	—	3	—	(3)	—
Unrealized foreign exchange (gain) loss on commodity	—	—	4	—	—	—	4	—	(4)	—
Adjusted revenues	31	102	214	220	29	8	604	(3)	(57)	544
Fuel and purchased power	(1)	11	98	166	—	8	282	—	—	282
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Mine depreciation	—	—	(40)	(18)	—	—	(58)	—	58	—
Coal inventory write-down	—	—	—	(15)	—	—	(15)	—	15	—
Adjusted fuel and purchased power	(1)	11	57	133	—	8	208	—	74	282
Carbon compliance	—	—	30	15	—	—	45	—	—	45
Gross margin	32	91	127	72	29	—	351	(3)	(131)	217
OM&A	9	13	42	27	6	21	118	—	—	118
Taxes, other than income taxes	1	1	2	3	—	1	8	—	—	8
Net other operating expense (income)	—	—	19	—	—	—	19	—	—	19
Reclassifications and adjustments:										
Impact of Sheerness going off-coal	—	—	(28)	—	—	—	(28)	—	28	—
Adjusted net other operating income	—	—	(9)	—	—	—	(9)	—	28	19
Adjusted EBITDA	22	77	92	42	23	(22)	234			
Equity income										1
Finance income from subsidiaries										4
Depreciation and amortization										(173)
Asset impairment										(17)
Net interest expense										(64)
Foreign exchange loss										2
Gain on sale of assets and other										7
Loss before income taxes										(168)

(1) Skookumchuck has been included on a proportionate basis in the Wind and Solar segment. Includes reclassification adjustments.

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 for the three months ended Dec. 31, 2021 and 2020:

Three months ended Dec. 31	2021	2020
Cash flow from operating activities[1]	54	110
Change in non-cash operating working capital balances	148	25
Cash flow from operations before changes in working capital	**202**	135
Adjustments		
Share of adjusted FFO from joint venture[1]	6	3
Decrease in finance lease receivable	11	6
Clean energy transition provisions and adjustments[2]	(6)	15
Other[3]	—	2
FFO[4]	**213**	161
Deduct:		
Sustaining capital[1]	(55)	(58)
Productivity capital	(2)	(3)
Dividends paid on preferred shares	(10)	(9)
Distributions paid to subsidiaries' non-controlling interests	(38)	(29)
Principal payments on lease liabilities[1]	(2)	(10)
FCF[4]	**106**	52
Weighted average number of common shares outstanding in the period	271	273
FFO per share[4]	**0.79**	0.59
FCF per share[4]	**0.39**	0.19

(1) Includes our share of amounts for Skookumchuck, an equity accounted joint venture.
(2) Includes write-down on parts and material inventory for our coal operations, write-down on coal inventory to net realizable value and amounts due to contractors for not proceeding with the Sundance Unit 5 repowering project.
(3) Other consists of production tax credits which is a reduction to tax equity debt.
(4) These items are not defined and have no standardized meaning under IFRS. Please 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, 2021 and 2020:

Three months ended Dec. 31	2021	2020
Adjusted EBITDA[1]	270	234
Provisions	(18)	(10)
Interest expense[2]	(51)	(56)
Current income tax expense[2]	3	5
Realized foreign exchange loss	(4)	(1)
Decommissioning and restoration costs settled[2]	(5)	(5)
Other non-cash items	18	(6)
FFO[3]	**213**	161
Deduct:		
Sustaining capital[2]	(55)	(58)
Productivity capital	(2)	(3)
Dividends paid on preferred shares	(10)	(9)
Distributions paid to subsidiaries' non-controlling interests	(38)	(29)
Principal payments on lease liabilities[2]	(2)	(10)
FCF[3]	**106**	52

(1) Adjusted EBITDA is defined in the Additional IFRS Measures and Non-IFRS Measures section and reconciled to earnings (loss) before income taxes above.
(2) Includes our share of amounts for Skookumchuck, an equity accounted joint venture.
(3) FFO and FCF are defined in the Additional IFRS Measures and Non-IFRS Measures section and reconciled to cash flow from operating activities above.

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

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

	Attributable to common shareholders									
	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	—
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	1,132	728	173	4	2,768	(18)	(29)	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 write-down	—	—	—	(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	640	236	173	—	1,747	(18)	(240)	1,489
OM&A	42	59	175	117	36	84	513	(2)	—	511
Reclassifications and adjustments:										
Parts and materials write-down	—	—	(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 expense (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	322	262	494	133	137	(85)	1,263			
Equity income from associate										9
Finance lease income										25
Depreciation and amortization										(529)
Asset impairment										(648)
Net interest expense										(245)
Foreign exchange gain										16
Gain on sale of assets and other										54
Loss before income taxes										(380)

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

Year ended Dec. 31, 2020	Attributable to common shareholders									
	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	152	332	787	704	122	7	2,104	(3)	—	2,101
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	2	33	(14)	21	—	42	—	(42)	—
Decrease in finance lease receivable	—	—	17	—	—	—	17	—	(17)	—
Finance lease income	—	—	7	—	—	—	7	—	(7)	—
Unrealized foreign exchange loss on commodity	—	—	4	—	—	—	4	—	(4)	—
Adjusted revenues	152	334	848	690	143	7	2,174	(3)	(70)	2,101
Fuel and purchased power	8	25	325	435	—	12	805	—	—	805
Reclassifications and adjustments:										
Australian interest income	—	—	(4)	—	—	—	(4)	—	4	—
Mine depreciation	—	—	(100)	(46)	—	—	(146)	—	146	—
Coal inventory write-down	—	—	—	(37)	—	—	(37)	—	37	—
Adjusted fuel and purchased power	8	25	221	352	—	12	618	—	187	805
Carbon compliance	—	—	120	48	—	(5)	163	—	—	163
Gross margin	144	309	507	290	143	—	1,393	(3)	(257)	1,133
OM&A	37	53	166	106	30	80	472	—	—	472
Taxes, other than income taxes	2	8	13	9	—	1	33	—	—	33
Net other operating expense (income)	—	—	(11)	—	—	—	(11)	—	—	(11)
Reclassifications and adjustments:										
Impact of Sheerness going off-coal	—	—	(28)	—	—	—	(28)	—	28	—
Adjusted net other operating income			(39)	—	—	—	(39)	—	28	(11)
Adjusted EBITDA	105	248	367	175	113	(81)	927			
Equity income from associate										1
Finance lease income										7
Depreciation and amortization										(654)
Asset impairment										(84)
Net interest expense										(238)
Foreign exchange loss										17
Gain on sale of assets and other										9
Loss before income taxes										(303)

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

Year ended Dec. 31, 2019	Attributable to common shareholders								
	Hydro	Wind & Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total	Reclass adjustments	IFRS financials
Revenues	156	312	851	905	129	(6)	2,347	—	2,347
Reclassifications and adjustments:									
Unrealized mark-to-market (gain) loss	—	(17)	6	(12)	(10)	—	(33)	33	—
Decrease in finance lease receivable	—	—	24	—	—	—	24	(24)	—
Finance lease income	—	—	6	—	—	—	6	(6)	—
Adjusted revenues	156	295	887	893	119	(6)	2,344	3	2,347
Fuel and purchased power	7	16	315	539	—	4	881	—	881
Reclassifications and adjustments:									
Australian interest income	—	—	(4)	—	—	—	(4)	4	—
Mine depreciation	—	—	(81)	(40)	—	—	(121)	121	—
Adjusted fuel and purchased power	7	16	230	499	—	4	756	125	881
Carbon compliance	—	—	138	77	—	(10)	205	—	205
Gross margin	149	279	519	317	119	—	1,383	(122)	1,261
OM&A	36	50	162	124	30	73	475	—	475
Taxes, other than income taxes	3	8	9	8	—	1	29	—	29
Net other operating expense (income)	—	(10)	(41)	—	—	2	(49)	—	(49)
Termination of Sundance B and C PPAs	—	—	(14)	(42)	—	—	(56)	—	(56)
Adjusted EBITDA	110	231	403	227	89	(76)	984		
Finance lease income									6
Depreciation and amortization									(590)
Asset impairment									(25)
Gain on termination of Keephills 3 coal rights contract									88
Net interest expense									(179)
Foreign exchange loss									(15)
Gain on sale of assets and other									46
Earnings before income taxes									193

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:

Year ended Dec. 31	2021	2020	2019
Cash flow from operating activities[(1)(2)]	**1,001**	702	849
Change in non-cash operating working capital balances	**(174)**	(89)	(121)
Cash flow from operations before changes in working capital	**827**	613	728
Adjustments			
Share of adjusted FFO from joint venture[(2)]	**13**	3	—
Decrease in finance lease receivable	**41**	17	24
Clean energy transition provisions and adjustments[(3)]	**79**	37	—
Other[(4)]	**11**	15	5
FFO[(5)]	**971**	685	757
Deduct:			
Sustaining capital[(2)]	**(199)**	(157)	(141)
Productivity capital	**(4)**	(4)	(9)
Dividends paid on preferred shares	**(39)**	(39)	(40)
Distributions paid to subsidiaries' non-controlling interests	**(159)**	(102)	(111)
Principal payments on lease liabilities[(2)]	**(8)**	(25)	(21)
FCF[(5)]	**562**	358	435
Weighted average number of common shares outstanding in the year	**271**	275	283
FFO per share[(5)]	**3.58**	2.49	2.67
FCF per share[(5)]	**2.07**	1.30	1.54

(1) 2019 includes the PPA Termination Payments. See the Significant and Subsequent Events section for further details.
(2) Includes our share of amounts for Skookumchuck, an equity accounted joint venture.
(3) Includes write-down on parts and material inventory for our coal operations, write-down on coal inventory to net realizable value, amounts due to contractors for not proceeding with the Sundance Unit 5 repowering project and impairment of a previously recognized deferred asset, as it is no longer likely that we will incur sufficient capital or operating expenditures to utilize the remaining credit.
(4) Other consists of production tax credits which is a reduction to tax equity debt.
(5) 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 bridges our adjusted EBITDA to our FFO and FCF:

Year ended Dec. 31	2021	2020	2019
Adjusted EBITDA[(1)(2)]	**1,263**	927	984
Provisions and other	**(43)**	7	13
Interest expense[(3)]	**(200)**	(192)	(174)
Current income tax expense[(3)]	**(55)**	(35)	(35)
Realized foreign exchange gain (loss)	**(2)**	8	(6)
Decommissioning and restoration costs settled[(3)]	**(18)**	(18)	(34)
Other cash and non-cash items[(4)]	**26**	(12)	9
FFO[(5)]	**971**	685	757
Deduct:			
Sustaining capital[(3)]	**(199)**	(157)	(141)
Productivity capital	**(4)**	(4)	(9)
Dividends paid on preferred shares	**(39)**	(39)	(40)
Distributions paid to subsidiaries' non-controlling interests	**(159)**	(102)	(111)
Principal payments on lease liabilities[(3)]	**(8)**	(25)	(21)
FCF[(5)]	**562**	358	435

(1) 2019 amounts include the PPA Termination Payments.
(2) Adjusted EBITDA is defined in the Additional IFRS Measures and Non-IFRS Measures section and reconciled to earnings (loss) before income taxes above.
(3) Includes our share of amounts for Skookumchuck, an equity accounted joint venture.
(4) Other consists of production tax credits which is a reduction to tax equity debt.
(5) FFO and FCF are defined in the Additional IFRS Measures and Non-IFRS Measures section and reconciled to cash flow from operating activities above.

For explanations for the current period, please refer to the Highlights section of this MD&A.

FCF decreased by $77 million in 2020 compared to 2019, primarily due to lower segmented cash flows for the Alberta Thermal facilities included in the Gas and Energy Transition segments and higher sustaining capital expenditures, partially offset by strong cash flows for the Centralia Unit in the Energy Transition segment and lower distributions paid to subsidiaries' non controlling interests. There were no PPA Termination Payments included in 2020.

Financial Highlights on a Proportional Basis of TransAlta Renewables

The proportionate financial information below reflects TransAlta's share of TransAlta Renewables relative to TransAlta's total consolidated figures. The financial highlights presented on a proportional basis of TransAlta Renewables are supplementary financial measures to reflect TransAlta Renewables' portion of the consolidated figures.

Consolidated Results for the year ended Dec. 31

The following table reflects the generation and summary financial information on a consolidated basis for the year ended Dec. 31:

	Actual generation (GWh)			Adjusted EBITDA			Earnings (loss) before income taxes		
	2021	2020	2019	**2021**	2020	2019	**2021**	2020	2019
TransAlta Renewables									
Hydro	**434**	429	393	**17**	21	18			
Wind and Solar[1]	**3,898**	4,042	3,355	**248**	256	238			
Gas[1]	**3,236**	2,919	3,089	**217**	205	202			
Corporate	**—**	—	—	**(19)**	(20)	(20)			
TransAlta Renewables before adjustments	**7,568**	7,390	6,837	**463**	462	438	**133**	188	232
Less: Proportion of TransAlta Renewables not owned by TransAlta Corporation	**(3,020)**	(2,938)	(2,694)	**(185)**	(182)	(173)	**(53)**	(74)	(91)
Portion of TransAlta Renewables owned by TransAlta Corporation	**4,548**	4,452	4,143	**278**	280	265	**80**	114	141
Add: TransAlta Corporation's owned assets excluding TransAlta Renewables									
Hydro	**1,502**	1,703	1,652	**305**	84	92			
Wind and Solar	**—**	27	—	**14**	(8)	(7)			
Gas	**7,329**	7,861	8,730	**277**	162	201			
Energy Transition	**5,706**	7,999	11,852	**133**	175	227			
Energy Marketing	**—**	—	—	**137**	113	89			
Corporate	**—**	—	—	**(66)**	(61)	(56)			
TransAlta Corporation with Proportionate Share of TransAlta Renewables	**19,085**	22,042	26,377	**1,078**	745	811	**(433)**	(377)	102
Non-controlling interests	**3,020**	2,938	2,694	**185**	182	173	**53**	74	91
TransAlta Consolidated	**22,105**	24,980	29,071	**1,263**	927	984	**(380)**	(303)	193

(1) Wind and Solar and Gas segments include those assets that TransAlta Renewables holds an economic interest in.

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. We maintained a strong and flexible financial position in 2021.

Funds from Operations before Interest to Adjusted Interest Coverage

For the year ended Dec. 31	2021	2020	2019
FFO[1]	971	685	757
Less: PPA Termination Payments	—	—	(56)
Add: Interest on debt, exchangeable securities and preferred shares and leases, net of interest income and capitalized interest[2]	202	182	166
FFO before interest	1,173	867	867
Interest on debt, exchangeable securities and leases, net of interest income[2][3]	188	185	172
Add: 50 per cent of dividends paid on preferred shares[3]	33	22	20
Adjusted interest	221	207	192
FFO before interest to adjusted interest coverage (times)	5.3	4.2	4.5

(1) See the Segmented Financial Performance and Operating Results section in this MD&A for reconciliation of cash flow from operating activities to FFO. See also the Additional IFRS Measures and Non-IFRS Measures section for further details.
(2) The interest on tax equity financing for Skookumchuck, an equity accounted joint venture, is not represented in the amounts.
(3) Exchangeable preferred shares are considered equity with dividend payments for credit purposes. For accounting purposes, they are accounted for as debt with interest expense in the Consolidated Financial Statements.

The FFO before interest to adjusted interest coverage ratio is used by management to assess our ability to pay interest on outstanding debts. Our target for FFO before interest to adjusted interest coverage is 4.0 to 5.0 times. While 2020 and 2019 are within our target range, the 2021 ratio exceeds the high end of our target, and increased compared to 2020, mainly due to higher FFO in 2021 compared to 2020.

Adjusted Net Debt to Adjusted EBITDA (Excluding PPA Termination Payments)

As at Dec. 31	2021	2020	2019
Period-end long-term debt[1]	3,267	3,361	3,212
Exchangeable securities	335	330	326
Less: Cash and cash equivalents	(947)	(703)	(411)
Add: 50 per cent of issued preferred shares and exchangeable preferred shares[2]	671	671	471
Other[3]	(19)	(13)	(17)
Adjusted net debt[4]	3,307	3,646	3,581
Adjusted EBITDA[5]	1,263	927	984
Less: PPA Termination Payments[5]	—	—	(56)
Adjusted EBITDA (excluding PPA Termination Payments)[5]	1,263	927	928
Adjusted net debt to adjusted EBITDA (excluding PPA Termination Payments) (times)	2.6	3.9	3.9

(1) Consists of current and long-term portion of debt, which includes lease liabilities and tax equity financing.
(2) 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 purpose of this ratio, we consider 50% of issued preferred shares, including these, as debt.
(3) Includes principal portion of TransAlta OCP restricted cash and fair value of hedging instruments on debt (included in risk management assets and/or liabilities on the Consolidated Statements of Financial statements).
(4) The tax equity financing for Skookumchuck, an equity accounted joint venture, is not represented in the amounts. 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. See the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.
(5) Last 12 months.

The Company's capital is managed internally and evaluated by management using a net debt position. Our current and long-term debt is adjusted for 50 per cent of the exchangeable preferred shares plus 50 per cent of outstanding preferred shares less available cash and cash equivalents, principal portion of TransAlta OCP restricted cash and including fair value assets of hedging instruments on debt, to provide a more readily comparable debt figure from period to period. We use the adjusted net debt to adjusted EBITDA ratio as a measurement of financial leverage and assess our ability to pay off debt. Our target for adjusted net debt to adjusted EBITDA (excluding PPA Termination Payments) is 3.0 to 3.5 times. Our adjusted net debt to adjusted EBITDA ratio for 2021 was better than the low end of our target, and improved compared to 2020, as a result of strong adjusted EBITDA, debt repayments and higher cash and cash equivalents.

Deconsolidated Adjusted EBITDA by Segment

We invest in our assets directly as well as with joint venture partners. Deconsolidated financial information is a supplementary financial measure, and is not intended to be presented in accordance with IFRS.

Adjusted EBITDA is a key metric for TransAlta and TransAlta Renewables and provides management and shareholders a representation of core business profitability. Deconsolidated adjusted EBITDA is used in key planning and credit metrics and segment results highlight the operating performance of assets held directly at TransAlta that are comparable from period to period.

A reconciliation of adjusted EBITDA to deconsolidated adjusted EBITDA by segment results is set out below:

	2021			2020			2019		
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Hydro	**322**	**17**		105	21		110	18	
Wind and Solar	**262**	**248**		248	256		231	238	
Gas	**494**	**217**		367	205		403	202	
Energy Transition	**133**	—		175	—		227	—	
Energy Marketing	**137**	**—**		113	—		89	—	
Corporate	**(85)**	**(19)**		(81)	(20)		(76)	(20)	
Adjusted EBITDA(1)	**1,263**	**463**	**800**	927	462	465	984	438	546
Less: TA Cogen adjusted EBITDA			**(133)**			(54)			(80)
Less: Termination of Sundance B and C PPAs(1)			**—**			—			(56)
Less: EBITDA from joint venture investments(2)			**—**			(3)			—
Add: Dividend from TransAlta Renewables(1)			**151**			151			151
Add: Dividend from TA Cogen(1)			**34**			17			37
Deconsolidated TransAlta adjusted EBITDA			**852**			576			598

(1) Last 12 months.
(2) Represents our share of amounts for Skookumchuck, an equity accounted joint venture.

Deconsolidated FFO

The Company has set capital allocation targets based on deconsolidated FFO available to shareholders. Deconsolidated financial information is a supplementary financial measure and is not defined and has no standardized meaning under IFRS, and may not be comparable to those used by other entities or by rating agencies. See also the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further details. Deconsolidated FFO for the years ended Dec. 31 is detailed below:

	2021			2020			2019		
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Cash flow from operating activities	**1,001**	**336**		702	267		849	331	
Change in non-cash operating working capital balances	**(174)**	**(13)**		(89)	31		(121)	23	
Cash flow from operations before changes in working capital	**827**	**323**		613	298		728	308	
Adjustments:									
Decrease in finance lease receivable	**41**	**—**		17	—		24	—	
Clean energy transition provisions and adjustments	**79**	**—**		37	—		—	—	
Share of FFO from joint venture(1)	**13**	**—**		3	—		—	—	
Finance income - economic interests	**—**	**(108)**		—	(69)		—	(76)	
FFO - economic interests(2)	**—**	**191**		—	180		—	153	
Other(3)	**11**	**—**		15	—		5	—	
FFO	**971**	**406**	**565**	685	409	276	757	385	372
Dividend from TransAlta Renewables			**151**			151			151
Distributions to TA Cogen's Partner			**(56)**			(17)			(37)
Less: Share of adjusted FFO from joint venture(1)			**—**			(3)			—
Less: PPA Termination Payments			**—**			—			(56)
Deconsolidated TransAlta FFO			**660**			407			430

(1) Represents our share of amounts for Skookumchuck, an equity accounted joint venture.
(2) FFO - economic interests calculated as Free Cash Flow economic interests plus sustaining capital expenditures economic interests plus/minus currency adjustment and in 2021 less distributions from equity accounted joint venture.
(3) Other consists of production tax credits, which is a reduction to tax equity debt and in 2021 less distributions from equity accounted joint venture.

Deconsolidated Net Debt to Deconsolidated Adjusted EBITDA

In addition to reviewing fully consolidated ratios and results, management reviews net debt to adjusted EBITDA on a deconsolidated basis to highlight TransAlta's financial flexibility, balance sheet strength and leverage. Deconsolidated financial information is a supplementary financial measure and is not defined under IFRS, and may not be comparable to those used by other entities or by rating agencies. See also the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further details.

As at Dec. 31	2021	2020	2019
Adjusted net debt(1)	**3,307**	3,646	3,581
Add: TransAlta Renewables cash and cash equivalents	**244**	582	63
Less: TransAlta Renewables long-term debt	**(814)**	(692)	(961)
Less: US tax equity financing and South Hedland debt(2)	**(867)**	(906)	(145)
Deconsolidated net debt	**1,870**	2,630	2,538
Deconsolidated adjusted EBITDA(3)	**852**	576	598
Deconsolidated net debt to deconsolidated adjusted EBITDA(4) (times)	**2.2**	4.6	4.2

(1) Refer to the Adjusted Net Debt to Adjusted EBITDA (Excluding PPA Termination Payments) calculation under the Key Non-IFRS Financial Ratios section of this MD&A for the reconciliation and composition of adjusted net debt.
(2) Relates to assets where TransAlta Renewables has economic interests.
(3) Refer to the Deconsolidated Adjusted EBITDA by Segment section of this MD&A for the reconciliation and composition of deconsolidated adjusted EBITDA.
(4) The non-IFRS ratio is not a standardized financial measure under IFRS and might not be comparable to similar financial measures disclosed by other issuers.

Our target for deconsolidated net debt to deconsolidated adjusted EBITDA is 2.5 to 3.0 times. Our deconsolidated net debt to deconsolidated adjusted EBITDA ratio decreased compared with 2020, due to lower deconsolidated net debt which was partially offset by higher deconsolidated adjusted EBITDA. Lower deconsolidated net debt is a result of scheduled repayments on corporate debt and an increase in cash balances.

2022 Financial Outlook

The following table outlines our expectation on key financial targets and related assumptions for 2022 and should be read in conjunction with the narrative discussion that follows and the Governance and Risk Management section of this MD&A:

Measure	2022 Target	2021 Actuals
Adjusted EBITDA(1)	$1,065 million - $1,185 million	$1,263 million
FCF(1)	$455 million - $555 million	$562 million
Dividend	$0.20 per share annualized	$0.20 per share annualized

(1) These items are not defined and have no standardized meaning under IFRS. Please 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.

Range of key power price assumptions

Market	2022 Assumption
Alberta Spot ($/MWh)	$80 - $90
Mid-C Spot (US$/MWh)	US$45 - US$55
AECO Gas Price ($/GJ)	$3.60

Other assumptions relevant to the 2022 financial outlook	
Sustaining capital	$150 million - $170 million
Energy Marketing gross margin	$95 million - $115 million

Alberta Hedging

Range of hedging assumptions	2022
Hedged production (GWh)	6,278
Hedge Price ($/MWh)	$75
Hedged gas volumes (GJ)	50 million
Hedge gas prices ($/GJ)	$2.75

Adjusted EBITDA is estimated to be between \$1.065 billion to \$1.185 billion. FCF is expected to be between \$455 million and \$555 million and excludes the impact of rehabilitation capital expenditures required at Kent Hills 1 and 2 wind facilities. The midpoint of the range represents a 5 per cent decrease from the midpoint of the 2021 outlook largely driven by lower expectations on Alberta power pricing, a return to normal performance from Energy Marketing, and a step-up in mine reclamation expenditures, partially offset by the contribution from new assets, settlements of non-recurring provisions in 2021 and lower expected sustaining capital.

The Company expects its outlook for 2022 to be impacted by a number of factors detailed further below.

Market Pricing

For 2022, we see continuing strong merchant pricing levels in Alberta and the Pacific Northwest though at lowered target ranges for both regions. Lower year-over-year pricing in Alberta is expected to be driven by fewer planned outages and the expected additions of new wind and solar supply, including TransAlta's new Windrise wind facility and Garden Plain wind facility, expected to achieve commercial operation in late 2022. Weather and demand are also major factors in actual settled prices. Lower year-over-year pricing in the Pacific Northwest will be impacted by natural gas prices and hydro generation resulting from actual weather and hydrology of the year. Ontario power prices for 2022 are expected to be higher than 2021 due to higher natural gas prices and additional nuclear refurbishment outages.

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 of and 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 Alberta assets are managed as a portfolio to maximize the overall value of generation and capacity from our hydro, wind and energy storage and thermal facilities. Financial hedging is a key component of cash flow certainty and the hedges are tied to the portfolio of assets rather than a single facility.

Kent Hills Wind Facilities Outage

It is expected that the outage at Kent Hills 1 and 2 wind facilities will continue and rehabilitation efforts for all of the foundations is expected to commence during the second quarter of 2022 with the aim of fully returning the wind facilities to service by the end of 2023. The outage is expected to result in foregone revenue of approximately \$3.4 million per month on an annualized basis so long as all 50 turbines at Kent Hills 1 and 2 wind facilities are offline, based on average historical wind production, with revenue expected to be earned as the wind turbines are returned to service.

Addition of Windrise and North Carolina Solar

On Nov. 5, 2021, TransAlta Renewables completed the acquisition of the economic interest in the fully contracted 122 MW North Carolina Solar portfolio, which is expected to generate an average annual EBITDA[6] of approximately US\$9 million.

On Dec. 2, 2021, TransAlta Renewables announced commercial operation of the Windrise wind facility in Alberta was achieved on Nov. 10, 2021. Windrise is expected to generate an average annual EBITDA[6] of approximately \$20 million to \$22 million.

Fuel and Compliance Costs

For the Gas fleet, coal consumption in Alberta is expected to be zero in 2022 given TransAlta has now retired or fully converted all its coal-fired facilities to gas. Increased gas consumption in the Gas fleet will drive lower GHG emissions and the combined effect will result in lower total fuel and GHG costs for a given volume of power production. This will be partially offset by an increased carbon tax in Alberta.

In the Pacific Northwest of the US, the coal mine adjacent to our Centralia thermal facility is in the reclamation stage. Fuel at Centralia has been purchased from external suppliers in the Powder River Basin and delivered by rail. In 2020, we amended our fuel and rail contract such that our rail freight costs fluctuate partly with power prices. The delivered fuel cost in 2022 is expected to be marginally higher than 2021 costs.

Most of the generation from gas turbine-based power facilities is sold under contracts with pass-through provisions for fuel. For gas generation with no pass-through provisions, we purchase natural gas from outside companies coincident with production, thereby minimizing our risk to changes in prices.

[6] *Average annual EBITDA is not defined and has no standardized meaning under IFRS, and is forward-looking. Please refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further discussion.*

We closely monitor the risks associated with changes in electricity and input fuel prices on our future operations and, where we consider it appropriate, use various physical and financial instruments to hedge our assets and operations from such price risks.

Energy Marketing

Adjusted EBITDA from our Energy Marketing segment is affected by prices and volatility in the market, overall strategies adopted and changes in regulation and legislation. Our outlook has been adjusted to reflect the exceptional performance achieved in 2021. We continuously monitor both the market and our exposure to maximize earnings while still maintaining an acceptable risk profile. Our 2022 objective for Energy Marketing is for the segment to contribute between $95 million to $115 million in gross margin for the year, which is consistent with normalized performance expectations.

Exposure to Fluctuations in Foreign Currencies

Our strategy is to minimize the impact of fluctuations in the Canadian dollar against the US dollar and Australian dollar by offsetting foreign-denominated assets with foreign-denominated liabilities and by entering into foreign exchange contracts. We also have foreign-denominated expenses, including interest charges, which largely offset our net foreign-denominated revenues.

Decommissioning and Restoration Costs

Decommissioning and restoration costs are expected to be higher in 2022 due to the closure of the Highvale coal mine and increased reclamation activity at Centralia due to deferral of certain activities impacted by COVID-19.

Sustaining Capital Expenditures

The Company expects sustaining capital to be in the range of $150 million to $170 million. The midpoint for the range represents a 25 per cent decrease from the midpoint of the 2021 outlook. This is driven by fewer planned maintenance outages at the thermal fleet in Alberta due to the completion of gas conversions that occurred in 2021, partially offset by increased sustaining capital expenditures at the Sarnia cogeneration facility for planned major maintenance, as well as increased dam safety and major maintenance across our Hydro fleet. The Kent Hills foundation rehabilitation capital expenditure has been segregated from our sustaining capital range due to the extraordinary and rare nature of this expenditure. The initial estimated range for the rehabilitation at Kent Hills is between $75 million to $100 million with approximately $40 million to $60 million estimated to be incurred in 2022.

Our estimate for total sustaining capital is as follows:

	Spent in 2020	Spent in 2021	Expected spend in 2022
Total sustaining capital	**157**	**199**	**150 - 170**

Liquidity and Capital Resources

We expect to maintain adequate available liquidity under our committed credit facilities. We currently have access to $2.2 billion in liquidity, including $947 million in cash. We expect to be well positioned to refinance the upcoming debt maturity in 2022. The funds required for committed growth, sustaining capital and productivity projects are not expected to be significantly impacted by the current economic environment. Please refer to the Description of Business and Financial Capital sections of this MD&A for further details.

Net Interest Expense

Interest expense for 2022 is expected to be higher than in 2021 largely due to higher levels of debt. The increase in debt is mainly due to the $173 million Windrise project financing that was completed in November 2021. In addition, changes in interest rates on variable debt, and in the value of the Canadian dollar relative to the US and Australian dollars can affect the amount of interest expense incurred.

Critical Accounting Policies and 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 an 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 our Audit, Finance and Risk Committee ("AFRC") 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 models described below.

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 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. Refer to Note 15(B)(I) from our audited annual 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, 2021, is an estimated total upside of $105 million (2020 — $68 million upside) and total downside of $220 million (2020 — $94 million) impact to the carrying value of the financial instruments. Fair values are stressed for volumes and prices. The amount of $22 million upside (2020 — $35 million upside) and $145 million downside (2020 — $59 million downside) in the stress values stems from a long-dated power sale contract in the Pacific Northwest that is designated as a cash flow hedge utilizing assumed power prices ranging from US$28 to US$51/MWh (Dec. 31, 2020 — US$24-US$32/MWh) for the period beyond the liquid period, while the remaining amounts account for the rest of the portfolio. The variable volumes are stressed up and down one standard deviation from 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.

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 $32 million (2020 — $33 million downside) potential impact to the carrying value of nil as at Dec. 31, 2021 (2020 — 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 CGU to which the asset belongs. The 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 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 60 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. 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 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 2021.

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. Please refer to the Financial Position section of this MD&A for further details.

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 purposes of the 2021, 2020 and 2019 annual goodwill impairment reviews, the Company determined the recoverable amounts of the CGUs by calculating the fair value less costs of disposal using discounted cash flow projections based on the Company's long-range forecasts for the period extending to the last planned asset retirement in 2072. The resulting fair value measurement is categorized within Level III of the fair value hierarchy.

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, production and trading volumes, margins, and fuel and operating costs.

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.

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.

Leases

In determining whether our 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 we are 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 us, 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.

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.

We estimate the undiscounted amount of cash flow required to settle the decommissioning and restoration provisions is approximately $1.6 billion, which will be incurred between 2022 and 2072. The majority of these costs will be incurred between 2025 and 2050.

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 1 Presentation of Financial Statements: Material Accounting Policies

Effective for the 2021 annual financial statements, the Company early adopted amendments to IAS 1 *Presentation of Financial Statements* in advance of its mandatory effective date of Jan. 1, 2023, which requires entities to disclose their material accounting policy information rather than their significant accounting policies. The Company has updated the accounting policies disclosed in Note 2 based on its assessment of the amended standard.

Amendments to IAS 16 Property, Plant and Equipment: Proceeds before Intended Use

Effective Jan. 1, 2021, the Company early adopted amendments to IAS 16 *Property, plant and equipment* ("IAS 16 Amendments") in advance of its mandatory effective date of Jan. 1, 2022. The Company adopted the IAS 16 Amendments retroactively. No cumulative effect of initially applying the guidance arose. The IAS 16 Amendments prohibit deducting from the cost of an item of property, plant and equipment any proceeds from selling items produced while bringing that asset to the location and condition necessary for it to be capable of operating in a manner intended by management. Instead, an entity recognizes the proceeds from selling such items, and the cost of producing those items, in profit or loss. No adjustments resulted from early adopting the amendments.

IFRS 7 Financial Instruments: Disclosures — Interest Rate Benchmark Reform

The transition of the London Interbank Offered Rates ("LIBOR") has begun with the cessation of the publication of one-week and two-month USD LIBOR occurring on Dec. 31, 2021. The remaining overnight, one-, three-, six-, and 12-month USD LIBOR will continue to be published until their cessation date on June 30, 2023. Existing financial instruments may continue to use USD LIBOR while they are published until they mature, however, new financial instruments will not be using USD LIBOR if entered into after Dec. 31, 2021. The IASB issued Interest Rate Benchmark Reform — Phase 2 in August 2020, which amends IFRS 9 *Financial Instruments*, IAS 39 *Financial instruments: Recognition and Measurement*, IFRS 7 *Financial Instruments: Disclosures* and IFRS 16 *Leases*. The amendments were effective Jan. 1, 2021, and were adopted by the Company on Jan. 1, 2021. There was no financial impact upon adoption.

The Company's credit facilities references USD LIBOR for US-dollar drawings and the Canadian Dollar Offered Rate for Canadian drawings, and includes appropriate fallback language to replace these benchmark rates if a benchmark transition event were to occur. For the year ended Dec. 31, 2021, there were no drawings under the credit facilities. The Company has interest rate swap agreements in place with a notional amount of US$150 million referencing three-month LIBOR, expected to settle in the third quarter of 2022.

Future Accounting Changes

Amendments to IAS 37 Provisions, Contingent Liabilities and Contingent Assets

On May 14, 2020, the IASB issued *Onerous Contracts — Cost of Fulfilling a Contract* and amendments to IAS 37 *Provisions, Contingent Liabilities and Contingent Assets* to specify which costs to include when assessing whether a contract will be loss-making. The amendments are effective for annual periods beginning on or after Jan. 1, 2022, and will be adopted by the Company in 2022. The amendments are effective for contracts for which an entity has not yet fulfilled all its obligations on or after the effective date. No financial impact is expected upon adoption.

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

On May 7, 2021, the IASB issued amendments to IAS 12 *Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction*. 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, with early application permitted. The Company's current position aligns with the amendment and no financial impact is therefore expected upon adoption on the effective date.

Amendments to IAS 1 Classification of Liabilities as Current or Non-Current

In January 2020, the IASB issued amendments to IAS 1 *Presentation of Financial Statements*, to provide a more general approach to the presentation of liabilities as current or non-current based on contractual arrangements in place at the reporting date. These amendments specify that the 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, provide that management's expectations are not a relevant consideration as to whether the Company will exercise its rights to defer settlement of a liability and clarify when a liability is considered settled.

The amendments are effective for annual periods beginning on or after Jan. 1, 2023, and are to be applied retrospectively. The Company has not yet determined the impact of these amendments on its consolidated financial statements.

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.

Environmental, Social and Governance ("ESG")

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 ED&I), we believe the focus will only strengthen our corporate strategy and support value creation into the future. Our pillars include:

1. **Clean, Reliable and Sustainable Electricity Production**
2. **Safe, Healthy, Diverse and Engaged Workplace**
3. **Positive Indigenous, Stakeholder and Customer Relationships**
4. **Progressive Environmental Stewardship**
5. **Technology and Innovation**

We have been reporting on sustainability since 1994. This year, we have structured the ESG section of this MD&A to help stakeholders better understand the most material issues affecting our ESG performance.

Reporting on Our Material Sustainability Factors

TransAlta's ESG 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. Content is structured using non-traditional capital (this includes natural, human, social and relationship, intellectual and manufactured capital) as per guidance from the International Integrated Reporting Framework.

Climate-related data to be disclosed is informed by climate change questionnaires from CDP (the global disclosure system for environmental impacts known formerly as Carbon Disclosure Project) and the Task Force on Climate-related Financial Disclosures ("TCFD") recommendations. In 2021, we conducted a climate-related scenario analysis that enhanced our alignment with both international sustainability frameworks. GHG emissions data for scopes 1 and 2 follow the accounting and reporting standards of the GHG Protocol. For further information on climate change management and the findings of our scenario analysis, please refer to the Decarbonizing Our Energy Mix section of this MD&A.

We adopt guidance from the Global Reporting Initiative and Sustainability Accounting Standards Board ("SASB") requirements for 'Electric Utilities and Power Generators'. We continue to monitor the development of sustainability disclosure standards to assess our future reporting, such as the International Sustainability Standards Board and the Taskforce on Nature-related Financial Disclosures.

The disclosure of our most relevant sustainability factors is guided by our sustainability materiality assessment. Our materiality assessment is developed through evaluation of key sector-specific research on material issues and supported by internal and external engagement on key sustainability issues. Our Enterprise Risk Management ("ERM") program is designed to help the organization focus its efforts on key enterprise risks, within the planning horizon, that could significantly impact the success of its strategy, including its sustainability objectives. We consider a sustainability factor as material if it could substantively affect our ability to create value. Our major environmental risk factors include climate change, weather, environmental disasters, exposure to the elements, environmental compliance risk and current and emerging environmental regulation. Our major social risk factors include Indigenous and stakeholder relationships, local communities, public health and safety, employee and contractor health and safety, employee retention, supply chain and cybersecurity. For further guidance on our risk factors, please refer to the Governance and Risk Management section of this MD&A.

Transforming Our Business Model to Become Carbon Neutral by 2050

At TransAlta, our mission is to provide safe, low-cost and reliable clean electricity to our customers. As a customer-centred clean energy 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 we are uniquely positioned as the world continues to electrify and adopt sustainability practices. For further information, please 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 in the sections below.

How is TransAlta's strategy contributing to energy transition?

"In our sector, there is a lot of agreement about what is required to achieve a low-carbon energy transition. First, we need to transition away from high-emitting coal generation. As of the end of 2021, TransAlta has completed this transition in Canada and we will retire our single remaining coal unit in the US at the end of 2025. Second, we need to significantly expand the supply of zero-emission renewable electricity. TransAlta already has a leading portfolio of renewable assets and our growth plan will see us expand our wind and solar business by 2 GW over the next five years. Finally, we need to achieve breakthroughs that allow us to harness intermittent renewables to provide reliable electricity for consumers. TransAlta's WindCharger facility was the first utility-scale battery project linked to a renewables facility in Alberta and our growth plan includes further investments in energy storage. The key elements of TransAlta's strategy are aligned with the energy transition underway in the global economy."

How does the company's strategy align with global climate efforts?

"We are very proud of our emissions track record to date. Our Company has achieved a 29 million tonne annual GHG emission reduction from 2005 levels. This reduction already exceeds the national 2030 emissions targets in Canada, the US and Australia where we operate. In that sense, we are already ahead of the ambitious national efforts in our home markets. That said, we recognize that decarbonizing the electricity sector is a key pillar of global climate efforts because electrification enables emission reductions in other sectors, such as transportation. This means we have to continually raise our level of ambition as we did last year by setting our carbon neutrality target for 2050 and we did this year by enhancing and accelerating our near-term reduction target.

"We are the first publicly traded Canadian energy company to commit to setting a science-based emissions target. This step is critical in ensuring that our actions are aligned with the steps required to achieve global climate goals. Further, we were pleased to join the Powering Past Coal Alliance during the 26th UN Climate Change Conference of the Parties ("COP26") in Glasgow. The Alliance is a group of governments and companies committed to achieving one of the key steps in the global energy transition."

TransAlta accelerated and strengthened its GHG emissions reduction target. Why did the Company choose to take that step?

"Our new target is a function of our new growth strategy. Simply put, by focusing on growing our contracted renewables assets we are growing our business and not our emissions. This type of growth, coupled with coal-to-gas conversions that cut emissions from our thermal assets, and efficient on-site cogeneration, creates an emissions pathway for our Company that delivers substantial reductions over the next five years. We believe it is important for the Company to publicly hold itself accountable for delivering these results and ensuring our investors, customers and stakeholders are aware of where we are going in this important effort."

How can TransAlta help customers to decarbonize?

"Most importantly, TransAlta helps our customers by reliably delivering and operating renewable and storage projects and on-site generation that meet their energy needs. Underneath that core commitment is a set of technologies and contracting options that we tailor to ensure customers receive the energy they require, and environmental outcomes aligned with their ESG commitments. In 2021, we were proud to announce a major wind project in Oklahoma which will provide electricity to a leading US-based company, a major wind project in Alberta to provide electricity to Pembina Pipelines as well as a smaller-scale solar and battery project with BHP in Australia. All are examples of a tailored approach designed to meet the unique needs of customers as they advance their own decarbonization goals. In the future, we see more demand for reliable zero-emission electricity and our growth strategy is designed to position the Company to deliver these projects effectively for new and existing partners in all of our markets."

2022+ Sustainability Targets

Our 2022 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. Goals and targets are established to improve our ESG performance and to manage current and emerging material sustainability issues, in support of the United Nations Sustainable Development Goals ("UN SDGs") and the Future-Fit Business Benchmark. TransAlta is committed to decarbonizing our energy generation and to accelerating clean energy growth. We believe we can make a greater positive impact on UN SDG 7 "Affordable and Clean Energy" and SDG 13 "Climate Action", while supporting several other SDGs.

In December 2021, TransAlta approved 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. We estimate that this is in line with limiting global warming to 1.5°C and, in December 2021, committed to setting a science-based emissions reduction target through the Science Based Targets initiative. In 2021, the Company established a Sustainability-Linked Loan that will align the cost of borrowing to TransAlta's GHG emission reductions and gender diversity targets. For further details on the Sustainability-Linked Loan, please refer to the Significant and Subsequent Events section of this MD&A. In 2021, the Company's indirect wholly owned subsidiary, Windrise Wind LP, secured green bond financing. This supports our goal to deliver on our customers' needs for clean electricity. Please refer to the TransAlta Renewables Acquisitions section of this MD&A for further details.

Targets are outlined below:

ESG Alignment: Environment

TransAlta Sustainability Goal	TransAlta Sustainability Target	Alignment with UN SDG Target or Future-Fit Business Benchmark
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."
Reduce operational waste	By 2022, reduce total waste generation by 80 per cent over a 2019 baseline	UN SDG Target 12.5: "By 2030, substantially reduce waste generation through prevention, reduction, recycling and reuse."
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"
Reduce GHG emissions	By 2026, achieve a 75 per cent reduction of scope 1 and 2 GHG emissions from a 2015 base year	UN SDG Target 13.2: "Integrate climate change measures into national policies, strategies and planning."
	By 2050, achieve carbon neutrality	

ESG Alignment: Social

TransAlta Sustainability Goal	TransAlta Sustainability Target	Alignment with UN SDG Target or Future-Fit Target
Reduce safety incidents	Achieve a Total Recordable Injury Frequency rate below 0.61	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."
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 to all TransAlta employees by the end of 2023	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

TransAlta Sustainability Goal	TransAlta Sustainability Target	Alignment with UN SDG Target or Future-Fit Target
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: Environment and Social

TransAlta Sustainability Goal	TransAlta Sustainability Target	Alignment with UN SDG Target or Future-Fit Target
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."

Our 2021 Sustainability Performance

In 2021, we achieved an environmental performance milestone in our journey to grow our clean electricity fleet with the completion of our coal-to-gas conversions in Canada. Overall, the converted units generate nearly 50 per cent fewer CO_2 emissions fuelled by natural gas compared to coal. The completed unit conversions and the end of production at the Highvale coal mine in Alberta also contributed to the goals of the Powering Past Coal Alliance, which TransAlta joined at COP26. Our social performance was highlighted by our positive contribution to support equal access to all levels of education for youth and Indigenous peoples through financial support and employment opportunities.

Performance against our 2021 sustainability targets is outlined below:

ESG Alignment: Environment

TransAlta Sustainability Goal	TransAlta Sustainability Target	Results	Comments
Reclaim land utilized for mining	By 2040, complete full reclamation of our Centralia coal mine in Washington State	*On track*	Reclamation work at our Centralia and Highvale mines has been executed progressively.
	By 2046, complete full reclamation of our Highvale coal mine in Alberta	*On track*	Our Highvale coal mine in Alberta retired on Dec. 31 2021, and reclamation has been executed progressively.
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	*On track*	In 2021, we reduced fleet-wide water consumption by 4 million m^3 or 11 per cent over 2020 levels.
Reduce operational waste	By 2022, reduce total waste generation by 80 per cent over a 2019 baseline	*On track*	In 2021, we reduced total waste generation by 620,000 tonnes equivalent or 55 per cent over 2020 levels.
Reduce air emissions	By 2026, achieve a 95 per cent reduction of SO_2 emissions and an 80 per cent reduction of NOx emissions below 2005 levels	*On track*	Since 2005, we have reduced SO_2 emissions by 90 per cent and NO_x emissions by 77 per cent. In 2021, we reduced SO_2 emissions by 42 per cent and NO_x emissions by 29 per cent over 2020 levels.
Reduce GHG emissions	By 2030, achieve company-wide GHG reductions of 60 per cent below 2015 levels, in line with a commitment to the UN SDGs and prevention of 2°C of global warming	*Achieved*	Since 2015, we have reduced GHG emissions by 61 per cent. In 2021, we reduced approximately 3.9 million tonnes of CO_2e or 24 per cent over 2020 levels.
	By 2050, achieve carbon neutrality	*On track*	Since 2015, we have reduced GHG emissions by 61 per cent. In 2021, we reduced approximately 3.9 million tonnes of CO_2e or 24 per cent over 2020 levels.

ESG Alignment: Social

TransAlta Sustainability Goal	TransAlta Sustainability Target	Results	Comments
Reduce safety incidents	Achieve a Total Recordable Injury Frequency rate below 0.61	*Not achieved*	TRIF performance year over year has remained relatively unchanged. In 2021, we achieved a TRIF of 0.82 compared to 0.81 in 2020. Our focus on safety culture transformation remains as we continue to work to meet and exceed our goal of 0.61 in the future.
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 in 2021 represented a total value of $375,000 and provided 14 bursaries through a partnership with Indspire; funded academic upgrading programs through the Southern Alberta Institute of Technology; and maintained communication on employment opportunities through various mediums to support different access options for Indigenous communities.
	Provide Indigenous cultural awareness training to all TransAlta employees by the end of 2023.	*On track*	In 2021, we committed to and began development of Indigenous Awareness training that will be provided to all Canadian, Australian and US employees by the end of 2023.

ESG Alignment: Governance

TransAlta Sustainability Goal	TransAlta Sustainability Target	Results	Comments
Strengthen gender equality	Achieve 50 per cent female representation on the Board by 2030	*On track*	As of Dec. 31, 2021, women made up 42 per cent of our total Board composition compared to 45 per cent in 2020, due to the retirement of one female Board member. In 2021, we achieved 50 per cent female representation on the Board, excluding the two nominees from Brookfield.
	Achieve at least 40 per cent female employment among all employees of the Company by 2030	*On track*	As of Dec. 31, 2021, women made up 24 per cent of all employees, an increase over 2020 levels (21 per cent).
	Maintain equal pay for women in equivalent roles as men	*Achieved*	Equal pay for women in the Company was maintained in 2021.
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*	In 2021, we conducted a climate-related scenario analysis that enhanced our alignment with TCFD and CDP (the global disclosure system for environmental impacts known formerly as Carbon Disclosure Project).

ESG Alignment: Environment and Social

TransAlta Sustainability Goal	TransAlta Sustainability Target	Results	Comments
Leading clean power company by 2025	No further coal generation by the end of 2025 with 100 per cent of our owned net generation capacity to be from clean electricity (renewables and gas)	*On track*	In 2021, Sundance Unit 5 was retired, and Keephills Unit 2, Keephills Unit 3 and Sundance Unit 6 were converted to natural gas. The Highvale coal mine was closed. Centralia Unit 1 retired on Dec. 31, 2020, and the remaining unit is set to retire on Dec. 31, 2025.
	Discontinue coal power generation in Canada by the end of 2021	*Achieved*	In 2021, our Sundance 5 facility was retired, and Keephills Unit 2, Keephills Unit 3 and Sundance 6 facilities were converted to natural gas. The Highvale coal mine was closed.
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	*Achieved*	In 2021, the Company purchased a 122 MW portfolio of operating solar facilities in North Carolina and started the construction of a 48 MW solar and battery storage system in Western Australia. We also entered into long-term PPAs for the off take of 100 MW from our Garden Plain wind project in Alberta and 100 per cent of our 300 MW White Rock East and White Rock West wind projects in Oklahoma.

Decarbonizing Our Energy Mix

ESG is more than simply 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 commitment began more than one hundred years ago when we built the first hydro assets in Alberta, which still operate today. In 2002, we acquired our first wind farm, in 2015, our first solar farm, and in 2020, our first battery storage facility. Today, we operate over 50 renewable facilities across Canada, the US and Australia.

Our climate-change-related reporting is guided by the TCFD. This framework helps inform discussion and provide context on how climate change affects our business.

The following are examples of how we have transitioned our business to manage climate change risk and opportunity, how we have demonstrated leadership through action on climate change-related issues and how we are positioned for climate resiliency.

- Today, we are proud to be one of the largest producers of wind power in Canada and the largest producer of hydro power in Alberta — we have grown our nameplate renewable energy capacity from approximately 900 MW in 2000 to over 2,800 MW in 2021.
- Our business demonstrates climate change resiliency by reducing GHG emissions – we have a target to reduce annual CO_2e emission by 75 per cent over 2015 levels by 2026. Since 2015, we have reduced our annual emissions by 19.7 million tonnes of CO_2e or 61 per cent, putting us on track to achieve our 2026 target.
- As a leader in North American renewable electricity, we are well-positioned to build renewable energy facilities and hybrid facilities to support customer decarbonization goals. Our strategy involves retiring our single coal unit by the end of 2025 and achieving a 100 per cent mix of renewables and natural gas with 70 per cent of EBITDA from renewables.

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 emission 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").

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 operations. The GSSC then supports the Board in developing Company-wide climate change strategies, policies and practices. The GSSC also reviews environmental protection guidelines, including 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 ensures climate risks and opportunities are factored into 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 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.

Our Board is composed of individuals with a mix of skills, knowledge and experience critical to our strategy success and business growth. Notably, five of our Board members have identified environment/climate change among their top four relevant competencies.

Role of Senior Management

TransAlta's President and CEO maintains the highest level of oversight on climate-related issues at the executive level. Our business units and corporate functions work closely together to support the executive team in understanding climate-related risks and opportunities. Our executive team reviews risks and opportunities quarterly and reports to the GSSC and AFRC.

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 corporate executive annual incentive plans (short-term incentive or yearly bonus and long-term share incentives) to performance on 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, please refer to the ESG-Linked Compensation in Building a Diverse and Inclusive Workforce section of this MD&A.

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 all scenarios.

TransAlta remains committed to creating a path to resiliency in a decarbonizing world so that we support the goals proposed under the Paris Agreement and those solidified during successive meetings, such as COP26. Our strategy is focused on the operation of our existing assets (wind, hydro, solar, gas, storage and 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 clean 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 2021, we grew our nameplate renewables capacity from approximately 900 MW to over 2,800 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 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. Further, 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. In 2020, we launched WindCharger, a "first of its kind" battery storage project in Alberta 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 through the construction of the Northern Goldfields Solar Project in Western Australia. This project will support BHP in meeting its emissions reduction targets and delivering lower carbon, sustainable nickel to its customers. With a target operation date in early 2023, the Northern Goldfields Solar Project is expected to reduce BHP's scope 2 electricity GHG emissions by 540,000 tonnes of CO_2e over the first 10 years of operation.

In support of our own path to climate resiliency, 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. TransAlta estimates that this is in line with limiting global warming to 1.5°C and, in 2021, committed to setting a science-based emissions reduction target through the Science Based Targets initiative. In addition, we have a target to be carbon neutral by 2050, while growing renewable energy and optimizing natural gas. We are also taking strategic steps to decarbonize the power sector and support the energy transition. In 2021, we completed our conversion of existing Canadian coal assets to natural gas, achieving our goal of transitioning off coal in Canada. In 2021, we also announced our Clean Electricity Growth Plan which will see the Company execute on 2 GW of renewables growth by 2025. In 2025 we will also retire our single remaining coal unit, located in the United States, to complete TransAlta's transition away from coal generation.

To date, we have retired 4,064 MW of coal-fired generation capacity since 2018 while converting 1,659 MW to natural gas. Overall, our converted natural gas units generate nearly 50 per cent fewer CO_2 emissions compared to coal. 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 contributes to the goals of the Powering Past Coal Alliance, which TransAlta joined in November 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 baseload 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 Scenarios

In 2021, we conducted climate scenario analysis to understand risks and opportunities and assess our strategy's resiliency under several 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").

STATED POLICIES (STEPS)

- **"Reflects all of today's announced policy intentions and targets"**
- No carbon price in US or Australia
- Power sector reduces emissions by 45% by 2040
- Natural gas generation capacity increases
- Relies on commercial-ready technologies: wind and solar

SUSTAINABLE DEVELOPMENT (SDS)

- **"On track for net zero by 2070."**
- Carbon price continues in Canada and is set in US and Australia (140 USD/CO_2 tonne by 2040)
- Power sector reduces emissions by 90% by 2040
- Natural gas capacity remains stable
- Beyond wind and solar, relies on battery/storage and some level of CCUS and hydrogen

NET ZERO EMISSIONS BY 2050 (NZE2050)

- **"On track for net zero by 2050."**
- Aggressive carbon price is set in Canada, US, and Australia (205 USD/CO_2 tonne by 2040)
- Power sector reaches net zero emission by 2035
- Natural gas capacity decreases after 2030 and is coupled with CCUS
- Beyond wind and solar, relies on battery/storage, CCUS, hydrogen, and innovation

Source: World Energy Outlook (2020)

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.

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 figures in 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. It is expected that major grid decarbonization investments will flow into Alberta as many other markets where TransAlta operates 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 of power from natural gas declines as the market shifts towards cleaner power. An additional decline from Canadian oil & 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. Counterintuitively, 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 emission 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.
NZE	By 2040, renewables are expected to comprise over 85 per cent of the total electricity generations in the regions we operate. This surge in renewables will increase competition and drive electricity pricing down. 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 where 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 CO_2e 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.

Top Identified Climate-Related Risks by Scenario

	Increased competition	Decreased demand of natural gas electricity	Increased operational costs
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 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 CO_2e 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 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. Therefore, profits from our natural gas assets are not expected to be affected.
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 where we operate. See more details of our strategy and risk management under the Climate Strategy section and 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 generate nearly 50 per cent fewer CO_2 emissions compared to coal. 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 2025 we will have achieved a 100 per cent portfolio mix of renewables and natural gas with 70 per cent of EBITDA attributable to renewables.	We have taken significant steps to reduce our carbon footprint. In 2021, we achieved a total reduction of 61 per cent compared to our 2015 emission levels. By 2026, we have a commitment to reduce scope 1 and 2 GHG emissions by 75 per cent from a 2015 base year and plan to achieve carbon neutrality by 2050. 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 type 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 specially 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 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 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 where 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 where we operate by 2040. 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. Today we operate over 50 renewable facilities across Canada, the US and Australia. By the end of 2025, 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 low-carbon natural gas generation. Our investments and growth in renewable energy are highlighted by our portfolio of renewable energy-generating assets. From 2000 to 2021, we grew our nameplate renewables capacity from approximately 900 MW to over 2,800 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" 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 through the construction of the Northern Goldfields Solar Project in Western Australia. This project will support BHP in meeting its emissions reduction targets and delivering lower carbon, sustainable nickel to its customers.

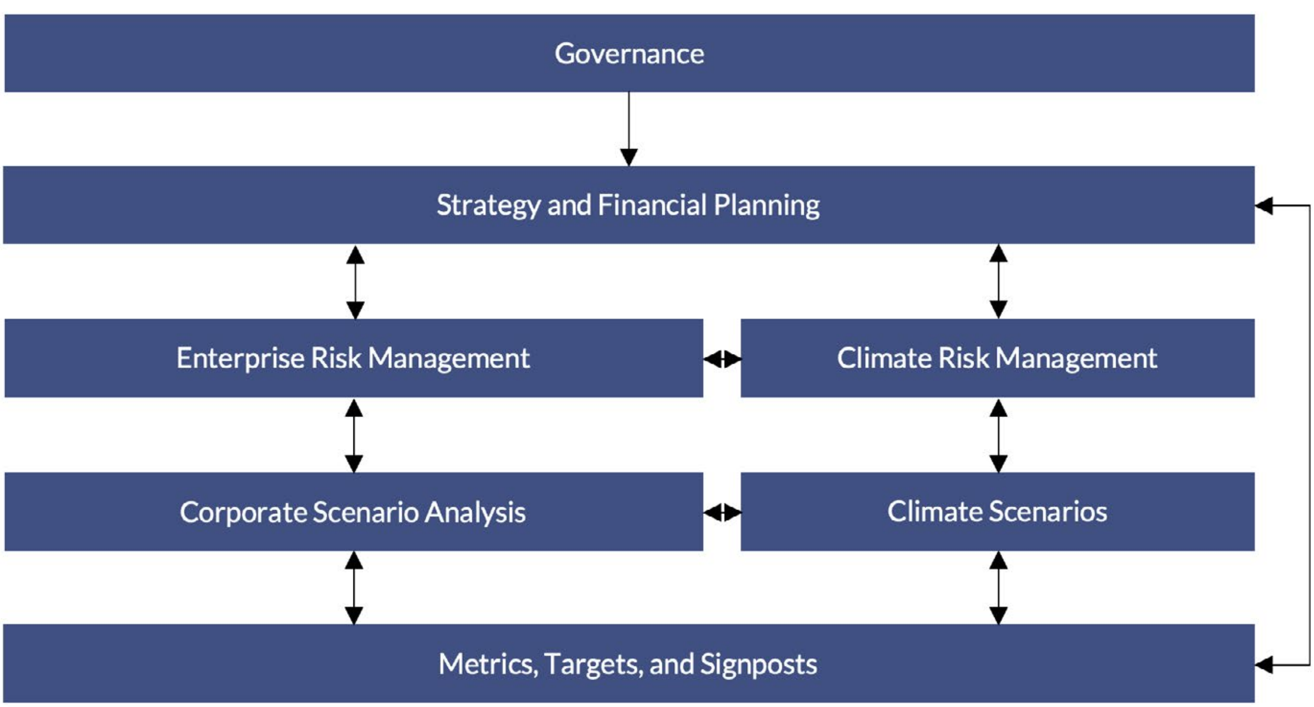
NZE: The most significant risks include increased competition, decreased demand for natural gas and increased operational costs due to increased carbon pricing and emission reduction mandates. The most significant opportunities include a shift toward renewables as the default energy source and new technology 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. As demonstrated in the following figure, 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 strategy and financial planning, risk management, opportunity assessment and planning for uncertainty.

The figure below shows how we integrate climate into our overall risk management strategy:



Managing Climate Change Risks and Opportunities

We actively monitor and manage climate-related risks through our company-wide enterprise risk management 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 the Governance and Risk Management section of this MD&A.

We divide our climate change risks into two major categories as per guidance from the TCFD: (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 please 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.

In 2021, a Supreme Court of Canada decision confirmed the federal government has significant authority to set national carbon pricing standards. We anticipate the federal government will use this authority to align provincial carbon pricing systems with national carbon targets. 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. 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.
- 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 generation.

Management Response

- TransAlta's Clean Electricity Growth Plan will reduce the proportional Company exposure to potential policy and regulatory decisions that negatively impact natural gas generation.
- Our coal-to-gas facilities fit well within government plans to continue providing reliable and competitively priced electricity for consumers and industry.
- Our remaining natural gas facilities 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, directly and through industry associations, to encourage governments to adopt a level playing field within funding and crediting programs so that all new projects receive equitable governments 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, which makes the US policy environment less predictable than in other countries where we operate.

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 (please refer to Management Response below).
- Given overall political uncertainty, renewable growth projects face elevated uncertainty with respect to long-term federal incentive programs.

Opportunities

- Achieving US climate goals requires continued growth in zero-emissions electricity generation. TransAlta's Clean Electricity Growth Plan is focused on providing renewable electricity to contracted customers in a manner aligned with federal and, where applicable, state goals.
- US tax incentive programs offer significant support for new renewable 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 carbon pricing 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 Government of Australia has a 26 to 28 per cent national emissions reduction target over 2005 levels by 2030 and a goal to achieve a net-zero national economy by 2050. The government has stated it does not plan to adopt carbon pricing but intends to offer incentives for energy transition. 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 (please refer to Management Response below).

Opportunities

- Our Clean Electricity Growth Plan is focused on building new, clean generation in Australia and other markets. Government policies and funding programs are generally supportive of the types of projects contemplated within TransAlta's strategy.

Management Response

- TransAlta's assets are predominantly contracted 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 technologies team and our ERM process. Examples of technology risks and opportunities include infrastructure changes (such as 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 farms in southern Alberta. In 2021, we agreed to deliver 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 are actively accelerating our renewable growth strategy, with $3 billion in investment and 2 GW of growth planned by 2025. We will continue monitoring new technologies such as storage, hydrogen and CCUS for future deployment. For further information on technology and innovation, please refer to the Technology Adoption and Innovation Focus 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 20 renewable projects that are either under construction or in the development stage. We are committed to growing our clean energy fleet and since 2019 have added over 400 MW of renewables and storage, including utility-scale battery storage. In 2021, we retired or converted 2,260 MW of coal generation. Further, we established approximately 3 GW of wind and solar pipelines and organized Canadian, US and Australian clean energy growth teams. 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 transition away from coal mitigates this reputational risk. As consumer trends move in favour of renewable and clean 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 Impact 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.

Acute Physical

We have operating assets in three countries and varied geographic locations, many of which could be impacted by extreme weather events. We are thus continuously evaluating 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. For further information on weather-related risks, please refer to Weather in the Progressive Environmental Stewardship section of this MD&A.

Chronic Physical

We continuously investigate the physical impacts of chronic climate change 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

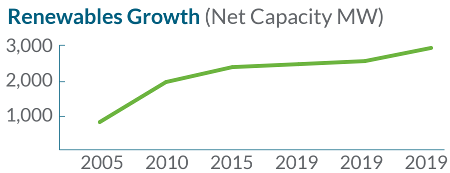
Metrics and Targets

At TransAlta, climate change management and performance are a top priority. We establish our goals and targets with reference to the UN SDGs and the Future-Fit Business Benchmark. Our sustainability targets support the long-term success of our business. Over time, we have set ourselves apart with actions that demonstrate climate change leadership, including reducing our annual emissions by over 19 million tonnes of CO_2e since 2015. We are committed to evolving our leading sustainability target-setting process, ensuring our goals are meaningful and ambitious, and securing TransAlta's competitiveness, both today and in the future.

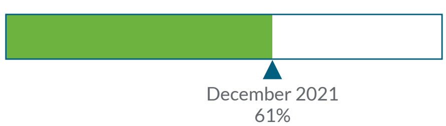
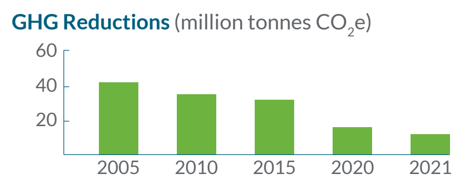
The following targets outline our pathway to becoming a leader in clean, affordable, and reliable power. We establish goals and targets to manage key and emerging sustainability issues and improve our performance in these areas. We will continue to evolve and adapt our targets to focus on key anticipated climate-related issues.

Progress towards our climate-related targets are presented below:

Clean Energy Growth

Target	Develop new renewable projects that support our customers' sustainability goals to achieve both long-term power price affordability and carbon reductions	No further coal generation; 100% of our owned net generation capacity from renewables and gas
Year	2021	2025
Progress (% of target met)		
Notes	In 2020, we developed WindCharger, a "first of its kind" battery storage project; in 2021, we agreed to provide renewable solar electricity supported with a battery energy storage system to BHP through the construction of the Northern Goldfields Solar Project in Western Australia. In 2021, we also entered into long-term PPAs for the off take of 100 MW from our Garden Plain wind project in Alberta and 100 per cent of our 300 MW White Rock East and White Rock West wind projects in Oklahoma.	One of our major strategic goals is to be coal-free in Canada by the end of 2021 with the remaining US unit retiring by 2025. In 2021, we achieved full phase-out of coal in Canada. This means TransAlta's thermal facilities in Alberta have been fully transitioned to a 100% natural gas operation. The Highvale coal mine was closed. In the US, Centralia Unit 1 retired on Dec. 31, 2020, and the remaining unit is set to retire on Dec. 31, 2025. Thus far, we have retired or converted 90% of our existing coal fleet and will retire the remaining 10% by 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."

Emissions Reduction

Target	By 2026, achieve a 75 per cent reduction of scope 1 and 2 GHG emissions from a 2015 base year.	Achieve carbon neutrality
Year	2026	2050
Progress (% of target met)		
Notes	We are well on track to achieve our target of 75 per cent GHG emissions reductions by 2026. We estimate that this is in line with limiting global warming to 1.5°C and, in 2021, committed to setting a science-based emissions reduction target through the Science Based Targets initiative. Since 2015, we have reduced our annual GHG emission by approximately 19.7 million tonnes CO_2e or 61%. In 2021, we reduced approximately 3.9 million tonnes of CO_2e over 2020 levels.	In 2021, we adopted a target to be carbon neutral by 2050. We believe carbon neutrality provides flexibility as we shape our strategy over the coming decades, and we believe our clean electricity strategy has us well positioned to support us achieving this.
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."

GHG Disclosures

Our 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 we operate.

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

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. The Clean Energy Regulator in Australia amended global warming potentials in August 2020. Therefore, the use of global warming potentials in our GHG calculations related to our Australian assets differs from the rest of our fleet. Applying harmonized global warming potentials across our fleet would result in a minor variance to our overall calculated GHG totals.

Our 2021 GHG data is 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.

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	**2021**	2020	2019
Scope 1	**12.4**	16.3	20.5
Scope 2	**0.1**	0.1	0.1
Total GHG emissions	**12.5**	16.4	20.6

Year ended Dec. 31	**2021**	2020	2019
Hydro	**0.0**	0.0	0.0
Wind & Solar	**0.0**	0.0	0.0
Gas	**6.5**	7.7	9.3
Energy Transition	**6.0**	8.6	11.3
Corporate and Energy Marketing	**0.0**	0.0	0.0
Total GHG emissions	**12.5**	16.4	20.6

Year ended Dec. 31	**2021**	2020	2019
Australia	**1.0**	1.1	1.1
Canada	**7.9**	9.4	11.6
US	**3.6**	5.9	8.0
Total GHG emissions	**12.5**	16.4	20.6

In 2021, our GHGs emissions (scopes 1 and 2) were estimated to be 12.5 million tonnes as a result of normal operating activities. Compared to 2020, this represents a reduction of approximately 24 per cent or 3.9 million tonnes CO_2e. Reductions in GHG emissions were primarily due to shutdowns during coal-to-gas conversions and coal unit retirements. Because we sell the environmental attributes generated from our renewable energy facilities, we do not subtract this amount from our total emissions, but it should be noted that TransAlta's customers are reporting GHG reductions using our renewable energy assets, projects and operations.

GHG emissions are verified to a level of reasonable assurance in locations where 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 highlights our scope 1 and 2 GHG emission reductions since 2015 and our targeted emissions in 2026 (in line with our new GHG target). 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)**	2021	2015
Total GHG emissions (million tonnes CO_2e)	**8.1**	12.5	32.2

We estimate our scope 3 emissions in 2021 to be in the range of four million tonnes of CO_2e, which is primarily attributed to our non-operated joint venture interests.

The table below shows the alignment of our climate change management disclosure with TCFD recommendations.

Recommended Disclosures	**Location**
Governance	
Describe the board's oversight of climate-related risks and opportunities	Oversight by the Board of Directors
Describe management's role in assessing and managing climate-related risks and opportunities	Role of Senior Management
Strategy	
Describe the climate-related risks and opportunities the organization has identified over the short, medium, and long term	Key Scenario Findings
Describe the impact of climate-related risks and opportunities on the organization's businesses, strategy and financial planning	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	Climate Scenarios, Key Climate Scenario Findings
Risk Management	
Describe the organization's processes for identifying and assessing climate-related risks	Climate Change Strategy
Describe the organization's processes for managing climate-related risks	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	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	Climate Change Metrics and Targets
Disclose scope 1, scope 2 and, if appropriate, scope 3 greenhouse gas (GHG) emissions and the related risks	Climate Change Metrics and Targets
Describe the targets used by the organization to manage climate-related risks and opportunities and performance against targets	Climate Change Metrics and Targets

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.

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 men and women, 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 do have governance practices in place for the protection of human rights.

Our Human Rights and Discrimination Policy communicates our commitment to human rights in our operations and supply chain to ensure that our personnel policies and practices in our global operations will 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. In 2021, we launched mandatory Code of Conduct training for employees to complete before signing the Code of Conduct. The training completion rate was 100 per cent. 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 in the provision of 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, we report under the Australian 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.

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 people. Our core values of safety, innovation, sustainability, respect and integrity represent how we do business and engage with Indigenous people. Our commitment to Indigenous relations is led by a centralized corporate team who foster a relationship-based approach, involving employees at each facility 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 four key areas: community engagement and consultation; business development; community investment; and employment. We ensure that TransAlta's principles for engagement are upheld and that 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, minimizing potential project delays. We strive to maintain relationships through the life cycle of our operations, 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 addition, TransAlta is a member of the Canadian Council for Aboriginal Business ("CCAB") and is certified at the Bronze level in the CCAB's Progressive Aboriginal Relations program.

Participation in Indigenous Ceremonies

In 2021, TransAlta was honoured to participate in three ceremonies with Elders and other representatives from Indigenous communities in Canada: a Water Ceremony with the Aamjiwnaang First Nation; a Water Ceremony with the Wesley First Nation of the Stoney Nakoda Sioux Nations; and a Blessing Ceremony with an Elder from Paul First Nation at the Highvale mine for tree planting.

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 2021, TransAlta provided more than $375,000 to support Indigenous youth, education and employment programs, representing 13 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, Nakota Sioux and Stoney. Volunteers from TransAlta travel to the school to deliver Christmas gifts, providing both our employees and the students the opportunity to engage with each other. Due to the COVID-19 pandemic, this tradition has been conducted remotely. In 2021, more than 200 Christmas gifts were purchased for students at Mother Earth's Children's Charter School and Wihnemne School on Paul First Nation.

- **Spirit North** – TransAlta is proud to support Spirit North, a national charitable organization that uses land-based activities to improve the health and well-being of Indigenous youth. Through the transformative power of sport and play, participants learn important lessons, discover untold potential and build the confidence and courage needed to overcome the hardships Indigenous youth often face.

- **Southern Alberta Institute of Technology Gap Program** – This program provides critical financial support needed for aspiring Indigenous students who require high school upgrading in order to qualify for a trade program where there is a "gap" in available funding.

- **The Banff Centre for Arts and Creativity** – This year, TransAlta continued our ongoing partnership with the Banff Centre and supported scholarship funding for Indigenous community members to participate in leadership training.

- **Books In Homes** – Funding supports an early literacy program for the children of Tjiwarl Aboriginal Corporation members in Western Australia.

- **Mount Royal University Foundation** – Continued partnership with the Mount Royal University Foundation in support of the Indigenous Family Housing Program, which features an Indigenous family tipi in an outdoor space dedicated to Indigenous students and supporting Indigenous cultural programming.

- **Indspire –** Continued support for Indspire, a national Indigenous registered charity. Through this program, 14 bursaries of $3,000 each were given to recipients from the following communities: Blood (Kanai) First Nation, Ermineskin Cree Nation, Enoch Cree Nation, Montana First Nation, Simpcw First Nation and Squamish First Nation.

- **Diamond Willow Youth Lodge** – In partnership with the United Way of Calgary & Area, designated funding was provided to the Diamond Willow Youth Lodge, 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.

Indigenous Cultural Awareness Training for TransAlta Employees

In 2021, we adopted a new sustainability target that will see that all employees complete Indigenous cultural awareness training by the end of 2023. We believe education is the foundation to ensuring respectful and strong relationships with Indigenous peoples into the future.

In addition to our training commitment, in 2021 our Indigenous Relations team led three company-wide cultural awareness initiatives in recognition of National Reconciliation Week in Australia and National Indigenous History Month and National Indigenous Peoples Day in Canada.

In 2021, September 30 marked the first National Day for Truth and Reconciliation, which is a federal statutory holiday in Canada and TransAlta chose to adopt this day as one of its statutory holidays. This is an important day for Canadians to take time to pause, reflect and focus to deepen their awareness and understanding of the Canadian residential school system. This day also provides an opportunity to consider how each of us can contribute to ongoing reconciliation with Indigenous peoples. Coinciding with the announcement of unmarked graves of Indigenous school children in British Columbia and Saskatchewan, TransAlta lowered the flags at its Canadian operations for one hour for each grave that was discovered. TransAlta's Executive Leadership Team delivered a National Day for Truth and Reconciliation Town Hall online event.

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.

TransAlta Stakeholders

To act in the best interests of the Company and to optimize the balance between financial, environmental and social values for both 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 conducted for each facility 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 (NGOs)	Community associations and organizations	Connecting 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 & gas associations/Industry	Railroad owners
Customers	Think tanks	Utility owners
Municipalities	Academics	Employees

Stakeholder Engagement

In order to run our business successfully, we maintain open communication channels with our stakeholders. We commit 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 with each stakeholder to identify and to mitigate further issues.

Examples of our methods of engagement are listed in the following table.

Information & Communication	Dialogue & 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 and sustainable 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 and maintain engaged communication throughout operations to decommissioning. Examples of stakeholder engagement in 2021 include: the WaterCharger Battery Energy Storage Project; the closure of the Highvale mine; the suspension of the Sundance Unit 5 Repowering Project; the coal-to-gas transition at our Alberta plants; and noise and aircraft lighting detection systems at the Antrim Wind Energy facility in New Hampshire.

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:

- Sustainable 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.

Across our business in Canada, the US and Australia, we provide on-site generation for large mining and industrial customers. This requires us to be continually engaged 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 develop renewable energy facilities to support customers achieving their sustainability goals and targets, such as 100 per cent renewable power targets and/or GHG reduction targets. Production from renewable electricity in 2021 resulted in the avoidance of approximately 2.6 million tonnes of CO_2e for our costumers.

Examples of renewable energy projects in 2021 include our Garden Plain wind project in Alberta, which has a 130 MW capacity and is subject to a PPA with Pembina, our White Rock Wind Projects in Oklahoma with a 300 MW capacity, which is subject to a PPA with a single offtaker, and our Northern Goldfields Solar Project with a battery energy storage system in Western Australia, which has a 48 MW capacity and is subject to a PPA with BHP.

For further details on how we support our customers' sustainability objectives, please refer to Applied Technologies in the Technology Adoption and Innovation Focus section of this MD&A.

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 the customer of sites that operate 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.

Community Investments

In 2021, TransAlta increased its community investments by 36 per cent and contributed approximately $3.0 million in donations and sponsorships (2020 - $2.2 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 $1.1 million for the United Way. TransAlta has been supporting the United Way for over 30 years and has contributed more than $20 million over that time. In 2021, TransAlta made a number of other significant investments. Key highlights for the year included:

- **Calgary Health Foundation** - In 2021, TransAlta partnered with the Calgary Health Foundation to support the Newborn Needs campaign in support of the development of a new Foothills Medical Centre Neonatal Intensive Care Unit ("NICU"), serving all of southern Alberta. TransAlta provided an initial $1 million of support in 2021, as part of a $2 million total commitment over a five-year term. The NICU will be a Centre of Excellence for Calgary, Alberta, Canada and the world.

- **The Calgary Stampede Foundation** – Founded in 2017, the TransAlta Performing Arts Studio at Stampede Park continues to provide a year-round facility for the Calgary Stampede Foundation and Calgary's youth performing arts groups to rehearse, train and celebrate the arts.

- **TransAlta Tri-Leisure Centre** – The TransAlta Tri-Leisure Centre is a sporting and recreation destination for many active and involved residents from the communities of Parkland County, Spruce Grove and Stony Plain in Alberta. At the facility, thousands of local residents and many of our employees participate in a wide range of sporting and cultural activities and join together in many community causes.

- **Calgary Reads** – TransAlta was proud to continue to support this organization in 2021, which is dedicated to supporting the improvement of literacy skills for children in Calgary.

- **International Women's Day** – As part of TransAlta's International Women's Day Celebration, the company provided donations to five organizations that support women in the jurisdictions where we operate:

    - **Rise Kira House (Perth, Western Australia)** – the Rise Kira House is a 24-hour service supporting young women (aged 14-18) leaving family and domestic violence.

    - **Women's Interval Home of Sarnia-Lambton (Sarnia, Ontario)** – The Women's Interval Home provides emergency shelter and counselling services to abused women and their children. This includes 24-hour emergency and short-term shelter, support, individual and group counselling, transitional services and child-witness counselling services.

    - **Elizabeth Fry Society of Northern Alberta (Edmonton, Alberta)** – The Elizabeth Fry Society of Northern Alberta partners with communities from Red Deer to Fort McMurray (including rural and Indigenous communities) to address the unique access to justice needs and gaps in services that affect vulnerable individuals.

    - **Women United (Lewis County, Washington)** - Women United's mission is to positively impact the lives of women and children living in poverty in Lewis County by encouraging self-sufficiency and empowerment. Women United gathers local women who seek to understand the issues facing the community and then roll up their sleeves to help. They operate as an affinity group of the United Way of Lewis County and as such, work within its mission to lift 30 per cent of Lewis County families out of poverty by 2030.

    - **The Women's Centre of Calgary (Calgary, Alberta)** – The Women's Centre provides a safe and supportive space accessed by thousands of women in Calgary. Supports include: poverty and hunger, family breakdown, parenting, homelessness, unemployment, health and education, immigration and settlement, domestic violence, isolation and loneliness, life transitions and discrimination. Forty-one per cent of the women who access the services and volunteer their time are living in poverty.

- **Calgary Pride** – As part of TransAlta's Pride Celebration in 2021, the company was happy to sponsor the 2021 Calgary Pride Festival and Parade. Calgary Pride aims to create spaces that ensure LGBTQ2+ belonging and celebration. The Calgary Pride Festival and Parade takes place each Labour Day long weekend, with thousands gathering in celebration of gender and sexual diversity.

- **Leinster Community School** – Funding was provided for an upgrade to the kindergarten playground area to create a new play-based learning environment, focused on sustainability.

- **Heart Kids** – Support was provided for the annual 2021 charity walk for Heart Kids, Australia's only not-for-profit organization solely focused on supporting and advocating for people impacted by childhood heart disease.

- **Energy Transition Support** – On July 30, 2015, we announced a US$55 million community investment over 10 years to support energy efficiency, economic and community development and education and retraining initiatives in Washington State. The US$55 million community 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 & Community Development Board (US$20 million) and the Energy Technology Board (US$25 million). To date, the Weatherization Board has invested US$8 million, the Economic & Community Development Board US$15 million and the Energy Technology Board US$10 million. Specific projects that the boards funded in 2021 include financial support to learning centres (the United Learning Center project, a Boys & Girls Club and the Discover Children's Museum), a project to install the first renewable energy project in Washington state that generates electricity by harvesting excess pressure from municipal water pipeline, and the installation of a shore power connection point at the Bell Street Cruise Terminal at Pier 66 in Seattle, Washington. The shore power connection will allow vessels with shore power technology to plug into the local electrical grid, which reduces GHG emissions and the burden of diesel exposure to people who live, work and visit along the Seattle waterfront.

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, 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.

In 2021, the Board approved our revised Supplier Code of Conduct that 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 as they pertain to 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.

Engagement and Board Communication

The Board believes that it is important to have constructive engagement with its shareholders and other stakeholders and has established means for the shareholders of the Company and other stakeholders to communicate with the Board. For example, employees and other stakeholders may communicate with the Board through the AFRC by writing to the AFRC or by making submissions via the Company's toll-free telephone or online Ethic Helpline (please refer to Risk Controls — Whistleblower System in the Governance and Risk Management section of this MD&A for more details). Shareholders are also invited to communicate directly with the Board under the Company's Shareholder Engagement Policy, which outlines the Company's approach to proactive director-shareholder engagement at and between the Company's annual shareholders meetings. Under the Shareholder Engagement Policy, shareholders can submit questions or inquiries to the Board, to which the Company will respond. Our Shareholder Engagement Policy is available in the Governance section of the Investor Centre on our website. Shareholders and other stakeholders may, at their option, communicate with the Board on an anonymous basis. In addition, the Board has adopted an annual non-binding advisory vote on the Company's approach to executive compensation (i.e., say-on-pay).

The Company is committed to ensuring continued good relations and communications with its shareholders and other stakeholders and regularly evaluates its practices in light of any new governance initiatives or developments in order to maintain sound corporate governance practices. Throughout 2021, representatives of the Board engaged extensively with the Company's significant shareholders. Specifically, since Jan. 1, 2021, independent members of the Board have met with 12 shareholders representing approximately 39 per cent of the Company's total issued and outstanding common shares. In addition, independent members of the Board engaged with Proxy Advisory firms to discuss a number of topics of relevance to the Company and its stakeholders, including the Company's strategic direction, executive compensation, ESG practices and Board composition and diversity.

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 people.

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 includes an emergency management policy and standard, which sets an expectation for employees to continuously prepare for emergencies. The program has executive sponsorship. 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 able to respond 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.

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 (the Chief Talent & Transformation Officer, or their designate), co-ordinate messaging with any applicable external agencies and, if necessary, deploy to an incident site.

Annual training 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 a sustainable program across the organization.

The Company continues to operate under its business continuity plan in response to the global pandemic declared in March 2020. For more information, please refer to COVID-19 in the Significant and Subsequent Events section of this MD&A.

Data and Digital Asset Protection

We work hard to protect our digital assets, including our corporate data and our digital identities that give us access into line of business applications. Cybersecurity risks that work to compromise these assets include the manipulation of data integrity, system and network hacking, use of social engineering tactics through email phishing, compromise of operations and infrastructure through the use of ransomware, credential breaches, attacks introduced through unknowing third-party vendors and service providers, as a well as malware. 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 cyber risks and threats through a comprehensive and multi-faceted program. Through this program, TransAlta continually implements measures and controls to proactively mitigate internal and external cybersecurity risks and threats posed to the organization, and to deal efficiently and effectively with threats.

Please 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 a 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 2021, we improved 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 ED&I is found in our workplace, among our co-workers who at all levels advocate for the core values of equity and inclusion. We believe a strong focus on ED&I will drive performance in innovation, improve service to our customers and positively impact the communities that we all live in.

In 2021, TransAlta's ED&I Council developed our five-year ED&I strategy to achieve the goals and set out a course to attaining the aspirations set out in our ED&I Pledge. Our five-year ED&I strategy was approved by the Board and sets out key milestones for the annual plans from 2021 to 2025. The first phase of this strategy focuses on raising awareness to build a foundation and common understanding upon which our co-workers can have meaningful conversations to learn about one another. The second phase centres around reinforcing and embedding inclusive behaviours.

We continued to expand our ED&I platform in 2021 by offering employees a variety of training, education and awareness on ED&I such as webinars, employee engagement sessions, articles, videos and blogs. After completing our inaugural 2020 ED&I Census, which was delivered by a third party and was sent to all employees to understand our demographics and our experiences in the workplace, we put actions into place to address pain points in 2021. This included celebrating International Women's week and Pride month with several activities, hosting a number of guest speakers on a variety of topics and implementing partnerships for mentorship and Employee Resource Groups opportunities.

Our 2021 ED&I Census results were benchmarked to those of other companies in our industry and within Canada. The results demonstrated a marked improvement of our workforce feeling a greater sense of inclusion and belonging. In addition, our ED&I Census inclusion results were above the energy industry average meeting the inclusion scores of leading ED&I corporations in Canada. In our ED&I Census we received an above industry average response rate of 58 per cent. Of the respondents that completed the ED&I Census, we understand that 30 per cent of the workforce identifies as female, 24 per cent of the workforce identifies with a racial or ethnic minority group, two per cent of the workforce identifies as members of LGBTQ2+ community and 10 per cent of the workforce are people with disabilities.

In 2021, we received market recognition for our ED&I efforts and were certified by a third party for our commitment to measuring, tracking and improving ED&I. We have been recognized for our efforts to measure and set targets to increase diversity, while regularly collecting data on our co-workers' experiences to identify bias and barriers faced by underrepresented groups and implementing programs and policies designed to unlock specific challenges while tracking results. We have incorporated diversity metrics into TransAlta's 2021 short-term incentive plan for our employees.

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, 2021, women made up 38 per cent of our executive officer team and 42 per cent of our Board. These percentages are higher than our peers in Canada. Industry research highlights that the percentage of Board seats held by women from all disclosing Canadian TSX-listed companies in Canada is 22 per cent and the average percentage of women on executive teams is 18 per cent.

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. Our goal to achieve 40 per cent women across the entire workforce by 2030 is ambitious considering the majority of the operational roles are currently male dominated. Currently, women employees represent 24 per cent of all employees.

TransAlta was once again added to the Bloomberg Gender-Equality Index in 2021. Inclusion in the index recognizes our comprehensive investment in workplace gender equality and our commitment to driving progress by developing inclusive policies and disclosing data using Bloomberg's gender reporting framework. In 2021, the Company received the Globe and Mail's Women Lead Here award, which evaluates publicly traded Canadian companies' ratio of female-identifying to male-identifying executives in the top three tiers of executive leadership.

In 2021, in celebration of International Women's Day 2021 theme #ChooseToChallenge, TransAlta delivered a week-long campaign to highlight the contributions of women in the workplace with live events in recognition of this momentous day as well as training, challenges and a webinar with one of our female Board members. During these celebrations, we launched our Women in Trades Scholarship with 13 different educational institutions for eligible students enrolled in post-secondary trade programs. We are committed to investing in our communities through meaningful impact and the opportunity to enhance the quality of life wherever we operate. The Women in Trades Scholarship is intended to assist women in obtaining an education in trades by showcasing and rewarding successful female role models.

We also pioneered a female apprenticeship program in our Generation business to strategically target the recruitment of high potential female students and train them to gain valuable experiential learning in the trades. The female apprenticeship program has created a pipeline of future female talent for the Company and has resulted in us being able to creatively target, recruit, hire and retain the first-ever female wind technicians, as well as the first females in the roles of instrumentation technician, electrical technician and power plant operator in our gas fleet in Alberta.

Workforce Health and Safety

The safety of our people, communities and the environment is one of our core values. At TransAlta, we operate large and often complex facilities. The environments in which we work, including Canadian winters and the Australian outback, can add additional challenges to keeping our employees, contractors and visitors safe. Each year we invest significant resources into improving our safety performance, including positively enhancing our safety culture. At meetings of more than four people, we have a practice of starting the meeting with a "safety moment," which helps share key safety learnings across the Company.

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.

In 2021, we continued to progress our safety culture transformation despite an unprecedented and extraordinary challenge due to COVID-19. To reinforce behavioural safety, several training and capability-building initiatives were delivered. TransAlta conducted 90 one-hour leadership peer board sessions with participation by Generation leaders from across the fleet. We also implemented and rolled-out our fleet-wide app for Occupation Hazard Assessment. This app supports hazard recognition by identifying hazards and associated controls for tasks related to specific occupations.

Our Total Recordable Injury Frequency ("TRIF") result for 2021 was 0.82 compared to 0.81 in 2020. TRIF tracks the number of more serious injuries, and excludes minor first aids, relative to exposure hours worked. Our TRIF performance year over year has remained relatively unchanged. In 2021, we established an ambitious target of 0.61 and while we did not meet this target, we will continue to work to achieve our goal in the future. In 2021, substantial progress was made on initiatives related to our three key targets: mature our safety culture, assess and address risk tolerance, and standardize safety information and technology. In 2022, we are expanding behavioural safety training to all employees in order to provide them with tools to take control of their behaviours, and consequently, improve our safety results. This training reinforces our journey to create a psychologically safe environment in our workplace as it encourages personal accountability towards safety.

Safety at TransAlta (employees and contractors)	**2021**	2020	2019
Lost-time injuries	**3**	5	5
Medical aids	**9**	9	7
Restricted work injuries	**5**	2	3
Exposure hours	**4,134,000**	3,948,000	4,108,000
Total Recordable Injury Frequency (TRIF)	**0.82**	0.81	0.73

In addition to TRIF, we have also introduced Total Safety Report Frequency as a key safety metric in our 2021 annual incentive compensation. This is a leading indicator that measures Total Safety Reports (hazard, near miss and positive observations) per worker per year. Total Safety Reports are proactive in nature and demonstrate the actions we are taking to identify and prevent an injury or loss from occurring. In this way, we not only manage incidents if they do occur, but methodically work to prevent them from arising in the first place. In 2021, we recorded 7.35 reports per worker, which is above our target of 5.50.

As a demonstration to TransAlta's commitment to safety, SunHills Mining LP was awarded the Safety Excellence Award from the Alberta Mine Safety Association in June 2021. This award is for best safety performance of all Alberta mines under one million workforce hours based on 2020 performance.

Organizational Culture and Structure

Our employees are central to value creation. Our corporate culture has evolved and adapted throughout our more than 110-year heritage. Our core values are safety, innovation, sustainability, respect and integrity. These five core 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.

As of Dec. 31, 2021, we had 1,282 (2020 — 1,476) active employees. This number has decreased by 13 per cent from 2020 levels, following a reduction in positions in our coal fleet as part of our conversions to gas and ceasing mining operations. With approximately 33 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 2021 to help facilitate effective pace and decision-making in our organization. Our business operates four generating segments, with Gas, Wind and Solar, Hydro and Energy Transition. The Energy Transition is a new segment as described in the Segmented Disclosures under the Segmented Financial Performance and Operating Results section of this MD&A. In addition, our Energy Marketing segment optimizes our asset fleet and trades electricity and other energy commodities. Our Corporate segment, including finance, legal, administrative, business development and investor relations functions, oversees our business and provides strategic alignment. The Company also includes a Shared Services division that oversees our information technology, supply chain, human resources, engineering and accounting functions. The consolidation and centralization of these functions has allowed us to streamline, standardize and, where appropriate, automate these functions while reducing costs and improving service delivery across the organization. Our operations portfolio is run by a single leadership team, which provides operational and financial synergies, enhancing our competitiveness.

TransAlta is committed to improving its internal work environment and the way that employees perceive their work and the Company. We track a broad number of factors to provide us insight into our progress and we use a third party to assist us in tracking our progress on an annual basis. We have made continual and notable improvements year-over-year and continue to target further improvements as we look forward.

Employee Retention and Recognition

ESG-Linked Compensation

At TransAlta we have linked our ESG performance to our employees' compensation, including our executive leadership team. Our corporate executive annual incentive plans (short-term incentive or annual bonus and long-term share incentives) are linked to TransAlta's performance (i.e., pay for performance). The targets and remuneration framework are reviewed and approved annually by our Board. In 2021, 20 per cent of our corporate annual incentive plan was linked to achieving specific ESG objectives: 10 per cent related to the completion of CO_2 reduction projects at existing facilities and diversity and inclusion and organizational health performance, and 10 per cent was linked to workers' safety. A further 20 per cent of our corporate 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 and strong renewables growth.

Employee Retirement Savings Programs

TransAlta is an attractive employer in all three countries in which we operate. We provide compensation to our employees at levels that are competitive in relation to their respective location. We strive to be an employer of choice through our total rewards programs, which include various incentive plans designed to align performance with our annual and longer-term targets, as determined annually by the Board.

Retirement savings plans are an example of rewards we provide. We have registered pension and savings plans in Canada and the US. The plans cover substantially all employees of the Company, its domestic subsidiaries and specific named employees working internationally. These plans have defined benefit ("DB") and defined contribution ("DC") options. The Canadian and US DB pension plans are closed to new entrants, with the exception of the Highvale mine (SunHills) pension plan acquired in 2013. The US DB pension plan was frozen effective Dec. 31, 2010. The plans are funded by the Company in accordance with governing regulations and actuarial valuations.

We also offer some optional plans for Canadian employees to enhance their financial wellness and retirement savings, with group RRSP and TFSA plans.

In Canada there is an additional non-registered supplemental pension plan ("SPP") for executive officers whose annual earnings exceed the Canadian income tax limit. The DB SPP was closed as of Dec. 31, 2015, and only current executive officers were grandfathered in the plan. A new DC SPP commenced for executive members hired after Jan. 1, 2016.

In Australia, employees can nominate a superannuation fund for superannuation contributions. The Australian superannuation scheme is compulsory for employers with contributions required at a rate set by the government.

Other Employee Benefit Programs

TransAlta provides competitive benefit programs for most of our employees (options are dependent on the countries in which we operate). We also provide benefit programs based on negotiated union agreements in certain locations. Our flexible benefit plans provide employees and their families with choices of coverage including, among others, extended health, dental, vision, life insurance, critical illness, accident, disability and a health spending account.

On an annual basis, TransAlta recognizes our top achievements through the President's Awards. In 2021, we added an ED&I award. This award recognizes employees who significantly contributed towards TransAlta's target of a 40 per cent female workforce by 2030 and TransAlta's ED&I objective of creating a workplace where all employees feel they belong.

In 2021, TransAlta launched Wellness Wednesdays. This provides employees with weekly awareness, tips and tools on "wellness" topics. TransAlta's focus on organizational health remained in 2021 through the implementation of nine priority practices into all facets of the organization.

Talent and Employee Development

Talent and employee development is viewed as a key pillar of organizational health. Investing in our employee development enhances employees' skills and improves productivity and engagement. This contributes to a strong corporate culture that provides value for TransAlta.

In 2021, we expanded the content and topics in our Professional Development Library, which was launched in 2020. This includes adding a second library for ED&I articles and resources. This library has had over 3,000 hits and over 300 unique users. Important dates and definitions are explained here as well as tips on ED&I best practices such as land acknowledgments and empathetic thinking.

To increase cross-functional internal development opportunities, we created our Opportunity Board. On this Opportunity Board, leaders post opportunities for employees to work on projects within other parts of the organization. Employees then have the opportunity to apply for these projects in order to develop their knowledge and gain experience in a different areas of the business. Eight opportunities were posted, and nine employees were successfully matched to an opportunity during our pilot launch of the board.

Throughout 2021, a Speaker Series of subject matter experts was organized to assist with leadership development and our ED&I journey. Presentation topics included prioritization, constructive conflict, unconscious bias, belonging, allyship, the LGBTQ2+ community and empathy.

Employees and leaders were also offered the opportunity to participate in training focused on working within a remote environment. This training provided leaders and employees with valuable tools to effectively communicate, work productively in a "home" environment and maintain collaboration and connectivity with colleagues across the organization.

Additional internal training is held annually for both leaders and employees. Elevate, a self-directed development program focused on creating a leadership mindset, and Execution Engine, a two-day program that focuses on how to prepare projects, prioritize tasks, improve our communication skills and ensure we are sustaining the work completed by living our health practices. Since launching in 2017, hundreds of employees have participated in these programs.

During 2021, we launched leadership training with Blue Ocean Brain. Partnering with Blue Ocean Brain, a micro-learning consultancy, TransAlta leaders were provided with weekly email drips on best practices relevant to TransAlta's current interests. In addition, Blue Ocean Brain was also engaged to provide 200 leaders with access to their learning library which contains articles, videos, knowledge checks and leadership briefs.

In addition, we extended our partnership with BetterUp, a consultancy providing professional coaching, to provide 1:1 coaching for over 50 leaders. BetterUp coaching is tailored to the individual's needs to allow them to work with their personal coach on areas that are important for them. Since our partnership with BetterUp began in October 2019, our leaders have participated in over 640 coaching sessions over 390 hours.

In 2021, 89 corporate managers and supervisors were enrolled into Sentis' Zero Incident Process ("ZIP") training. ZIP training reinforces our journey to create a psychologically safe environment in our workplace as it encourages personal accountability for ourselves and our work, improves decision-making processes, improves safety attitudes and creates a common language to have constructive conversations. In 2022, Corporate employees will be offered ZIP training.

Customer Relationship Training was designed in 2021 by entering a partnership with Vanry Inc. and tailoring the content with input from our managers in Commercial and Customer Relations. This 20-week series of workshops is currently being built and will be completed by 19 customer-facing leaders and employees in 2022. Topics include connecting with customers, listening for what matters, managing requests and building trust.

In 2021, we commenced the design of two leadership development programs – the Manager Development Program and Executive Development Program. These programs are designed to provide leaders with the skills and knowledge to lead in a changing world and the evolving nature with regards to the future of work. Both programs will be launched in 2022. We also launched leadership training on psychological safety, building and maintaining trust and cultural leadership in 2021. This training will be offered to all employees in 2022.

During 2021, TransAlta has had 28 intern and co-op placements with students in various areas of study including business, communications, finance and engineering. To assist in subsidizing the internship and co-op programs, TransAlta continues to partner with Electricity Human Resources Canada to access government funding. Over $150,000 in wage subsidies were received in 2021.

In addition, TransAlta continued to participate in the Canada Alberta Job Grant, which reimburses employers two-thirds of the cost of approved external training. TransAlta is currently approved to receive over $44,000 to cover training costs from 2021.

Advancing Other Sustainability Factors

In the following sections we outline our progress across other material sustainability factors. The sections cover natural, manufactured, intellectual, and social and relationship capital management as per guidance from the International Integrated Reporting Framework.

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. Adjusted EBITDA from renewable energy generation in 2021 was $584 million (2020 — $353 million). Our revenue in 2021 from environmental attribute sales was $40 million (2020 — $25 million). In addition, in 2021 the sale of coal byproducts and waste-related recycling generated financial value in the range of $15 million to $20 million, which was the same as our range in 2020.

The following are key trends in our natural capital:

Year ended Dec. 31	2021	2020	2019
Renewable energy adjusted EBITDA	**584**	353	341
Environmental attribute sales revenue	**40**	25	28
GHG emissions (million tonnes CO_2e)	**12.5**	16.4	20.6

Environmental Strategy

All energy sources used to generate electricity have some 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, with a goal of 70 per cent of EBITDA from renewables.

Environmental Policy

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 place an increasing emphasis on successful environmental management. The importance of environmental protection is outlined under our Total Safety Management Policy as a corporate responsibility for TransAlta, and the personal responsibility of each employee and contractor working on TransAlta's behalf.

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 (pollutants, metals) 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, including but not limited to: Alberta Environment and Parks; Ministry of the Environment, Conservation and Parks in Ontario; Ministry of Northern Development, Mines, Natural Resources and Forestry in Ontario; Ministry of Forests, Natural Resource Operations and Rural Development in British Columbia; Environment and Climate Change Canada; Fisheries and Oceans Canada; Michigan Department of Environment, Great Lakes, and Energy; Southwest Clean Air Agency in Washington; Washington State Department of Ecology; Washington State Department of Health; US Environmental Protection Agency; the Department of Agriculture, Water and the Environment in Australia; and the Clean Energy Regulator in Australia.

Environmental Performance

Our performance on managing environmental aspects, reducing our environmental impact and capitalizing on environmental initiatives includes the following:

Renewable Energy and Battery Storage

Since 2005, we have added over 1,500 MW in renewable electricity capacity. We operate over 900 MW of hydro energy, and we were an early adopter of wind energy and today operate over 1,900 MW of wind power, including battery storage. In 2015, we made our first solar investment in a 21 MW solar facility in Massachusetts, and we continue to look for opportunities to develop and operate solar energy. In 2020, we commissioned the first utility-scale battery storage project in Alberta, located at our Summerview II wind facility. The project uses Tesla battery technology and has a capacity of 10 MW. In 2021, we agreed to provide renewable solar electricity supported with a battery energy storage system to BHP in Western Australia. For more information, please refer to Applied Technologies in the Technology Adoption and Innovation Focus section of this MD&A.

Natural Gas

Natural gas plays an important role in the electricity sector, providing low-emission baseload and peaking generation to support system demands and intermittent renewable generation as part of a clean electricity transition. TransAlta operates simple-cycle, combined-cycle and cogeneration facilities in Canada, the US and Australia. Natural gas facilities provide highly efficient electricity and, in the case of cogeneration, steam production, directly for customers and for wholesale markets. TransAlta is a significant operator of natural gas electricity in Canada and Australia. In 2021, our thermal facilities in Alberta have been fully transitioned to 100 per cent natural gas operation, which generates nearly 50 per cent fewer CO_2 emissions fueled compared to coal. In aggregate, TransAlta has retired 4,064 MW of coal-fired generation capacity since 2018 while converting 1,659 MW to natural gas.

Coal Transition

As a result of our coal retirements and conversions to gas our energy use, GHG emissions, air emissions, waste generation and water usage will significantly decline. Transitioning off coal will eliminate all of our mercury emissions, the majority of particulate matter and sulphur dioxide emissions ("SO_2"), as well as significantly reduce our NO_x emissions. Our converted or repowered facilities will also use lower carbon natural gas, compared to facilities in other jurisdictions, as new methane reduction regulations in Alberta and Canada will reduce GHGs in the production and processing phase with respect to flaring and venting of methane (fugitive GHG emissions).

In 2021, we ceased coal-fired power generation in Canada. Our Centralia coal facility in the US will be retired by the end of 2025. Coal will be entirely eliminated from our operations by the end of 2025.

Energy Use

TransAlta uses energy in a number of different ways. We burn gas, diesel and coal (to the end of 2021 in Canada and 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 or 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 table captures our energy use (millions of gigajoules). Energy use declined by 31 per cent in 2021 over 2020, primarily as a result of reduced coal use. Some values do not sum to the indicated total due to rounding. Zeros (0) indicate truncated values:

Year ended Dec. 31	**2021**	2020	2019
Hydro	**0**	0	0
Wind & Solar	**0**	0	0
Gas	**118**	138	162
Energy Transition	**74**	141	184
Corporate and Energy Marketing	**0**	0	0
Total energy use (million gigajoules)	**191**	279	346

Air Emissions

Our coal facilities emit 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 will continue reducing air emissions in our existing fleet through our conversion and retirement of coal units in Alberta (completed in 2021) and Washington State (planned completion by the end of 2025). In 2020, we accelerated our target of 95 per cent SO_2 and 50 per cent NO_x emission reductions over 2005 levels by moving the target date from 2030 to 2026. In addition, we increased the stringency of our reduction levels for NO_x to 80 per cent. Since 2005, we have reduced SO_2 emissions by 90 per cent and NO_x by 77 per cent. We continue to capture 80 per cent of mercury emissions at our coal facilities and, by the end of 2025, mercury emissions will be eliminated following the planned retirement of the Centralia facility. Particulate matter and SO_2 emissions will also be virtually eliminated or considered negligible.

None of our Alberta coal facilities are located within 50 kilometres of dense or urban populations, and they all have been converted to gas in 2021. Our Centralia thermal facility in Washington State is 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"). The Centralia thermal 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 low 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 only facilities with air emissions within 49 kilometres of dense or urban environments.

Our total air emissions in 2021 decreased compared with 2020 levels. Specifically, NO_x was reduced 29 per cent, particulate matter was reduced 80 per cent and SO_2 was reduced 42 per cent over 2020 levels. Mercury emissions also decreased by 33 per cent over 2020 levels. Reductions in emissions were primarily due to shutdowns during coal-to-gas conversions and coal unit retirements.

The following table represents our material air emissions. Figures have been rounded to the nearest one thousand with the exception of particulate matter (rounded to the nearest one hundred) and mercury (rounded to the nearest ten):

Year ended Dec. 31	2021	2020	2019
SO_2 (tonnes)	**7,000**	12,000	16,000
NO_x (tonnes)	**15,000**	21,000	26,000
Particulate matter (tonnes)	**790**	4,000	8,000
Mercury (kilograms)	**40**	60	60

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 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. Typically, TransAlta withdraws in the range of 220-240 million m^3 of water across our fleet. In 2021, we withdrew approximately 240 million m^3 (2020 - 230 million m^3) and returned approximately 210 million m^3 (2020 — 200 million m^3) or 87 per cent. Overall, water consumption was approximately 30 million m^3 (2020 — 40 million m^3). Water consumption was lower in 2021 primarily due to shutdowns during coal-to-gas conversions and coal unit retirements.

Our water consumption reduction target is to reduce fleet-wide water consumption (withdrawals minus discharge) by 20 million m^3 or 40 per cent in 2026 over a 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." Our water consumption will fluctuate somewhat over the period of 2020-2025 as we transition off coal, convert and repower gas facilities and ramp production upwards.

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 10 million m^3:

Year ended Dec. 31	2021	2020	2019
Water withdrawal	**240**	230	260
Water discharge	**210**	200	220
Total water consumption (million m^3)	**30**	40	40

Our largest water withdrawal and discharge occurs at our Sarnia gas cogeneration facility (which produces both electricity and steam for our customer). 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 93 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, and 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 stayed dry and 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.

In southern Alberta, our hydroelectric facilities have played an increasingly important water management role following the flood of 2013. In 2021, we renewed for another five years our previous agreement with the Government of Alberta 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 Lakes System (which includes Interlakes, Pocaterra and Barrier) for drought mitigation efforts.

Waste

The importance of environmental protection and managing waste is outlined in our Total Safety Management Policy as a corporate responsibility for TransAlta, and a responsibility of each employee and contractor working on TransAlta's behalf. Our waste data is reported annually to a number of different regulatory bodies.

Our waste reduction target is that by 2022 TransAlta will reduce total waste generation by 80 per cent over a 2019 baseline of 1.5 million tonnes equivalent of waste generation. This is in line with the UN SDGs, specifically, "Goal 12: Responsible Consumption and Production."

In 2021, our operations generated approximately 515,000 tonnes equivalent of waste (2020 — 1.1 million tonnes). Of the total waste generated, 95 per cent was non-hazardous waste and 5 per cent was hazardous waste. In 2021, only 0.2 per cent of total waste generated was directed to landfill. Our 2020 waste data was revised in 2021 after we received final waste manifests as part of the reclamation project at our Mississauga facility. As a result, approximately 23,000 tonnes equivalent were added to Mississauga in multiple waste categories in 2020.

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	2021	2020	2019
Total waste generation (tonnes equivalent)	**515,000**	1,135,000	1,533,000
Waste to landfill (tonne eq.)	**1,000**	11,000	1,000
Waste recycled (tonne eq.)	**31,000**	31,000	6,000
Waste reuse (tonne eq.)	**176,000**	533,000	746,000
% of total waste to landfill	**0.2**	1	0.07
% of total waste: hazardous	**5**	2	1
% hazardous waste to landfill	**0.9**	0.4	0.6

Our reuse waste or byproduct waste is generally sold to third parties. Byproduct sales and associated annual revenue generation typically ranges from $15 million to $20 million. 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.

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. The Company is looking at recovering fly ash that was returned to its original source at Highvale mine to replace this supply, which is used extensively in the concrete industry. 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.

Biodiversity

The importance of environmental protection and biodiversity is outlined in our Total Safety Management Policy as a corporate responsibility for TransAlta, and a responsibility of each employee and contractor working on TransAlta's behalf.

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, please 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 (a greater focus has been given to mining 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 asses 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 (e.g., Wildlife Directive for Alberta Wind Energy Projects, US Fish & Wildlife Service Land-Based Wind Energy Guidelines, etc.). Typically, our renewable projects are greenfield development projects that require a higher level of evaluation compared to our gas projects, which integrate into existing industrial facilities.

In addition, TransAlta provides a detailed wildlife mitigation plan to environmental regulators outlining specific measures that will be employed to mitigate the effects that project construction and operation activities may have on wildlife, wildlife habitat and specific wildlife features identified during environmental studies completed during the development stage.

Each greenfield development project has a detailed stakeholder consultation 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, solving and mitigating stakeholder or Indigenous community biodiversity concerns before filing major permit applications for all of our projects.

Day-to-day operations
At our Alberta operations, in 2021 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 fish 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, the business unit has established the WiSPER (Wind Stewardship Planning and Environmental Reporting) Program. The goal of the program is to provide continuous improvement and ongoing environmental monitoring programs beyond TransAlta's regulatory requirements. This is achieved through periodic verification and inspection programs, and through collaboration with industry and the scientific community to address environmental concerns and impacts. An Operational Environmental Management Plan has been developed for each renewable asset to ensure that our facilities use environmentally sound and responsible practices that are based on a philosophy of continuous improvement of environmental protection through a program of inspection, monitoring and review.

Examples of WiSPER initiatives to support our biodiversity focus include our Avian Protection Program (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 such as raptor nests and sharp-tailed grouse leks), long-term dataset collections (e.g., wildlife studies pre-construction and post-construction) and community wind education programs.

Land Use
The largest land use associated with our operations is for surface mining of coal. Of the three mines we have 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. Reclamation work continued on the Centralia mine in 2021, including the planting of 23,330 trees.

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 has been progressively executed as part of our regulatory approvals, and our target is to have it fully reclaimed by 2046. Approximately 26,000 trees were planted in 2021 at our Highvale mine. In 2021, our reclamation team obtained regulatory approval for our interim reclamation plans, until submission of final reclamation plan in 2022. 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 practice incorporates progressive reclamation where the final end use of the land is considered at all stages of planning and development. Across our mining operations, to date we have reclaimed approximately 12,000 acres (4,800 hectares), which is approximately 38 per cent of land disturbed.

Environmental Incidents and Spills

Minimizing our impact on 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 appropriate initial 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 2021, we recorded two regulatory non-compliance environmental incidents (2020 – two incidents). One incident occurred at our Sarnia cogeneration facility and was a wastewater discharge exceedance from our neutralization sump during water treatment. The second incident was related to regulatory compliance at our Centralia facility that resulted in an environmental permit exceedance when a worker opened the incorrect fan breaker. Both incidents had negligible environmental impacts, but the Centralia incident resulted in one enforcement action and a US$3,100 fine from the regulator.

Regulatory non-compliance environmental incidents follow:

Year ended Dec. 31	2021	2020	2019
Regulatory non-compliance environmental incidents	**2**	2	6

Regarding spills and releases, typical spills that could occur at our operation sites are hydrocarbon-based. Spills generally happen in low environmental impact areas and are almost always contained and fully recovered. It is extremely rare for large spills to occur. 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 estimated volume of spills in 2021 was 6 m^3 (2020 — 4 m^3). Spill volumes in 2021 were higher due to one environmental incident recorded at our Centralia facility. The incident involved the release of mineral oil due to the failure of a phase generator step-up transformer. Spill response and control efforts were initiated immediately following the incident and environmental impacts were negligible and minimized due to the efficient response.

Significant environmental incidents follow:

Year ended Dec. 31	2021	2020	2019
Significant environmental incidents	**0**	6	3

There is a potential that ash ponds associated with our remaining coal facilities 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 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 weather variations from period to period. Variations in winter weather affect the demand for electrical heating requirements. 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 facility. 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.

During the past three years, we have experienced no significant impacts to annual financial results due to deviations from expected weather patterns.

Please refer to the Governance and Risk Management section of this MD&A for further discussion on weather-related risks.

Reliable, Low-Cost and Sustainable Energy Production

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, which is a core ethos of our company. This section covers manufactured, intellectual, and social and relationship capital management as per guidance from the International Integrated Reporting Framework.

Brand Recognition

Our business resilience is enhanced by a purpose-based, long-term and sustainable business strategy: growth in renewable electricity, optimization of our existing natural gas generation, and a commitment to sustainability. TransAlta has operated power-generation assets for over 110 years, which reflects this approach to long-term and sustainable business practices. A long-term commitment to business and partnerships lends itself to goodwill and brand recognition, something we value and do not take for granted. We believe our low-cost and clean electricity strategy, supported by our internal values and sustainable approach to business, will help reinforce and continue to increase our positive brand recognition.

Diversified Knowledge

At TransAlta, we define intellectual capital as our knowledge-based assets. Measuring these assets serves two purposes. First, we seek to understand them so we can improve their management and performance. Second, we seek to understand these assets to communicate their real value. The experience and acumen of our employees enhances our value creation. Our experience in developing and operating power-generation technologies extends to over 110 years, and many of our employees have worked with us for over 30 years. Our energy marketing business complements our knowledge of operating power-generation assets.

Our experience in developing and operating power-generation technologies is highlighted below.

Power-Generation Type	Operating Experience (years)
Hydro	110
Natural Gas	71
Coal	71
Wind	19
Solar	6

For further details, please refer to Customers in the Engaging with Our Stakeholders to Create Positive Relationships section of this MD&A.

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 2021, TransAlta agreed to build the Northern Goldfields Solar Project 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 is participating in the AESO's pilot fast frequency response initiative to support intertie operations. Beyond the fast frequency response initiative, WindCharger introduces a resource with a response time that is unmatched by existing generation technologies and can be operated with a high level of reliability to support the growing need for inertial response 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, please refer to Applied Technologies in the Technology Adoption and Innovation Focus section of this MD&A. For more guidance on cyberattacks, please refer to Public Health and Safety in the Engaging with Our Stakeholders to Create Positive Relationships section of this MD&A. For more information on extreme weather events and natural disasters, please refer to Weather in the Progressive Environmental Stewardship section of this MD&A.

Technology Adoption and Innovation Focus

Technology and innovation are an existing and increasing focus at TransAlta. As we navigate significant macro changes from energy transition, the impacts of climate change and decarbonization, and the continued rise of digital technology, automation and artificial intelligence, we are proactively applying technology solutions across our business. Our conversion of coal units to gas is an excellent example of utilizing useful manufactured capital or infrastructure. We also continue to adopt and apply innovative solutions to meet customer demand for power.

Idea Generation and Project Management

Our Greenlight program continues to be a driving force behind the strong culture of idea generation and problem solving at TransAlta. Led by our Transformation Office, the program emphasizes bottom-up innovation, which means business improvement ideas are generated by employees. These ideas are developed and advanced into business cases, adhering to best practices of project management, to ensure successful implementation of the improvement opportunity. From the initial ideation, to development and delivery, this process is driven entirely by employees, with support from management and the Transformation Office.

Another initiative we promote is the Supplier Innovation Series, which brings in guest speakers from outside TransAlta to discuss innovation. This includes thought leaders on new technologies to discuss conceptual ideas that initiate creative thinking and suppliers that provide insight into commercial applications of evolving technologies. In 2021, we delivered seven sessions on topics such as artificial intelligence, behaviours for achieving success, frontline and corporate worker apps, hydrogen, mobile robots, robotic inspections for boiler and piping systems, and strategic foresight. 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.

Infrastructure Innovation

In 2015, the Government of Alberta introduced regulations designed to end coal-powered generation in the province by 2030. A number of our coal facilities had useful lives beyond 2030 and could be converted to use natural gas. In 2021, our Sundance Unit 5 facility was retired, and Keephills Unit 2, Keephills Unit 3 and Sundance Unit 6 were converted to natural gas. This means TransAlta's thermal facilities in Alberta have been fully transitioned to 100 per cent natural gas operation. In aggregate, the Company has retired 4,064 MW of coal-fired generation capacity since 2018 while converting 1,659 MW to cleaner-burning natural gas. Overall, the converted units generate nearly 50 per cent fewer CO_2 emissions fueled by natural gas compared to coal. Repurposing the facilities rather than decommissioning them supports the concept of reuse 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 at COP26.

Applied Technologies

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 and are now one of the largest wind generators in the country. Today we run a Wind Control Centre that monitors, to the second, every wind turbine we operate across North America. In 2015, we made our first investment in solar technology with the purchase of a 21 MW solar facility in Massachusetts and in 2020 we installed the first utility-scale battery in Alberta at our Summerview II wind facility. As we balance growth with decarbonization, we continue to seek solutions to innovate and create value for investors, society and the environment.

In early 2021, TransAlta entered into a long-term PPA with Pembina for the offtake of 100 MW from our proposed 130 MW Garden Plain wind project, to be located in Alberta. The project began in 2021, with a target commercial operation date in the second half of 2022. In late 2021, TransAlta entered into two long-term PPAs for the offtake of 100 per cent of the generation from its 300 MW White Rock Wind Projects located in Oklahoma. Contracting the renewable electricity and environmental attributes to an outstanding new customer with an AA credit rating from S&P Global Ratings enables TransAlta to move into the construction phase expected to begin in late 2022 with a target commercial operation date in the second half of 2023. The delivery of low-cost, reliable and clean energy from Garden Plain and White Rock supports our customers' sustainability goals and represents another step towards executing our growth plan of delivering 2 GW of capacity by 2025, which was announced in September 2021.

TransAlta is actively advancing its development pipeline, which currently consists of 800 MW in the US, up to 2 GW in Canada and 270 MW in Australia. In 2021, TransAlta acquired a 122 MW portfolio of operating solar sites located in North Carolina, which will represent a significant expansion of our solar generation. We intend to further expand our solar generation by actively pursuing solar opportunities in the US and Australian markets. The Company is also focused on pursuing hybrid integrated power solutions with customers.

We continue to invest in battery storage. In 2021, TransAlta agreed to provide renewable solar electricity supported with a battery energy storage system to the Goldfields-based operations of BHP through the construction of the Northern Goldfields Solar Project in Western Australia. The project consists of the 27 MW Mount Keith Solar Farm, 11 MW Leinster Solar Farm and 10 MW/5 MWh Leinster Battery Energy Storage System and interconnecting transmission infrastructure, all of which will be integrated into TransAlta's 169 MW Southern Cross Energy North remote network. The network and new generation will support BHP to meet its emissions reduction targets and to deliver lower carbon, sustainable nickel to its customers. The Northern Goldfields Solar Project is expected to reduce BHP's scope 2 electricity GHG emissions from its Leinster and Mount Keith operations by 540,000 tonnes of CO_2e over the first 10 years of operation. Construction of the project commenced in early 2022 and commercial operations are targeted in late 2022.

Our teams continuously explore the use of applied or new technologies such as hydrogen and CCUS to find solutions and to expand or adapt our fleet. This helps protect our shareholder value and maintain delivery of reliable and affordable electricity to our costumers. 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.

Asset Analytics and Optimization

TransAlta's Asset Analytics and Optimization ("AAO") team, formerly the Operations Diagnostic Centre, was founded in 2008. This team monitors coal-fired steam, gas-fired steam, simple-cycle, combined-cycle/cogeneration and wind-generating assets 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.

AAO 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 AAO 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. By way of 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 AAO are focused on early identification of equipment issues based on longer-term trend analysis and complements day-to-day facility operations.

The AAO team also performs production reporting functions for the coal-fired steam, gas-fired steam, simple-cycle, combined-cycle/cogeneration and wind-generating assets, and are actively engaged in projects to improve this reporting.

Data and Innovation

TransAlta created the Data and Innovation team in 2019 to modernize its data infrastructure to take advantage of new opportunities in analytics and data science. The Data and Innovation team is cross-functional, composed of data architects, data scientists, data analysts, software developers, engineers, project managers, and financial and systems analysts. The team focuses its efforts on the delivery and enhancement of TransAlta's Modern Data Architecture, the rapid delivery of data-driven applications, the design and implementation of machine learning and artificial intelligence models and the advancement of process automation through the Robotic Process Automation Centre of Excellence. In 2021, the Data and Innovation team worked with partners across the business to create new decision support tools and processes that improve our financial position and return capacity to our people. A few of the highlights from this work include:

- GenOS is a digital platform that provides near real-time performance awareness and operational decision support for our Generation fleet. By packaging the analytics and data science models of our operational data into a central platform, we are able to intuitively deliver insights to the Operations teams that drive real revenue increases and a reduction in costs. Built in-house, we have focused on onboarding our Wind and Solar fleet and have begun work with the Gas and Hydro teams.

- Industry partnership with AltaML Applied AI Lab, a groundbreaking initiative that focuses on building and expanding local talent while improving our business through the application of machine learning and artificial intelligence. The 2021 cohort worked on 11 data science use cases including building an energy market peak prediction model for our Trading team and a river flow forecasting model for our Hydro operations.

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

Our sustainability memberships include key sustainability organizations and working groups such as the EXCEL Partnership, the Canadian Business for Social Responsibility and the Canadian Electricity Association Sustainable Electricity Steering Committee, which all provide validation and support of our sustainability strategy and practices.

For additional details on governance, please 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 interface.

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 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 codes of conduct outline 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 established the AFRC, GSSC, the Human Resources Committee (the "HRC") and the 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, please refer to the Climate Change Governance in Environmental, Social and Governance ("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; and vii) 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 & Trading and Chief Financial Officer.

The Investment Committee is a Management committee chaired by our Senior Vice President, M&A, Strategy and Treasurer and is also comprised of the CEO, Executive Vice-President, Finance & Trading and Chief Financial Officer, Chief Operating Officer, and Executive Vice-President, Legal, Commercial and External Affairs. 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 & Trading and Chief Financial Officer and is comprised of 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 TSX 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 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.

Global Pandemic

We have adopted a number of risk mitigation measures in response to the COVID-19 pandemic. The Board and management is monitoring the development of the outbreak and are continually assessing its impact on the Company's operations, supply chains and customers, as well as, more generally, to the business and affairs of the Company. Potential impacts of the pandemic on the business and affairs of the Company include, but are not limited to: potential interruptions of production, supply chain disruptions, unavailability of employees at TransAlta, potential delays in growth projects, increased credit risk with counterparties and increased volatility in commodity prices and the valuations of financial instruments. In addition, the broader impacts to the global economy and financial markets could have potential adverse impacts on the availability of capital for investment and the demand for power and commodity pricing.

To manage the risks resulting from COVID-19, we continue to take a number of steps in furtherance of the Company's business continuity efforts:

Management Responses

- Regularly communicated with the Board and employees in regard to the Company's response to COVID-19;
- Maintained and updated COVID-19 safety protocols, including a back-to-office and site strategy, and a remote work strategy that will remain in place until the pandemic becomes an endemic; and
- Developed leadership plans, including contingent authorities.

Policy Changes

- We continue to align all non-essential travel and quarantine requirements with local jurisdictional guidance for all TransAlta employees and contractors for all jurisdictions in which we operate.

Employee Changes

- Provided continued assurances to employees that their employment with TransAlta would not be impacted by the COVID-19 pandemic;
- Implemented and have maintained health screening procedures, including questionnaires and temperature tests, enhanced cleaning measures and strict work protocols at the Company's offices and facilities in accordance with our back-to-office and site strategy to ensure that employees remain safe;
- Maintained policies to seamlessly allow non-essential employees to work remotely, as appropriate; and
- Provided COVID-19 related town halls and information sessions for employees featuring medical and epidemiologists.

Operational Changes

- Modified our operating procedures and implemented restrictions to non-essential access to our facilities to support continued operations through the pandemic;
- Reviewed the supply chain risk associated with all key power-generation process inputs and implemented weekly monitoring for changes in risk;
- Reached out to key supply chain contacts to determine strategies and contingencies to ensure we are able to continue to progress our growth projects, wherever possible; and
- Identified new cybersecurity risks associated with phishing emails and enhanced security protocols and increased awareness of potential threats.

Financial Oversight

- Continued to maintain a comprehensive commodity hedging program for our merchant assets that can respond to changes in underlying market conditions;
- Continued to monitor counterparties for changes in creditworthiness, as well as monitor their ability to meet obligations; and
- Continued to monitor the situation and communicate with our key lenders on any foreseeable impacts and on our response to the crisis. We maintain a strong financial position and significant liquidity with our existing committed credit facilities.

Overall, we continue to actively monitor the situation and advice from public health officials with a view to responding to changing recommendations and adapting our response and approach as necessary.

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 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 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 Monte Carlo 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, 2021, associated with our proprietary commodity risk management activities was $2 million (2020 — $1 million). Please 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.sedar.com 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 of changes in certain key variables. The analysis is based on business conditions and production volumes in 2021. 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 in order 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 (%)	Approximate impact on net earnings
Availability/production	1	$12 million

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;
- 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 2021, we had approximately 78 per cent (2020 — 90 per cent) of 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 2021, 70 per cent (2020 — 89 per cent) of our gas consumption used in generating electricity was contractually fixed or passed through to our customers and 80 per cent (2020 — 78 per cent) of our purchased coal was contractually fixed.

Actual variations in net earnings can vary from calculated sensitivities and may not be linear due to optimization opportunities, co-dependencies and cost mitigations, production, availability and other factors.

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.

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 created 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;
- Having 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 GHGs, mercury, SO2, and NOx, 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 fulfill 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 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, 2020. We had no material counterparty losses in 2021. 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, 2021:

	Investment grade *(%)*	**Non-investment grade** *(%)*	**Total** *(%)*	**Total amount**
Trade and other receivables[1,2]	89	11	100	**651**
Long-term finance lease receivables	100	—	100	**185**
Risk management assets[1]	86	14	100	**707**
Total				**1,543**

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.
(2) Includes loan receivable where the counterparties have no external credit ratings.

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 $37 million (2020 — $22 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-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 are 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
Exchange rate	$0.03	$12 million

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, 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, 2021, we have liquidity of $2.2 billion comprised of amounts not drawn under our committed credit facilities and cash on hand that is available to draw on for projects in 2022.

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 for commodity 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 for known debt issuances.

At Dec. 31, 2021, approximately 3 per cent (2020 — 7 per cent) of our total debt portfolio 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 (%)	Approximate impact on net earnings
Interest rate	30 bps	less than $1 million before tax

IBOR 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 facility references LIBOR for US-dollar drawings and the Canadian Dollar Offer Rate ("CDOR") for Canadian-dollar drawings; in addition, the non-recourse bond references the three-month CDOR. To date, no US-dollar drawings have been made on the facility and there is currently a plan to discontinue the six- and 12-month CDOR, which does not impact the facility or the non-recourse bond.

Outstanding US dollar forward starting interest rate swaps should not be affected as the three-month USD LIBOR will continue to be published until June 30, 2023. These are expected to to settle in 2022.

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:

- 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 new employees have the appropriate training and qualifications to perform their jobs.

In 2021, 33 per cent (2020 – 46 per cent) of our labour force was covered by 11 (2020 – 10) collective bargaining agreements. The increase in the number of collective agreements is the result of splitting one collective agreement into two collective agreements. The decrease in the percentage of our unionized workforce is the result of the coal-to-gas transition and subsequent retirement of Keephills Unit 1. In 2021, one (2020 – 2) agreement was renegotiated. We anticipate the successful negotiation of seven collective agreements in 2022.

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 existing transmission infrastructure in markets in which we operate continue to increase 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 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. In today's ever-evolving cybersecurity landscape, any attacks or other breaches of network or information systems may cause disruptions to our business operations. Cyberattackers may use a range of techniques, from exploiting vulnerabilities within our user-base, to using sophisticated malicious code on a single or distributed basis to try to breach our network security controls. Attackers may also use a combination of techniques in their attempt to evade safeguards that we have in place such as firewalls, intrusion prevention systems and antivirus software that exist on our network infrastructure systems. A successful cyberattack may allow for the unauthorized interception, destruction, use or dissemination of our information and may cause disruptions to our business operations.

We continuously take measures to secure our infrastructure against potential cyberattacks that may damage our infrastructure, systems and data. TransAlta's cybersecurity model consists of three pillars: technology, processes and people. Each of these pillars can be reinforced independently to address specific cyber risks and threats that are confronting TransAlta. Significant cyber risks that could pose a threat to TransAlta include phishing, ransomware, social engineering, supplier chain, commodity hostage, state sponsored, artificial intelligence, machine learning attacks and a high risk of cybersecurity employee turnover. Proactive controls and safeguards to mitigate cybersecurity risk and threats posed to the organization include:

- Leveraging technologies to restrict communication within TransAlta's networks thus limiting the ability for adversaries to achieve their aim;
- Partnering with a third-party cybersecurity specialty firm to outsource critical components of our cybersecurity program;
- Enhancing our policies and processes through the use of periodic reviews and table-top exercises;
- Maintaining an effective and robust cybersecurity awareness training and campaign;
- Integrating cybersecurity into our business processes and performing robust cybersecurity risk assessments; and
- Continuously improving our cybersecurity program to ensure it is effective in responding to and addressing cybersecurity risks.

While we have cyber insurance (as well as systems, policies, hardware, practices, data backups and procedures designed to prevent or limit the effect of the security breaches of our generation facilities and infrastructure and data), there can be no assurance that these measures will be sufficient or that such security breaches will not occur or, if they do occur, that they will be adequately addressed in a timely manner. We closely monitor both preventive and detective measures to manage these risks.

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 growth through identifying suitable acquisitions or contracted 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 is 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 (%)	Approximate impact on net earnings
Tax rate	1	$6 million

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 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. Please 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. During renewal of the insurance policies on Dec. 31, 2021, a coverage restriction was added for losses resulting from a foundation failure at the Kent Hills 1 and 2 wind facilities only. There were no other significant changes to our insurance coverage during renewal of the insurance policies on Dec. 31, 2021. 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"). For the year ended Dec. 31, 2021, the majority of our workforce supporting and executing our ICFR and DC&P worked remotely. There has been minimal impact to the design and performance of our internal controls. Management has reviewed the changes as a result of changes implemented in response to COVID-19 and is reasonably assured that adjustments to process have not materially affected, or are reasonably likely to materially affect, our ICFR or DC&P.

ICFR is a framework designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of 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.

In accordance with the provisions of NI 52-109 and consistent with U.S. Securities and Exchange Commission guidance, the scope of the evaluation did not include internal controls over financial reporting of North Carolina Solar, which the Company acquired on Nov. 5, 2021. North Carolina Solar was excluded from management's evaluation of the effectiveness of the Company's internal control over financial reporting as at Dec. 31, 2021, due to the proximity of the acquisition to year-end. Further details related to the acquisition are disclosed in Note 4 to the Company's Consolidated Financial Statements for the year ended Dec. 31, 2021. Included in the 2021 Consolidated Financial Statements of TransAlta for North Carolina Solar is 2 per cent and 5 per cent of the Company's total and net assets, respectively, as at Dec. 31, 2021.

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, 2021, 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 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 23, 2022

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") 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 control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can 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.

In accordance with the provisions of NI 52-109 and consistent with U.S. Securities and Exchange Commission guidance, the scope of the evaluation did not include internal controls over financial reporting of North Carolina Solar, which the Company acquired on Nov. 5, 2021. North Carolina Solar was excluded from management's evaluation of the effectiveness of the Company's internal control over financial reporting as at Dec. 31, 2021, due to the proximity of the acquisition to year-end. Further details related to the acquisition are disclosed in Note 4 to the Company's Consolidated Financial Statements for the year ended Dec. 31, 2021. Included in the 2021 Consolidated Financial Statements of TransAlta for North Carolina Solar is 2 per cent and 5 per cent of the Company's total and net assets, respectively, as at Dec. 31, 2021.

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.

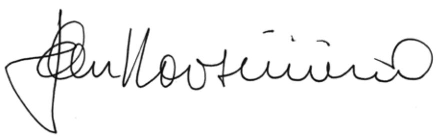
Included in the 2021 Consolidated Financial Statements of TransAlta for joint operations and equity accounted investments are 4 per cent and 10 per cent of the Company's total and net assets, respectively, as of Dec. 31, 2021, and 8 per cent of the Company's revenues for the year then ended.

Changes in Internal Controls over Financial Reporting

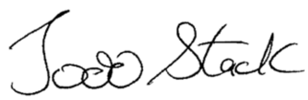
The Company's internal controls over financial reporting commencing Nov. 5, 2021, include controls designed to result in complete and accurate consolidation of North Carolina Solar's results. Other than the North Carolina Solar acquisition, there has been no change in the Company's internal control over financial reporting that occurred during the year covered by this Annual Report that has materially affected, or are 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, 2021, and has concluded that such internal control over financial reporting is effective.

Ernst & Young LLP, who has audited the consolidated financial statements of TransAlta for the year ended Dec. 31, 2021, 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 23, 2022

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, 2021, 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, 2021, 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 2021 consolidated financial statements of the Company and constituted 4% and 10% of total and net assets, respectively, as of December 31, 2021, and 8% of revenues 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.

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 North Carolina Solar, which is included in the 2021 consolidated financial statements of the Company and constituted 2% and 5% of total and net assets, respectively, as of December 31, 2021. 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 North Carolina Solar.

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, 2021 and 2020, and the related consolidated statements of earnings (loss), comprehensive earnings (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2021, and the related notes and our report dated February 23, 2022 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.

Ernst + Young LLP

Chartered Professional Accountants

Calgary, Canada
February 23, 2022

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, 2021 and 2020, the related consolidated statements of earnings (loss), comprehensive earnings (loss), changes in equity and cash flows, for each of the three years in the period ended December 31, 2021, 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, 2021 and 2020, and the financial performance and its cash flows for each of the three years in the period ended December 31, 2021, 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, 2021, 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 23, 2022 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) within the Wind and Solar segment and Goodwill related to the Wind and Solar segment

Description of the Matter	As disclosed in notes 2(G), 2(H), 2(P)(I), 7, 18 and 21 of the consolidated financial statements, the Company owns significant Wind and Solar generation assets and has recognized goodwill from historical acquisitions which must be tested for impairment at least annually or when indicators are present. The carrying value of Goodwill related to the Wind and Solar segment was $175 million and the carrying value of long-lived assets in the Wind and Solar segment consisted of property, plant & equipment of $2,304 million, right-of-use assets of $64 million and intangible assets of $147 million as at December 31, 2021. Determining the recoverable amounts for the Wind and Solar segment for the purposes of the goodwill impairment test and of certain CGUs in the Wind and Solar segment with indicators of impairment ("Wind and 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 generation profiles, commodity prices, cost estimates, 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 and Solar segment and the Wind and 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 and Solar segment and the Wind and Solar CGUs with indicators of impairment included, among others, comparing the significant assumptions used to estimate cash flows to current contracts with external parties and historical trends and obtaining historical power generation data to evaluate future generation 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 commodity prices by comparing them to externally available third-party future commodity 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), 15 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, 2021 the fair value of the Company's derivative financial instruments classified as level III was $159 million net risk management assets.

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 commodity prices, discount rates, volatility, unit availability and demand profiles, 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 valuation adjustments, and liquidity assumptions to third-party data as well as comparing terms such as volumes and timing to executed commodity contracts. We compared the unit availability and demand profile assumptions to historical information. We performed a sensitivity analysis to evaluate the assumptions that were most significant to the determination of level III fair value. For a sample of level III derivative instruments, we involved our internal valuation specialist to assist in our evaluation of the appropriateness of the discount rates by evaluating the key assumptions and methodologies.

Ernst & Young LLP

Chartered Professional Accountants
We have served as auditors of TransAlta Corporation and its predecessor entities since 1947.
Calgary, Canada
February 23, 2022

Consolidated Statements of Earnings (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars except where noted)*	**2021**	2020	2019
Revenues (Note 5)	**2,721**	2,101	2,347
Fuel and purchased power (Note 6)	**1,054**	805	881
Carbon compliance	**178**	163	205
Gross margin	**1,489**	1,133	1,261
Operations, maintenance and administration (Note 6)	**511**	472	475
Depreciation and amortization	**529**	654	590
Asset impairment charge (Note 7)	**648**	84	25
Gain on termination of Keephills 3 coal rights contract (Note 18)	**—**	—	(88)
Taxes, other than income taxes	**32**	33	29
Termination of Sundance B and C PPAs	**—**	—	(56)
Net other operating loss (income) (Note 9)	**8**	(11)	(49)
Operating income (loss)	**(239)**	(99)	335
Equity income (Note 10)	**9**	1	—
Finance lease income	**25**	7	6
Net interest expense (Note 11)	**(245)**	(238)	(179)
Foreign exchange gain (loss)	**16**	17	(15)
Gain on sale of assets and other (Note 4 and 18)	**54**	9	46
Earnings (loss) before income taxes	**(380)**	(303)	193
Income tax expense (recovery) (Note 12)	**45**	(50)	17
Net earnings (loss)	**(425)**	(253)	176
Net earnings (loss) attributable to:			
TransAlta shareholders	**(537)**	(287)	82
Non-controlling interests (Note 13)	**112**	34	94
	(425)	(253)	176
Net earnings (loss) attributable to TransAlta shareholders	**(537)**	(287)	82
Preferred share dividends (Note 28)	**39**	49	30
Net earnings (loss) attributable to common shareholders	**(576)**	(336)	52
Weighted average number of common shares outstanding in the year *(millions)*	**271**	275	283
Net earnings (loss) per share attributable to common shareholders, basic and diluted (Note 27)	**(2.13)**	(1.22)	0.18

See accompanying notes.

Consolidated Statements of Comprehensive Earnings (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2021**	2020	2019
Net earnings (loss)	**(425)**	(253)	176
Other comprehensive loss			
Net actuarial gains (loss) on defined benefit plans, net of tax[1]	**37**	(11)	(26)
Losses on derivatives designated as cash flow hedges, net of tax	**—**	(1)	—
Total items that will not be reclassified subsequently to net earnings	**37**	(12)	(26)
Losses on translating net assets of foreign operations, net of tax	**(14)**	(11)	(59)
Gains on financial instruments designated as hedges of foreign operations, net of tax	**—**	11	21
Gains (losses) on derivatives designated as cash flow hedges, net of tax[2]	**(200)**	20	61
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax[3]	**(8)**	(110)	(42)
Total items that will be reclassified subsequently to net earnings	**(222)**	(90)	(19)
Other comprehensive loss	**(185)**	(102)	(45)
Total comprehensive earnings (loss)	**(610)**	(355)	131
Total comprehensive earnings (loss) attributable to:			
TransAlta shareholders	**(693)**	(439)	54
Non-controlling interests (Note 13)	**83**	84	77
	(610)	(355)	131

(1) Net of income tax expense of $11 million for the year ended Dec. 31, 2021 (2020 — $3 million recovery, 2019 — $7 million recovery).
(2) Net of income tax recovery of $55 million for the year ended Dec. 31, 2021 (2020 —$8 million expense, 2019 — $16 million expense).
(3) Net of reclassification of income tax recovery of $2 million for the year ended Dec. 31, 2021 (2020 —$31 million recovery, 2019 — $10 million recovery).

See accompanying notes.

Consolidated Statements of Financial Position

As at Dec. 31 *(in millions of Canadian dollars)*	**2021**	2020
Cash and cash equivalents	**947**	703
Restricted cash (Note 24)	**70**	71
Trade and other receivables (Note 14)	**651**	583
Prepaid expenses	**29**	31
Risk management assets (Note 15 and 16)	**308**	171
Inventory (Note 17)	**167**	238
Assets held for sale (Note 4 and 18)	**25**	105
	2,197	1,902
Investments (Note 10)	**105**	100
Long-term portion of finance lease receivables (Note 8)	**185**	228
Risk management assets (Note 15 and 16)	**399**	521
Property, plant and equipment (Note 18)		
Cost	**13,389**	13,398
Accumulated depreciation	**(8,069)**	(7,576)
	5,320	5,822
Right-of-use assets (Note 19)	**95**	141
Intangible assets (Note 20)	**256**	313
Goodwill (Note 21)	**463**	463
Deferred income tax assets (Note 12)	**64**	51
Other assets (Note 22)	**142**	206
Total assets	**9,226**	9,747
Accounts payable and accrued liabilities	**689**	599
Current portion of decommissioning and other provisions (Note 23)	**48**	59
Risk management liabilities (Note 15 and 16)	**261**	94
Current portion of contract liabilities (Note 5)	**19**	1
Income taxes payable	**8**	18
Dividends payable (Note 27 and 28)	**62**	59
Current portion of long-term debt and lease liabilities (Note 24)	**844**	105
	1,931	935
Credit facilities, long-term debt and lease liabilities (Note 24)	**2,423**	3,256
Exchangeable securities (Note 25)	**735**	730
Decommissioning and other provisions (Note 23)	**779**	614
Deferred income tax liabilities (Note 12)	**354**	396
Risk management liabilities (Note 15 and 16)	**145**	68
Contract liabilities (Note 5)	**13**	14
Defined benefit obligation and other long-term liabilities (Note 26)	**253**	298
Equity		
Common shares (Note 27)	**2,901**	2,896
Preferred shares (Note 28)	**942**	942
Contributed surplus	**46**	38
Deficit	**(2,453)**	(1,826)
Accumulated other comprehensive income (Note 29)	**146**	302
Equity attributable to shareholders	**1,582**	2,352
Non-controlling interests (Note 13)	**1,011**	1,084
Total equity	**2,593**	3,436
Total liabilities and equity	**9,226**	9,747

Commitments and contingencies (Note 36)

On behalf of the Board:

John P. Dielwart
Director

Beverlee F. Park
Director

See accompanying notes.

Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income[1]	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2019	2,978	942	42	(1,455)	454	2,961	1,101	4,062
Net earnings (loss)	—	—	—	(287)	—	(287)	34	(253)
Other comprehensive earnings (loss):								
Net losses on derivatives designated as cash flow hedges, net of tax	—	—	—	—	(91)	(91)	—	(91)
Net actuarial losses on defined benefits plans, net of tax	—	—	—	—	(11)	(11)	—	(11)
Intercompany FVOCI investments	—	—	—	—	(50)	(50)	50	—
Total comprehensive earnings (loss)				(287)	(152)	(439)	84	(355)
Common share dividends	—	—	—	(58)	—	(58)	—	(58)
Preferred share dividends	—	—	—	(49)	—	(49)	—	(49)
Shares purchased under NCIB	(79)	—	—	18	—	(61)	—	(61)
Changes in non-controlling interests in TransAlta Renewables (Note 13)	—	—	—	5	—	5	15	20
Effect of share-based payment plans	(3)	—	(4)	—	—	(7)	—	(7)
Distributions paid, and payable, to non-controlling interests	—	—	—	—	—	—	(116)	(116)
Balance, Dec. 31, 2020	2,896	942	38	(1,826)	302	2,352	1,084	3,436
Net earnings (loss)	**—**	**—**	**—**	**(537)**	**—**	**(537)**	**112**	**(425)**
Other comprehensive earnings (loss):								
Net losses on translating net assets of foreign operations, net of hedges and tax	**—**	**—**	**—**	**—**	**(14)**	**(14)**	**—**	**(14)**
Net gains (losses) on derivatives designated as cash flow hedges, net of tax	**—**	**—**	**—**	**—**	**(208)**	**(208)**	**—**	**(208)**
Net actuarial gains on defined benefits plans, net of tax	**—**	**—**	**—**	**—**	**37**	**37**	**—**	**37**
Intercompany FVOCI investments	**—**	**—**	**—**	**—**	**29**	**29**	**(29)**	**—**
Total comprehensive earnings (loss)				**(537)**	**(156)**	**(693)**	**83**	**(610)**
Common share dividends	**—**	**—**	**—**	**(51)**	**—**	**(51)**	**—**	**(51)**
Preferred share dividends	**—**	**—**	**—**	**(39)**	**—**	**(39)**	**—**	**(39)**
Effect of share-based payment plans (Note 30)	**5**	**—**	**8**	**—**	**—**	**13**	**—**	**13**
Distributions paid, and payable, to non-controlling interests	**—**	**—**	**—**	**—**	**—**	**—**	**(156)**	**(156)**
Balance, Dec. 31, 2021	**2,901**	**942**	**46**	**(2,453)**	**146**	**1,582**	**1,011**	**2,593**

(1) Refer to Note 29 for details on components of, and changes in, accumulated other comprehensive earnings (loss).
See accompanying notes.

Consolidated Statements of Cash Flows

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2021**	2020	2019
Operating activities			
Net earnings (loss)	**(425)**	(253)	176
Depreciation and amortization (Note 18 and 37)	**719**	798	709
Net gain on sale of assets	**(54)**	(9)	(45)
Accretion of provisions (Note 23)	**32**	30	23
Decommissioning and restoration costs settled (Note 23)	**(18)**	(18)	(34)
Deferred income tax recovery (Note 12)	**(11)**	(85)	(18)
Unrealized (gain) loss from risk management activities	**(34)**	42	(32)
Unrealized foreign exchange (gain) loss	**(24)**	1	13
Provisions	**(41)**	9	13
Asset impairment (Note 7)	**648**	84	25
Equity income, net of distributions from investments (Note 10)	**(5)**	(1)	—
Other non-cash items	**40**	15	(102)
Cash flow from operations before changes in working capital	**827**	613	728
Change in non-cash operating working capital balances (Note 33)	**174**	89	121
Cash flow from operating activities	**1,001**	702	849
Investing activities			
Additions to property, plant and equipment (Note 18 and 37)	**(480)**	(486)	(417)
Additions to intangible assets (Note 20 and 37)	**(9)**	(14)	(14)
Restricted cash (Note 24)	**(1)**	(39)	34
Loan receivable (Note 22)	**(3)**	(5)	(10)
Acquisitions, net of cash acquired (Note 4)	**(120)**	(32)	(117)
Acquisition of investments (Note 10)	**—**	(102)	—
Investment in the Pioneer Pipeline	**—**	—	(83)
Proceeds on sale of Pioneer Pipeline (Note 4)	**128**	—	—
Proceeds on sale of property, plant and equipment	**39**	6	13
Realized gains (losses) on financial instruments	**(6)**	2	3
Decrease in finance lease receivable	**41**	17	24
Other	**(16)**	(12)	23
Change in non-cash investing working capital balances	**(45)**	(22)	32
Cash flow used in investing activities	**(472)**	(687)	(512)
Financing activities			
Net decrease in borrowings under credit facilities (Note 24 and 33)	**(114)**	(106)	(119)
Repayment of long-term debt (Note 24 and 33)	**(92)**	(489)	(96)
Issuance of long-term debt (Note 24)	**173**	753	166
Issuance of exchangeable securities (Note 25)	**—**	400	350
Dividends paid on common shares (Note 27)	**(48)**	(47)	(45)
Dividends paid on preferred shares (Note 28)	**(39)**	(39)	(40)
Repurchase of common shares under NCIB (Note 27)	**(4)**	(57)	(68)
Proceeds on issuance of common shares	**8**	—	—
Realized gains on financial instruments	**3**	3	—
Distributions paid to subsidiaries' non-controlling interests (Note 13)	**(156)**	(97)	(106)
Decrease in lease liabilities (Note 24 and 33)	**(8)**	(25)	(21)
Financing fees and other	**(4)**	(11)	(35)
Change in non-cash financing working capital balances	**(1)**	(13)	—
Cash flow from (used in) financing activities	**(282)**	272	(14)
Cash flow from operating, investing, and financing activities	**247**	287	323
Effect of translation on foreign currency cash	**(3)**	5	(1)
Increase in cash and cash equivalents	**244**	292	322
Cash and cash equivalents, beginning of year	**703**	411	89
Cash and cash equivalents, end of year	**947**	703	411
Cash taxes paid	**57**	36	35
Cash interest paid	**220**	201	185

See accompanying notes.

Notes to 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. Its head office is located in Calgary, Alberta.

I. Generation Segments

During the fourth quarter of 2021, the Company realigned its current operating segments to better reflect a change in how TransAlta's President and Chief Executive Officer (the chief operating decision maker) ("CODM") reviews financial information in order to allocate resources and assess performance. The primary changes are the elimination of the Alberta Thermal and the Centralia segments, and the reorganization of the North American Gas and Australia Gas segments into a new "Gas" segment. The Alberta Thermal facilities that have been converted to gas have been included in the Gas segment. The remaining assets previously included in Alberta Thermal, including the mining assets and those facilities not converted to gas and the remaining Centralia unit, are included in a new "Energy Transition" segment. No changes were made to the Hydro and Wind and Solar segments. This change better aligns with the Company's long-term strategy and reflects its Clean Electricity Growth Plan.

The four generation segments of the Company are as follows: Hydro, Wind and Solar, Gas, and Energy Transition. Previously, the six generation segments were as follows: Hydro, Wind and Solar, North American Gas, Australian Gas, Alberta Thermal, and Centralia. The Company directly or indirectly owns and operates hydro, wind and solar, natural-gas-fired and coal-fired facilities, related mining operations and natural gas pipeline operations in Canada, the United States ("US") and Australia. The Wind and Solar segment includes the financial results, on a proportionate basis, of our investment in SP Skookumchuck Investment, LLC. Revenues are derived from the availability and production of electricity and steam as well as ancillary services.

Comparative segmented results for 2020 and 2019 have been restated to align with the 2021 operating segments.

II. Energy Marketing Segment

The Energy Marketing segment derives revenue and earnings from the wholesale trading of electricity and other energy-related commodities and derivatives. No change was made to the Energy Marketing segment.

Energy Marketing manages available generating capacity as well as the fuel and transmission needs of the generation segments by utilizing contracts of various durations for the forward sales of electricity and for the purchase of natural gas and transmission capacity. Energy Marketing is also responsible for recommending portfolio optimization decisions. The results of these optimization activities are included in each generation segment.

III. Corporate and Other Segment

The Corporate and Other 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. Since 2020, the Corporate and Other segment also includes the investment in EMG International, LLC ("EMG"), a wastewater treatment processing company.

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. 23, 2022.

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 the accounting policies disclosed in accordance with the amendments to IAS 1 to disclose the material accounting policy information rather than significant 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. Revenue is measured based on the transaction price specified in a contract with a customer. Revenue is recognized when control of the good or services is 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 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, 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 (i.e., 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 (i.e., 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 (i.e., 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 Canadian and US coal operations, and the sale of coal to third parties. 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) are comprised of 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 ("PPA"). Contracts for differences is a financial contract whereby the Company receives a fixed price per MWh and pays the prevailing real-time energy market price per MWh. A virtual PPA is where the Company receives the difference between the fixed contract price per MWh and the settled market price. These arrangements are option-based derivatives 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 ("FVOCI").

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 FVOCI 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. 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 financings will be classified as a 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 earnings ("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 earnings ("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 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 are comprised of cash and highly liquid investments with original maturities of three months or less.

D. Inventory
I. Fuel
The Company's inventory balance is comprised 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 internally produced coal inventory is determined using absorption costing, which is defined as the sum of all applicable expenditures and charges directly incurred in bringing inventory to its existing condition and location. Available coal inventory tends to increase during the second and third quarters as a result of favourable weather conditions and lower electricity production as maintenance is performed. Due to the limited number of processing steps incurred in mining coal and preparing it for consumption and its relatively low value on a per-unit basis, management does not distinguish between work in process and coal available for consumption. 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, 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 using the best estimate of the amount required by the Company to settle its obligation in excess of government-established caps and targets. To the extent compliance costs are recoverable under the terms of contracts with third parties, the amounts are recognized as revenue in the period of recovery.

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 assets 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. Capital 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. Other 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	2-51 years
Wind generation	2-30 years
Gas generation	2-36 years
Energy Transition	2-16 years
Capital spares and other	2-51 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 comprised 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 and fuel and purchased power 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	2-7 years
Power sale contracts	1-19 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 flows 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 re-assessed at each reporting date and are recognised 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 pro-rated 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. The accretion of the net present value discount is charged to net earnings each period and is included in net interest expense. 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. Decommissioning and restoration obligations for coal mines are incurred over time as new areas are mined, and a portion of the provision is settled over time as areas are reclaimed prior to final pit reclamation. Reclamation costs for mining assets are recognized on a unit-of-production basis.

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 is 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.

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.

Lessor
PPAs and other long-term contracts may contain, or may be considered, leases where the fulfillment 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.

When the Company has subleased all or a portion of an asset it is leasing and for which it remains the primary obligor under the lease, it accounts for the head lease and the sublease as two separate contracts. The sublease is classified as a finance lease by reference to the right-of-use asset arising from the head lease.

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 earnings is attributed to the non-controlling interests even if this results in the non-controlling interests having a negative balance.

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, which can range from 30 to 60 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 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 regards 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 2019 to 2021 is found 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.

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. See Note 12 for further details on the impacts of the Company’s tax policies.

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. These fair value levels are outlined and discussed in more detail in Note 15. 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 fulfiled.

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, in determining the amount to be capitalized. 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) and Note 23. 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 in respect of decommissioning and restoration provisions can be found in Notes 7 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. See Note 31 for disclosures on employee future benefits.

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 9 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, 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.

XI. Classification of Joint Arrangements

Upon entering into a joint arrangement, the Company must classify it as either a joint operation or joint venture, which 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 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.

XIII. Change in Estimates

During the year ended Dec. 31, 2021, there were changes in estimates relating to defined benefit obligations and decommissioning and other provisions. Refer to Note 23 and 26 for further details. During the year ended Dec. 31, 2020, there were changes in estimates relating to the useful life of PP&E. Refer to Note 18 for further details.

3. Accounting Changes

A. Current Accounting Changes

I. Amendments to IAS 1 Presentation of Financial Statements: Material Accounting Policies

Effective for the 2021 annual financial statements, the Company early adopted amendments to IAS 1 *Presentation of Financial Statements* in advance of its mandatory effective date of Jan. 1, 2023, which requires entities to disclose their material accounting policy information rather than their significant accounting policies. The Company has updated the accounting policies disclosed in Note 2 based on its assessment of the amended standard.

II. Amendments to IAS 16 Property, Plant and Equipment: Proceeds before Intended Use

Effective Jan. 1, 2021, the Company early adopted amendments to IAS 16 *Property, plant and equipment* ("IAS 16 Amendments") in advance of its mandatory effective date of Jan. 1, 2022. The Company adopted the IAS 16 Amendments retroactively. No cumulative effect of initially applying the guidance arose. The IAS 16 Amendments prohibit deducting from the cost of an item of property, plant and equipment any proceeds from selling items produced while bringing that asset to the location and condition necessary for it to be capable of operating in a manner intended by management. Instead, an entity recognizes the proceeds from selling such items, and the cost of producing those items, in profit or loss. No adjustments resulted from early adopting the amendments.

III. IFRS 7 Financial Instruments: Disclosures — Interest Rate Benchmark Reform

The transition of the London Interbank Offered Rates ("LIBOR") has begun with the cessation of the publication of one-week and two-month USD LIBOR occurring on Dec. 31, 2021. The remaining overnight, one-, three-, six-, and 12-month USD LIBOR will continue to be published until their cessation date on June 30, 2023. Existing financial instruments may continue to use USD LIBOR while they are published until they mature, however, new financial instruments will not be using USD LIBOR if entered into after Dec. 31, 2021. The IASB issued Interest Rate Benchmark Reform — Phase 2 in August 2020, which amends IFRS 9 *Financial Instruments*, IAS 39 *Financial instruments: Recognition and Measurement*, IFRS 7 *Financial Instruments: Disclosures* and IFRS 16 *Leases*. The amendments were effective Jan. 1, 2021, and were adopted by the Company on Jan. 1, 2021. There was no financial impact upon adoption.

The Company's credit facilities references USD LIBOR for US-dollar drawings and the Canadian Dollar Offered Rate for Canadian drawings, and includes appropriate fallback language to replace these benchmark rates if a benchmark transition event were to occur. For the year ended Dec. 31, 2021, there were no drawings under the credit facilities. The Company has interest rate swap agreements in place with a notional amount of US$150 million referencing three-month LIBOR, expected to settle in the third quarter of 2022.

B. Future Accounting Changes

I. Amendments to IAS 37 Provisions, Contingent Liabilities and Contingent Assets

On May 14, 2020, the IASB issued *Onerous Contracts — Cost of Fulfilling a Contract* and amendments to IAS 37 *Provisions, Contingent Liabilities and Contingent Assets* to specify which costs to include when assessing whether a contract will be loss-making. The amendments are effective for annual periods beginning on or after Jan. 1, 2022, and will be adopted by the Company in 2022. The amendments are effective for contracts for which an entity has not yet fulfilled all its obligations on or after the effective date. No financial impact is expected upon adoption.

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

On May 7, 2021, the IASB issued amendments to IAS 12 *Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction*. 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, with early application permitted. The Company's current position aligns with the amendment and no financial impact is therefore expected upon adoption on the effective date.

III. Amendments to IAS 1 Classification of Liabilities as Current or Non-Current

In January 2020, the IASB issued amendments to IAS 1 *Presentation of Financial Statements*, to provide a more general approach to the presentation of liabilities as current or non-current based on contractual arrangements in place at the reporting date. These amendments specify that the 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, provide that management's expectations are not a relevant consideration as to whether the Company will exercise its rights to defer settlement of a liability and clarify when a liability is considered settled.

The amendments are effective for annual periods beginning on or after Jan. 1, 2023, and are to be applied retrospectively. The Company has not yet determined the impact of these amendments on its consolidated financial statements.

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 and Divestitures

In accordance with IFRS 3 *Business Combinations*, the substance of the transactions described below constituted a business combination for TransAlta. The fair values of the identifiable assets and liabilities of the acquired entity in the business combinations as at the date of acquisition were:

	North Carolina Solar (A) Nov. 5, 2021	Ada facility (B) May 19, 2020
Assets		
Cash and cash equivalents	4	1
Accounts receivable	4	3
Property, plant and equipment	146	1
Intangible assets(1)	—	37
Right of use assets	13	—
Inventory	—	1
Prepaid expenses	—	1
Liabilities		
Accounts payable and accrued liabilities	(4)	—
Lease liabilities	(13)	—
Tax equity liability	(20)	—
Deferred taxes	(3)	—
Risk management liabilities (current and long-term)	—	(5)
Decommissioning provisions	(4)	(1)
Net assets acquired	**123**	38
Cash consideration	**120**	32
Working capital consideration	**3**	6
Total purchase consideration transferred	**123**	38

1) This relates to the power sales contract acquired and is being amortized over six years.

A. Acquisition of North Carolina Solar

On Nov. 5, 2021, the Company closed the acquisition of a 100 per cent membership interest in CI-II Mitchell Holding LLC, owner of a 122 MW portfolio of operating solar sites located in North Carolina (collectively, "North Carolina Solar"), for cash consideration of US$99 million (including working capital adjustments) and the assumption of existing tax equity obligations. The acquisition was funded using existing liquidity. The North Carolina Solar facility consists of 20 solar photovoltaic sites across North Carolina. The sites were commissioned between November 2019 and May 2021 and are all operational. The facility is secured by long-term PPAs with Duke Energy, which have an average remaining term of 12 years. Under the PPAs, Duke Energy receives the renewable electricity, capacity and environmental attributes from each facility.

Certain assets and liabilities have been measured on a provisional basis. If new facts and circumstances are obtained within one year from the date of acquisition that existed at the date of acquisition, any identified adjustments to the above amounts or additional provisions that existed at the date of acquisition, may result in a revision to the accounting for the acquisition.

Had North Carolina Solar been acquired at the beginning of the year, the assets would have contributed an estimated $16 million to revenues and $9 million to net earnings before taxes.

At the closing of the acquisition, TransAlta Renewables Inc. ("TransAlta Renewables"), a subsidiary of the Company, acquired a 100 per cent economic interest in North Carolina Solar from a wholly owned subsidiary of the Company through a tracking preferred share structure for aggregate consideration of approximately US$102 million.

B. Acquisition of the Ada Facility

On May 19, 2020, the Company closed the acquisition of a contracted natural-gas-fired cogeneration facility from two private companies for a purchase price of US$27 million. The Ada facility is a 29 MW cogeneration facility in Michigan that is contracted under a PPA and a steam sale agreement for approximately 6 years with Consumers Energy and Amway.

C. Sale of Pioneer Pipeline

On June 30, 2021, the Company closed the sale of the Pioneer Pipeline to ATCO Gas and Pipelines Ltd. ("ATCO") for the aggregate sale price of $255 million. The net cash proceeds to TransAlta from the sale of its 50 per cent interest was approximately $128 million, subject to certain adjustments.

As a result of this sale, the Company has derecognized the related Pioneer Pipeline assets that were classified as assets held for sale of $97 million and recognized a gain on sale of $31 million on the statement of earnings. In addition, as part of the transaction, the natural gas transportation agreement with the Pioneer Pipeline Limited Partnership was terminated, which resulted in the derecognition of the right-of-use asset of $41 million and a lease liability of $43 million related to the pipeline, resulting in a gain of $2 million.

5. Revenue

A. Disaggregation of Revenue

The majority of the Company's revenues are derived from the sale of physical 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, 2021	Hydro	Wind and Solar	Gas(1)	Energy Transition(2)	Energy Marketing	Corporate and Other	Total
Revenues from contracts with customers							
Power and other(3)	28	207	395	24	—	—	654
Environmental attributes	—	28	—	—	—	—	28
Revenue from contracts with customers	28	235	395	24	—	—	682
Revenue from leases(4)	—	—	19	—	—	—	19
Revenue from derivatives and other trading activities	—	(25)	(118)	138	211	4	210
Merchant revenue and other(3)(5)	355	95	813	547	—	—	1,810
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) This segment includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal. Refer to Note 1 for further details.
(2) This segment includes the segment previously known as Centralia and the facilities not converted to gas previously in the Alberta Thermal. Refer to Note 1 for further details.
(3) The Alberta PPAs for certain facilities included in the Hydro, Gas and Energy Transition segments with the Balancing Pool expired at Dec. 31, 2020. These facilities began operating on a merchant basis in the Alberta market on Jan. 1, 2021.
(4) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases.
(5) Includes merchant revenue, government incentives and other miscellaneous.

Year ended Dec. 31, 2020	Hydro	Wind and Solar	Gas[1]	Energy Transition[2]	Energy Marketing	Corporate and Other	Total
Revenues from contracts with customers							
Power and other	141	238	465	156	—	—	1,000
Environmental attributes	—	23	—	—	—	—	23
Revenue from contracts with customers	141	261	465	156	—	—	1,023
Revenue from leases[3]	—	—	123	—	—	—	123
Revenue from derivatives and other trading activities	—	(2)	(8)	283	122	12	407
Merchant revenue and other[4]	11	70	207	265	—	(5)	548
Total revenue	152	329	787	704	122	7	2,101
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	—	25	7	26	—	—	58
Over time	141	236	458	130	—	—	965
Total revenue from contracts with customers	141	261	465	156	—	—	1,023

(1) This segment includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal. Refer to Note 1 for further details.
(2) This segment includes the segment previously known as Centralia and the facilities not converted to gas previously in the Alberta Thermal. Refer to Note 1 for further details.
(3) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases.
(4) Includes merchant revenue, government incentives and other miscellaneous.

Year ended Dec. 31, 2019	Hydro	Wind and Solar	Gas[1]	Energy Transition[2]	Energy Marketing	Corporate and Other	Total
Revenues from contracts with customers							
Power and other	142	221	497	185	—	—	1,045
Environmental attributes	—	23	—	—	—	—	23
Revenue from contracts with customers	142	244	497	185	—	—	1,068
Revenue from leases[3]	—	—	130	—	—	—	130
Revenue from derivatives and other trading activities	—	18	(15)	160	129	4	296
Merchant revenue and other[4]	14	50	239	560	—	(10)	853
Total revenue	156	312	851	905	129	(6)	2,347
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	—	27	5	46	—	—	78
Over time	142	217	492	139	—	—	990
Total revenue from contracts with customers	142	244	497	185	—	—	1,068

(1) This segment includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal. Refer to Note 1 for further details.
(2) This segment includes the segment previously known as Centralia and the facilities not converted to gas previously in the Alberta Thermal. Refer to Note 1 for further details.
(3) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases.
(4) Includes merchant revenue, government incentives and other miscellaneous.

B. Contract Liabilities

The Company has recognized the following revenue-related contract liabilities:

Contract liabilities	**2021**	2020
Balance, beginning of the year	**15**	15
Amounts transferred to revenue included in opening balance	**(1)**	(1)
Consideration received	**8**	1
Increases due to amounts billed to customers	**—**	2
Changes in transaction price	**11**	—
Performance obligations satisfied	**(1)**	(2)
Balance, end of year	**32**	15
Current portion	**19**	1
Long-term portion	**13**	14

The contract liabilities outstanding at Dec. 31, 2021, and Dec. 31, 2020, primarily relate to prepayments relating to the Company's New Richmond and Bone Creek facilities where the Company still has to fulfil its performance obligations. In addition, the Company recognized a provision for liquidated damages due to the Sarnia outages that occurred in the second quarter of 2021.

C. Remaining Performance Obligations

The following disclosures regarding the aggregate amounts of transaction prices allocated to remaining performance obligations (contract revenues that have not yet been recognized) for contracts in place at the end of the reporting period exclude revenues related to contracts that qualify for the invoice practical expedient and contracts with an original expected duration of less than 12 months.

Additionally, 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. Future revenues that are related to constrained variable consideration are not included in the disclosure of remaining performance obligations until the constraints are resolved.

Contracts with customers that are accounted for as derivatives are excluded from these disclosures. Refer to Note 15 for further details. Contracts that have been executed for development projects are excluded until commercial operations have been achieved.

As a result, the amounts of future revenues disclosed below represent only a portion of future revenues that are expected to be realized by the Company from its contractual portfolio.

Hydro

At Dec. 31, 2020, the Company's PPA with the Balancing Pool to provide the capacity of 12 hydro facilities throughout the province of Alberta concluded. Commencing Jan. 1, 2021, production has been sold into the Alberta merchant market.

The Company has contracts for services at specific hydro facilities, which will conclude at the end of 2030. The Company also has a contract with the Government of Alberta to manage water for flood and drought mitigation purposes, which concludes in 2026. Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2021, are approximately $46 million.

Wind and Solar

At Dec. 31, 2021, the Company had long-term contracts with customers to deliver electricity and the associated renewable energy credits from three wind facilities located in Alberta, Minnesota and Quebec, for which the invoice practical expedient is not applied. The PPAs generally require all available generation to be provided to customers at fixed prices, with certain pricing subject to annual escalations for inflation. The Company expects to recognize such amounts as revenue as it delivers electricity over the remaining terms of the contracts, until 2024, 2034 and 2033, respectively. The variable revenues under the contracts are considered to be fully constrained. Accordingly, these revenues are excluded from these disclosures.

The Company also has contracts to sell renewable energy certificates generated at merchant wind facilities and expects to recognize revenues as it delivers the renewable energy certificates to the purchasers over the remaining terms of the contracts, from 2022 through 2024. Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2021, are approximately $9 million.

Gas

At Dec. 31, 2020, the Company's PPAs with the Balancing Pool for capacity and electricity from the Keephills Unit 2 and Sheerness Units 1 and 2 legacy coal facilities concluded. Future production has been sold into the merchant market.

At Dec. 31, 2021, the Company has contracts with customers to deliver energy services from one of its gas facilities in Ontario. The contracts all consist of a single performance obligation requiring the Company to stand ready to deliver electricity and steam. On May 12, 2021, the Company executed an Amended and Restated Energy Supply Agreement with one of its large industrial customers at the Sarnia cogeneration facility that provides for the supply of electricity and steam. This agreement will extend the term of the original agreement from Dec. 31, 2022 to Dec. 31, 2032. However, if TransAlta is unable to enter into a new contract with the Ontario Independent Electricity System Operator or enter into agreements with its other industrial customers at the Sarnia cogeneration facility that extend past Dec. 31, 2025, then the Company has the option to provide notice of termination in 2022 that would terminate the Amended and Restated Energy Supply Agreement four years following such notice. The Company currently expects to recognize revenue as it delivers electricity and steam to the other industrial customers at the Sarnia cogeneration facility until the completion of the contracts in late 2025, or 2032, if the contract is extended.

At the same gas facility, the Company has a contract with the local power authority with fixed capacity charges that are adjusted for seasonal fluctuations, steam demand from the plant's other customers and for deemed net revenue related to production of electricity into the market. As a result, revenues recognized in the future will vary as they are dependent upon factors outside of the Company's control and are considered to be fully constrained. Accordingly, these revenues are excluded from these disclosures. The Company expects to recognize such revenue as it stands ready to deliver electricity until the completion of the contract term on Dec. 31, 2025.

At Dec. 31, 2021, the Company had contracts with customers to deliver steam, hot water and chilled water from one of its other gas facilities in Ontario, extending through 2023 and 2033. Prices under these contracts include fixed annual fees, variable thermal energy charges based on gas prices, and fixed base amounts per gigajoule, subject to escalation annually for both gas prices and inflation. One contract includes minimum annual take-or-pay volumes. Estimated future revenues related to the remaining performance obligations for this contract as of Dec. 31, 2021, are approximately $31 million.

The Company has a contract with its customer for provision of steam and electricity output at its Alberta cogeneration facility extending through to Dec. 31, 2029. The contract is considered an operating lease resulting in some revenues being classified for accounting purposes as variable lease revenues. Other revenue streams are based on cost-recovery mechanisms and are variable in nature and considered to be fully constrained and are these revenues are excluded from these disclosures.

The Company has a contract, commencing in late 2023, for the sale of capacity and electricity, exercisable at the option of the customer in Canada, under which the Company will receive a fixed capacity payment and variable energy payments based on production. Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2021, are approximately $336 million, of which the Company expects to recognize on average, between $5 million to $10 million in 2023 and $40 million to $45 million annually thereafter for the duration of the contracts.

At Dec. 31, 2021, the Company has PPAs with customers to deliver electricity from its gas facilities located in Australia. The PPAs generally call for all available generation to be provided to customers. Pricing terms include fixed and variable price components for delivered electricity and fixed capacity payments. The variable revenues under the contracts are considered to be fully constrained and are excluded from these disclosures. Another one of the Company's PPA to deliver electricity from its gas facilities is considered a finance lease resulting in some revenues being classified for accounting purposes as finance lease income and are excluded from these disclosures. The Company also earns revenues from providing operation and maintenance services for the facility for a fixed monthly fee. Estimated future revenues related to the remaining performance obligations for these contracts as at Dec. 31, 2021, are approximately $2.5 billion, of which the Company expects to recognize approximately $285 million in total over the next two fiscal years and on average, between approximately $85 million to $145 million annually thereafter for the duration of the remaining contract.

Energy Transition

At Dec. 31, 2020, the Company's PPAs with the Balancing Pool for capacity and electricity from the Keephills Unit 1 coal facility concluded. Commencing Jan. 1, 2021, production has been sold into the merchant market.

6. Expenses by Nature

Fuel and purchased power and operations, maintenance and administrative ("OM&A") expenses classified by nature are as follows:

Year ended Dec. 31	**2021**		2020		2019	
	Fuel and purchased power	**OM&A**	Fuel and purchased power	OM&A	Fuel and purchased power	OM&A
Gas fuel costs[1]	**306**	**—**	159	—	133	—
Coal fuel costs[1][2]	**164**	**—**	269	—	310	—
Royalty, land lease, other direct costs	**19**	**—**	20	—	21	—
Purchased power	**339**	**—**	163	—	246	—
Mine depreciation[3]	**190**	**—**	144	—	119	—
Salaries and benefits	**36**	**234**	50	235	52	228
Other operating expenses[4]	**—**	**277**	—	237	—	247
Total	**1,054**	**511**	805	472	881	475

(1) During 2021, fuel costs have been split to show natural gas and coal fuel costs separately within the above table and carbon compliance costs have been reclassified from fuel and purchased power to a separate line called carbon compliance costs on the Consolidated Statements of Earnings (Loss). Prior periods have been adjusted to reflect these reclassifications.

(2) Included in coal fuel costs for 2021 was $17 million related to the impairment of coal inventory recorded during 2021 (2020 — $15 million). Refer to Note 17 for further details.

(3) Included in mine depreciation for 2021 was $48 million related to the mine depreciation that was initially recorded in the standard cost of coal inventory and then subsequently impaired during 2021 (2020 — $22 million) . Refer to Note 17 for further details.

(4) 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. Refer to Note 17 for further details.

7. Asset Impairment

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 for each CGU by calculating an approximate fair value less costs of disposal using discounted cash flow projections based on the Company's long-range forecasts. The valuations used are subject to measurement uncertainty based on assumptions and inputs to the Company's long-range forecast, including changes to fuel costs, operating costs, capital expenditures, external power prices and useful lives of the assets extending to the last planned asset retirement in 2072.

	2021	2020	2019
PP&E Impairments:			
Energy Transition facilities and projects (reversals)	**345**	79	(151)
Energy Transition - Centralia mine decommissioning and restoration provision	**—**	3	141
Changes in decommissioning and restoration provisions for retired assets[1]	**32**	—	2
Highvale mine	**195**	—	—
Kaybob Cogeneration Project	**27**	—	—
Wind	**12**	—	—
Hydro	**5**	2	—
Gas	**5**	—	—
Intangible asset impairment - coal rights[2]	**17**	—	—
Assets held for sale[3]	**—**	—	15
Project development costs[4]	**10**	—	18
Asset impairment	**648**	84	25

(1) Changes related to changes in discount rates on retired assets.
(2) Impaired to nil as no future coal will be extracted from this area of the mine.
(3) 2019 amounts relate to trucks and associated inventory to be sold within the Energy Transition segment and accordingly, these items were impaired to net realizable value.
(4) During 2021, the Company recorded an impairment of $9 million in the Hydro segment for the balance of project development costs at one of our hydro facilities as there is uncertainty on timing of when the project will proceed and $1 million related to projects that are no longer proceeding. During 2020, the Company wrote off nil (2019 — $18 million) in project development costs related to projects that are no longer proceeding within the Corporate segment.

A. Energy Transition Asset Impairments

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), 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 equipment for 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, of which $25 million was related to assets held for sale. Discounting did not have a material impact to 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 2020, the Company recognized an impairment on Sundance Unit 3 in the amount of $70 million due to the Company's decision to retire the unit. As there were no estimated future cash flows from power generation expected to be derived from the unit, the unit was removed from the Alberta merchant CGU and immediately written down to the salvage value of the scrap materials. In addition, the Company recognized an impairment of $9 million (US$7 million) due to a decrease in the fair value of land for the Centralia mine determined through a third-party appraiser.

In 2019, an internal valuation indicated the fair value less costs of disposal of the Centralia thermal facility CGU exceeded the carrying value, resulting in a recoverability test in 2019. The updated fair value included sustained changes in the market power price and cost of coal due to contract renegotiation. As a result of the recoverability test, an impairment reversal of $151 million was recorded in the Centralia segment.

B. Highvale Mine

During 2021, with the expected closure of the Highvale mine at the end of 2021, it was determined that the estimated salvage value exceeded the economic benefit to the Alberta Merchant CGU. The asset has been 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.

C. Kaybob Cogeneration Project

On Oct. 1, 2019, TransAlta and Energy Transfer Canada ("ET Canada" formerly known as SemCAMS Midstream ULC) entered into definitive agreements to develop, construct and operate a 40 MW cogeneration facility at the Kaybob South No. 3 sour gas processing plant. The facility was expected to receive its final regulatory approvals in the second half of 2020 and begin construction in December 2020. On Sept. 25, 2020, the Alberta Utilities Commission ("AUC") released a decision in which it approved the construction and operation of the facility, but denied the application for the Industrial System Designation. TransAlta will not be proceeding with the Kaybob cogeneration facility as a result of ET Canada's purported termination of the agreements to develop, construct and operate the 40 MW cogeneration facility at the Kaybob South No. 3 sour gas processing plant. As a result, the Company recorded an impairment 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. TransAlta has commenced an arbitration seeking compensation for ET Canada's wrongful termination of the agreements. Refer to Note 36 for further details.

D. Wind Facilities

During the third quarter of 2021, the Company recorded an impairment of $10 million for a wind asset as result of an increase in estimated decommissioning costs after the review of a recent engineering study on the decommissioning costs of the wind sites. Refer to Note 23 for more details for changes in decommissioning and restoration provisions. The resulting fair value measurement less cost of disposal is categorized as a Level III fair value measurement and the Company has adjusted the expected value down to $65 million using discount rates of 5.0 per cent (Dec. 31, 2020 — 5.3 per cent). The key assumptions impacting the determination of fair value are electricity production, sales prices and cost inputs, which are subject to measurement uncertainty.

During 2021, the Company recognized an impairment 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. Refer to Note 24 for further details.

E. Impairment on Decommissioning and Restoration Provision on Retired Assets

During 2019, the Company adjusted the Centralia mine decommissioning and restoration provision as management no longer believed that the fine coal recovery and reclamation work will occur as originally proposed. At the end of 2019, the Company's best estimate of the decommissioning and restoration provision increased by $141 million. Since the Centralia mine is no longer operating and reached the end of its useful life in 2006, this adjustment resulted in the immediate recognition of the full $141 million, through asset impairment charges to net earnings.

8. Finance Lease Receivables

Amounts receivable under the Company's finance leases associated with the Poplar Creek cogeneration facility and the Southern Cross Energy facilities are as follows:

As at Dec. 31	2021		2020	
	Minimum lease receipts	**Present value of minimum lease receipts**	Minimum lease receipts	Present value of minimum lease receipts
Within one year	**58**	**54**	63	56
Second to fifth years inclusive	**127**	**105**	169	126
More than five years	**80**	**66**	100	82
	265	**225**	332	264
Less: unearned finance lease income	**40**	**—**	68	—
Total finance lease receivables	**225**	**225**	264	264

	2021	2020
Included in the Consolidated Statements of Financial Position as:		
Current portion of finance lease receivables (Note 14)	**40**	36
Long-term portion of finance lease receivables	**185**	228
Total finance lease receivables	**225**	264

On Oct. 22, 2020, Southern Cross Energy ("SCE"), a subsidiary of the Company, replaced and extended its current long-term PPA with BHP Billiton Nickel West Pty Ltd. ("BHP"). The new agreement was effective Dec. 1, 2020, and replaces the previous contract that was scheduled to expire Dec. 31, 2023. The amendment to the PPA extends the term to Dec. 31, 2038, and provides SCE with the exclusive right to supply thermal and electrical energy from the Southern Cross Facilities for BHP's mining operations located in the Goldfields region of Western Australia. For accounting purposes, the original agreement was accounted for as an operating lease. Under the new PPA, the agreement is now accounted for as a finance lease.

As a result, in 2020, the Company derecognized net assets of $77 million, which included balances for PP&E, intangible assets, deferred credits and prepaid expenses. In addition, the Company recognized a finance lease receivable of $89 million and a gain on asset disposition of $12 million. Subsequent to the transaction, the Company incurred additional major maintenance costs in relation to these assets which was recorded as a reduction to the gain on asset disposition.

9. Net Other Operating Expense (Income)

Net other operating income includes the following:

Year ended Dec. 31	2021	2020	2019
Alberta Off-Coal Agreement	**(40)**	(40)	(40)
Supplier settlements	**34**	—	—
Onerous contract provisions	**14**	29	—
Insurance recoveries and other[1]	**—**	—	(9)
Net other operating expense (income)	**8**	(11)	(49)

(1) There were no insurance recoveries in 2021 or 2020. In 2019, the Company received $10 million in insurance recoveries related to insurance proceeds for tower fires at Wyoming and Summerview.

A. 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. In July 2018, the Company obtained financing against the OCA payments. Refer to Note 24 for further details.

B. Supplier Settlements

During 2021, $34 million was expensed relating to decisions to no longer proceed with 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.

C. 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.

During 2020, an onerous contract provision of $29 million was recognized as a result of a decision to accelerate plans to eliminate coal as a fuel source by the end of 2021 at the Sheerness facility. The last coal shipment was received during the first quarter of 2021, while the payments under the coal supply agreement will continue until 2025.

10. Investments

The Company's investments in joint ventures and associates that are accounted for using the equity method consist of its investments in Skookumchuck and EMG.

The change in investments is as follows:

	Skookumchuck	EMG	Total
Balance, Dec. 31, 2019	—	—	—
Contributions	86	16	102
Equity income	1	—	1
Change in foreign exchange rates	(2)	(1)	(3)
Balance, Dec. 31, 2020	85	15	100
Equity income	12	(3)	**9**
Distributions received	(4)	—	**(4)**
Balance, Dec. 31, 2021	**93**	**12**	**105**

A. Skookumchuck Wind Project

On Nov. 25, 2020, TransAlta completed the purchase of a 49 per cent interest in SP Skookumchuck Investments, LLC from Southern Power for cash consideration of $86 million (US$66 million). Skookumchuck is a 136.8 MW wind project located in Lewis and Thurston counties near Centralia in Washington state consisting of 38 Vestas V136 wind turbines. The project has a 20-year PPA with Puget Sound Energy.

B. EMG International Acquisition

On Nov. 30, 2020, TransAlta acquired a 30 per cent equity interest in EMG. Included in the purchase price of US$12 million is an estimated component contingent on EMG realizing certain earnings metrics in 2020 and 2021, following the acquisition. The final contingent amount will be calculated based on actual earnings metrics achieved. EMG is an established company with over 25 years of experience in process wastewater treatment and specializes in the design and construction of high-rate anaerobic digester systems. The investment provides an opportunity for TransAlta to leverage its expertise in on-site generation to support further advancements by EMG in the waste-to-energy space and will advance the Company's Clean Electricity Growth plan in the US market.

Summarized financial information on the results of operations relating to the Company's pro-rata interests in Skookumchuck and EMG is as follows:

Year ended Dec. 31	2021	2020
Results of operations		
Revenues	**19**	3
Expenses	**(10)**	(2)
Proportionate share of net earnings	**9**	1

11. Net Interest Expense

The components of net interest expense are as follows:

Year ended Dec. 31	2021	2020	2019
Interest on debt	**163**	158	161
Interest on exchangeable debentures (Note 25)	**29**	29	20
Interest on exchangeable preferred shares (Note 25)	**28**	5	—
Interest income	**(11)**	(10)	(13)
Capitalized interest (Note 18)	**(14)**	(8)	(6)
Interest on lease liabilities	**7**	8	4
Credit facility fees, bank charges and other interest	**18**	18	15
Tax shield on tax equity financing (Note 24)(1)	**(9)**	1	(35)
Interest on line loss rule proceeding (Note 36(H)(I))	**—**	5	—
Other(2)	**2**	2	10
Accretion of provisions (Note 23)	**32**	30	23
Net interest expense	**245**	238	179

(1) Credit in 2021 primarily relates to the tax benefit associated with investment tax credits claimed in 2021 on the North Carolina Solar projects that was assigned to the tax equity investor. Credit in 2019 primarily relates to the tax benefit associated with bonus tax depreciation claimed in 2019 on the Big Level and Antrim projects that was assigned to the tax equity investor. The tax equity investments are treated as debt under IFRS and the monetization of the tax attributes is considered a non-cash reduction of the debt balance and is reflected as a reduction in interest expense.
(2) In 2021, other interest expense included approximately nil (2020 — nil , 2019 — $5 million) for the significant financing component required under IFRS 15.

12. Income Taxes

A. Consolidated Statements of Earnings

I. Rate Reconciliations

Year ended Dec. 31	2021	2020	2019
Earnings (loss) before income taxes	**(380)**	(303)	193
Net earnings (loss) attributable to non-controlling interests not subject to tax	**(33)**	2	(26)
Adjusted earnings (loss) before income taxes	**(413)**	(301)	167
Statutory Canadian federal and provincial income tax rate (%)	**23.6%**	24.5%	26.5%
Expected income tax expense (recovery)	**(98)**	(74)	44
Increase (decrease) in income taxes resulting from:			
Differences in effective foreign tax rates	**4**	3	5
Deferred income tax expense related to temporary difference on investment in subsidiaries	**—**	9	—
Write-down (reversal of write-down) of unrecognized deferred income tax assets	**134**	8	(9)
Statutory and other rate differences	**4**	(7)	(31)
Other	**1**	11	8
Income tax expense (recovery)	**45**	(50)	17
Effective tax rate (%)	**(11%)**	17%	10%

II. Components of Income Tax Expense

The components of income tax expense are as follows:

Year ended Dec. 31	2021	2020	2019
Current income tax expense	**56**	35	35
Deferred income tax expense (recovery) related to the origination and reversal of temporary differences	**(145)**	(95)	22
Deferred income tax expense related to temporary difference on investment in subsidiary	**—**	9	—
Deferred income tax recovery resulting from changes in tax rates or laws	**—**	(7)	(31)
Deferred income tax expense (recovery) arising from the unrecognized deferred income tax assets(1)	**134**	8	(9)
Income tax expense (recovery)	**45**	(50)	17

Year ended Dec. 31	2021	2020	2019
Current income tax expense	**56**	35	35
Deferred income tax recovery	**(11)**	(85)	(18)
Income tax expense (recovery)	**45**	(50)	17

(1) During the year ended Dec. 31, 2021, the Company recorded a write-down of deferred tax assets of $134 million (2020 —$8 million write-down, 2019 — $9 million write-down reversal). In the current year additional deferred tax assets were created from the recognition of other comprehensive losses in the US. The deferred income tax assets mainly relate to the tax benefits of losses associated with the Company's directly owned US operations and Canadian operations. The Company evaluates at each period end, whether it is probable that sufficient future taxable income would be available from the Company's directly owned US operations to utilize the underlying tax losses.

B. 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	2021	2020	2019
Income tax expense (recovery) related to:			
Net impact related to cash flow hedges	**(57)**	(23)	6
Net actuarial gains (losses)	**11**	(3)	(7)
Income tax recovery reported in equity	**(46)**	(26)	(1)

C. Consolidated Statements of Financial Position

Significant components of the Company's deferred income tax assets (liabilities) are as follows:

As at Dec. 31	2021	2020
Net operating loss carryforwards(1)	**530**	469
Future decommissioning and restoration costs	**183**	140
Property, plant and equipment	**(651)**	(717)
Risk management assets and liabilities, net	**(53)**	(107)
Employee future benefits and compensation plans	**53**	62
Interest deductible in future periods	**17**	22
Foreign exchange differences on US-denominated debt	**16**	31
Other deductible temporary differences	**(5)**	2
Net deferred income tax liability, before write-down of deferred income tax assets	**90**	(98)
Unrecognized deferred income tax assets	**(380)**	(247)
Net deferred income tax liability, after write-down of deferred income tax assets	**(290)**	(345)

(1) Net operating losses expire between 2031 and 2040.

The net deferred income tax liability is presented in the Consolidated Statements of Financial Position as follows:

As at Dec. 31	2021	2020
Deferred income tax assets(1)	**64**	51
Deferred income tax liabilities	**(354)**	(396)
Net deferred income tax liability	**(290)**	(345)

(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.

D. Contingencies

As of Dec. 31, 2021, the Company had recognized a net liability of nil (2020 – nil) related to uncertain tax positions.

Ongoing CRA Audit

The Company is subject to routine audits of its tax filing positions by the Canada Revenue Agency ("CRA") on an ongoing basis. The CRA is currently examining the Company's tax filings for the 2015 taxation year and, in connection with such audit, is reviewing the internal reorganization completed in 2015. To date, the CRA has not proposed any reassessment of the Company's tax liability as a consequence of such audit and management believes that any reassessment would be without merit. The Company strongly believes that the Company's tax filing positions are appropriate, and accordingly no amounts have been accrued in the consolidated financial statements in respect of any such potential reassessment. If a notice of reassessment were issued, the Company would expect to vigorously oppose any such reassessment. If the CRA were to issue such a reassessment, the Company would be required to pay, on a provisional basis, up to 50 per cent of the amounts assessed, estimated to be between nil and $57 million. Any payment made by the Company in this context would be held by CRA until the final resolution of the dispute. The Company firmly believes it will be able to successfully defend its original filing position so that, ultimately, no increased income tax payable will result from the CRA's audit and any amounts paid to the CRA by the Company would be refunded.

13. Non-Controlling Interests

The Company's subsidiaries and operations that have non-controlling interests are as follows:

Subsidiary/Operation	Non-controlling interest as at Dec. 31, 2021
TransAlta Cogeneration L.P.	49.99% — Canadian Power Holdings Inc.
TransAlta Renewables	39.9% — Public shareholders
Kent Hills Wind LP[(1)]	17% — Natural Forces Technologies Inc.

(1) Owned by TransAlta Renewables.

TransAlta Cogeneration, L.P. ("TA Cogen") operates a portfolio of cogeneration facilities in Canada and owns 50 per cent of a dual-fuel generating facility. TransAlta Renewables owns and operates 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.

Summarized financial information relating to subsidiaries with significant non-controlling interests is as follows:

A. TransAlta Renewables

The net earnings, distributions and equity attributable to non-controlling interests include the 17 per cent non-controlling interest in the 167 MW Kent Hills wind facility located in New Brunswick.

Year ended Dec. 31	2021	2020	2019
Revenues	**470**	436	446
Net earnings	**139**	97	183
Total comprehensive earnings	**66**	223	138
Amounts attributable to the non-controlling interests:			
Net earnings	**50**	40	73
Total comprehensive earnings	**21**	90	56
Distributions paid to non-controlling interests	**100**	80	69

As at Dec. 31	2021	2020
Current assets	**430**	743
Long-term assets	**3,319**	2,913
Current liabilities	**(593)**	(364)
Long-term liabilities	**(1,033)**	(987)
Total equity	**(2,123)**	(2,305)
Equity attributable to non-controlling interests	**(869)**	(948)
Non-controlling interests' share (per cent)	**39.9**	39.9

In 2020, the Company's ownership per cent decreased from 60.4 per cent in 2019 to 60.1 per cent due to TransAlta Renewables issuing approximately 1 million common shares under their Dividend Reinvestment Plan ("DRIP"). The Company did not participate in this plan. In the fourth quarter of 2020, TransAlta Renewables suspended the DRIP in respect of any future declared dividends.

B. TA Cogen

Year ended Dec. 31	2021	2020	2019
Results of operations			
Revenues	**265**	146	181
Net earnings (loss)	**103**	(13)	43
Total comprehensive earnings (loss)	**103**	(13)	43
Amounts attributable to the non-controlling interest:			
Net earnings (loss)	**62**	(6)	21
Total comprehensive earnings (loss)	**62**	(6)	21
Distributions paid to Canadian Power Holdings Inc.	**56**	17	37

As at Dec. 31	2021	2020
Current assets	**66**	69
Long-term assets	**312**	323
Current liabilities	**(52)**	(78)
Long-term liabilities	**(36)**	(37)
Total equity	**(290)**	(277)
Equity attributable to Canadian Power Holdings Inc.	**(142)**	(136)
Non-controlling interest share (per cent)	**49.99**	49.99

In 2020, the Balancing Pool PPA concluded and the Sheerness facility became a merchant facility in 2021. This resulted in new protocols under the amended contractual agreement whereby the revenue and cost of sales for the facility are allocated based on dispatch activities. Capital and operating expenses continue to be allocated based on ownership interest.

14. Trade and Other Receivables

As at Dec. 31	2021	2020
Trade accounts receivable	**499**	488
Collateral paid (Note 16)	**55**	49
Current portion of finance lease receivables (Note 8)	**40**	36
Loan receivable (Note 22)	**55**	—
Income taxes receivable	**2**	10
Trade and other receivables	**651**	583

15. 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. The following table outlines the carrying amounts and classifications of the financial assets and liabilities:

Carrying value as at Dec. 31, 2021

	Derivatives used for hedging	Derivatives held for trading (FVTPL)	Amortized cost	Total
Financial assets				
Cash and cash equivalents[1]	–	–	947	947
Restricted cash	–	–	70	70
Trade and other receivables	–	–	651	651
Long-term portion of finance lease receivable	–	–	185	185
Risk management assets				
Current	36	272	–	308
Long-term	252	147	–	399
Financial liabilities				
Accounts payable and accrued liabilities	–	–	689	689
Dividends payable	–	–	62	62
Risk management liabilities				
Current	–	261	–	261
Long-term	–	145	–	145
Credit facilities, long-term debt and lease liabilities[2]	–	–	3,267	3,267
Exchangeable securities (Note 25)	–	–	735	735

(1) Includes cash equivalents of nil.
(2) Includes current portion.

Carrying value as at Dec. 31, 2020

	Derivatives used for hedging	Derivatives held for trading (FVTPL)	Amortized cost	Total
Financial assets				
Cash and cash equivalents[1]	–	–	703	703
Restricted cash	–	–	71	71
Trade and other receivables	–	–	583	583
Long-term portion of finance lease receivables	–	–	228	228
Risk management assets				
Current	102	69	–	171
Long-term	471	50	–	521
Other assets (Note 22)	–	–	52	52
Financial liabilities				
Accounts payable and accrued liabilities	–	–	599	599
Dividends payable	–	–	59	59
Risk management liabilities				
Current	10	84	–	94
Long-term	–	68	–	68
Credit facilities, long-term debt and lease liabilities[2]	–	–	3,361	3,361
Exchangeable securities (Note 25)	–	–	730	730

(1) Includes cash equivalents of nil.
(2) Includes current portion.

B. Fair Value of 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 that 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.

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 historical bootstrap 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.

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 businesses 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, 2021, are as follows: Level I – $12 million net asset (Dec. 31, 2020 – $13 million net liability), Level II – $122 million net asset (Dec. 31, 2020 – $27 million net liability) and Level III – $159 million net asset (Dec. 31, 2020 – $582 million net asset).

Significant changes in commodity net risk management assets (liabilities) during the year ended Dec. 31, 2021, are primarily attributable to volatility in market prices on both existing contracts and new contracts as well as contract settlements.

The following tables summarize 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, 2021 and 2020, respectively:

	Year ended Dec. 31, 2021			Year ended Dec. 31, 2020		
	Hedge	**Non-hedge**	**Total**	Hedge	Non-hedge	Total
Opening balance	**573**	**9**	**582**	678	8	686
Changes attributable to:						
Market price changes on existing contracts	**(181)**	**4**	**(177)**	(18)	3	(15)
Market price changes on new contracts	**—**	**(134)**	**(134)**	—	7	7
Contracts settled	**(107)**	**(5)**	**(112)**	(71)	(10)	(81)
Change in foreign exchange rates	**—**	**—**	**—**	(16)	1	(15)
Net risk management assets (liabilities) at end of period	**285**	**(126)**	**159**	573	9	582
Additional Level III information:						
Losses recognized in other comprehensive earnings	**(181)**	**—**	**(181)**	(34)	—	(34)
Total gains (losses) included in earnings before income taxes	**107**	**(130)**	**(23)**	71	11	82
Unrealized gains (losses) included in earnings before income taxes relating to net assets held at period end	**—**	**(135)**	**(135)**	—	1	1

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 system. 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, system-generated 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, 2021, the total Level III risk management asset balance was $305 million (2020 – $615 million) and Level III risk management liability balance was $146 million (2020 – $33 million). 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. 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. During 2021, the sensitivities include the effects of liquidity and credit value adjustments.

As at	**Dec. 31, 2021**			
Description	**Sensitivity**	**Valuation technique**	**Unobservable input**	**Reasonable possible change**
Long-term power sale – US	+22 -145	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$3 or price increase of US$20
Coal transportation – US	+3 -18	Numerical derivative valuation	Illiquid future power prices (per MWh) Volatility Rail rate escalation	Price decrease of US$3 or price increase of US$20 80% to 120% zero to 4%
Full requirements – Eastern US	+9 -9	Historical bootstrap	Volume Cost of supply	95% to 105% (+/-) US$1 per MWh
Long-term wind energy sale – Eastern US	+17 -16	Long-term price forecast	Illiquid future power prices (per MWh) Illiquid future REC prices (per unit)	Price increase or decrease of US$6 Price decrease of US$3 or increase of US$2
Long-term wind energy sale – Canada	+21 -11	Long-term price forecast	Illiquid future power prices (per MWh) Wind discounts	Price decrease of C$24 or increase of C$5 5% decrease or 5% increase
Long-term wind energy sale - Central US	+27 -15	Long-term price forecast	Illiquid future power prices (per MWh) Wind discounts	Price decrease of US$2 or increase of US$3 3% decrease or 3% increase
Others	+6 -6			

As at	Dec. 31, 2020			
Description	Sensitivity	Valuation technique	Unobservable input	Reasonable possible change
Long-term power sale – US	+35 -59	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$3 or a price increase of US$5
Coal transportation – US	+3 -5	Numerical derivative valuation	Illiquid future power prices (per MWh) Volatility Rail rate escalation	Price decrease of US$3 or a price increase of US$5 80% to 120% zero to 4%
Full requirements – Eastern US	+3 -3	Historical bootstrap	Volume Cost of supply	95% to 105% (+/-) US$1 per MWh
Long-term wind energy sale – Eastern US	+22 -22	Long-term price forecast	Illiquid future power prices (per MWh) Illiquid future REC prices (per unit)	Price increase or decrease of US$6 Price increase or decrease of US$1
Others	+5 -5			

i. 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.

For periods beyond 2023, market forward power prices are not readily observable. For these periods, fundamental-based forecasts and market indications have been used to determine proxies for base, high and low power price scenarios. The base price forecast has been developed by using a fundamental-based forecast (the provider is an independent and widely accepted industry expert for scenario and planning views).

The contract is denominated in US dollars. The US dollar relative to the Canadian dollar remained consistent from Dec. 31, 2020, to Dec. 31, 2021, resulting in the sensitivity values remaining consistent. The balance for this contract at Dec. 31, 2021 decreased mainly due to higher forward power prices compared to previously estimated prices.

ii. Coal Transportation - US
The Company has a coal rail transport agreement that includes an upside sharing mechanism, with a contract start date of Jan. 1, 2021, that extends until Dec. 31, 2025. Option pricing techniques have been utilized to value the obligation associated with this component of the deal.

The key unobservable inputs used in the valuation include non-liquid power prices, option volatility and rail rate escalation. Reasonably possible alternative inputs were used to determine sensitivity on the fair value measurements.

For periods beyond 2023, market forward power prices are not readily observable. For these periods, fundamental-based forecasts and market indications have been used to determine proxies for base, high and low power price scenarios. The base price forecast has been developed by using a fundamental-based forecast (the provider is an independent and widely accepted industry expert for scenario and planning views). Option volatility and rail rate escalation ranges have been determined based on historical data and professional judgment.

iii. 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. Reasonable possible alternative inputs are used to determine sensitivity on the fair value measurement.

iv. Long-Term Wind Energy Sale – Eastern US
In relation to the Big Level wind facility, the Company has a long-term contract for differences whereby the Company receives a fixed price per MWh and pays the prevailing real-time energy market price per MWh as well as the physical delivery of renewable energy credits based on proxy generation. Commercial operation of the facility was achieved in December 2019, with the contract commencing on July 1, 2019, and extending for 15 years after the commercial operation date. The contract is accounted for at fair value through profit or loss.

The key unobservable inputs used in the valuation of the contract are expected proxy generation volumes and non-liquid forward prices for power and RECs.

v. Long-Term Wind Energy Sale – Canada
In relation to the Garden Plain wind project, the Company has entered into a virtual PPA whereby the Company receives the difference between the fixed contract price per MWh and the Alberta Electric System Operator ("AESO") settled pool price per MWh. The contract commences on commercial operation of the facility, which is expected by the end of 2022, and extending for 18 years past that date. The energy component of the contract is accounted for at fair value through profit or loss.

In addition to the virtual PPA contract, the Company has entered into a "bridge contract" that runs 16 months from Sept. 1, 2021 through Dec. 31, 2022, with the potential for extension at the virtual PPA price, depending on the commencement of commercial operations.

Under a separate agreement, Pembina has the option to purchase a 37.7 per cent interest in the project (49 per cent of the PPA). The option must be exercised no later than 30 days after commercial operational date.

The key unobservable inputs used in the valuation of the contracts are the non-liquid forward prices for power and monthly wind discounts.

vi. *Long-Term Wind Energy Sale – Central US*
On Dec. 22, 2021, TransAlta executed two long-term virtual PPAs for the off take of 100 per cent of the generation from its 300 MW White Rock East and White Rock West wind power projects (collectively, the "White Rock Wind Projects") to be located in Caddo County, Oklahoma. The Company receives the difference between the fixed contract price per MWh and the settled pool price per MWh. The contracts commence on commercial operation of the facilities, which is expected within the second half of 2023, and extend for 15 years past that date. The energy component of the contracts is accounted for at fair value through profit or loss.

The key unobservable inputs used in the valuation of the contracts are the non-liquid forward prices for power and monthly wind discounts.

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 $8 million as at Dec. 31, 2021 (Dec. 31, 2020 – $12 million net liability) are classified as Level II fair value measurements. The significant changes in other net risk management assets and liabilities during the year ended Dec. 31, 2021, are primarily attributable to favourable market prices on existing contracts.

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, 2021	**—**	**770**	**—**	**770**	**735**
Long-term debt — Dec. 31, 2021	**—**	**3,272**	**—**	**3,272**	**3,167**
Exchangeable securities — Dec. 31, 2020	—	769	—	769	730
Long-term debt — Dec. 31, 2020	—	3,480	—	3,480	3,227

(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 paid, accounts payable and accrued liabilities, collateral received and dividends payable) approximates fair value due to the liquid nature of the asset or liability. The fair values of the loan receivable (see Note 22) and the finance lease receivables (see Note 8) approximate the carrying amounts.

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 15 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, and a reconciliation of changes is as follows:

As at Dec. 31	**2021**	2020	2019
Unamortized net gain (loss) at beginning of year	**(33)**	9	49
New inception gain (loss)[1]	**(50)**	(13)	3
Amortization recorded in net earnings during the year	**(19)**	(29)	(43)
Unamortized net gain (loss) at end of year[2]	**(102)**	(33)	9

(1) During 2021, the Company entered into PPAs for the White Rock Wind Projects that resulted in a new inception loss 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 power agreement contract period. During 2020, the Company entered into a coal rail transportation agreement that includes an upside sharing mechanism. Option pricing techniques have been utilized to value the obligation associated with this component of the deal.
(2) During 2020, the net inception gain on the long-term fixed price power sale contract in the US changed to a loss position based on the day one forward price curve at inception of the contract.

16. 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, 2021

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	**33**	**12**	**45**
Long-term	**252**	**(4)**	**248**
Net commodity risk management assets	**285**	**8**	**293**
Other			
Current	**3**	**(1)**	**2**
Long-term	**—**	**6**	**6**
Net other risk management assets	**3**	**5**	**8**
Total net risk management assets	**288**	**13**	**301**

As at Dec. 31, 2020

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	101	(11)	90
Long-term	471	(19)	452
Net commodity risk management assets (liabilities)	572	(30)	542
Other			
Current	(9)	(4)	(13)
Long-term	—	1	1
Net other risk management liabilities	(9)	(3)	(12)
Total net risk management assets (liabilities)	563	(33)	530

I. 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	**2021**				2020			
	Current financial assets	**Long-term financial assets**	**Current financial liabilities**	**Long-term financial liabilities**	Current financial assets	Long-term financial assets	Current financial liabilities	Long-term financial liabilities
Gross amounts recognized	**394**	**330**	**(306)**	**(122)**	120	69	(132)	(104)
Gross amounts set-off	**(137)**	**(53)**	**138**	**54**	(69)	(10)	69	10
Net amounts as included in the Consolidated Statements of Financial Position	**257**	**277**	**(168)**	**(68)**	51	59	(63)	(94)

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 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 pre-defined 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 and for its portfolio of merchant power exposure in Alberta, including a long-term physical power sale contract at Centralia and fixed price financial swaps for the Alberta portfolio to hedge the prices. Both hedging strategies fall under the Company's risk management strategy used to hedge commodity price risk.

There is no source of hedge ineffectiveness for the merchant power exposure in Alberta.

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.

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, 2021, associated with the Company's proprietary trading activities was $2 million (2020 — $1 million, 2019 — $1 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, 2021, associated with the Company's commodity derivative instruments used in generation hedging activities was $33 million (2020 — $12 million, 2019 — $25 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, 2021, associated with these transactions was $51 million (2020— $15 million, 2019 — $8 million).

iii. Commodity Price Risk Management – Hedges

The Company's outstanding commodity derivative instruments designated as hedging instruments are as follows:

As at Dec. 31	**2021**		2020	
Type (thousands)	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity (MWh)[1]	—	—	95	—

(1) Excludes the long-term power sale - US contract. For further details on this contract, refer to Note 15(B)(I)(c)(i).

During 2021, unrealized pre-tax losses of $1 million (2020 — $1 million gains, 2019 — $1 million gains) related to certain power hedging relationships that were previously de-designated and deemed ineffective for accounting purposes were released from AOCI and recognized in net earnings.

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	**2021**		2020	
Type (thousands)	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity (MWh)	**46,139**	**14,951**	12,944	8,258
Natural gas (GJ)	**7,501**	**173,898**	23,035	177,448
Transmission (MWh)	**37**	**1,097**	—	1,578
Emissions (MWh)	**445**	**2,030**	1,831	2,112
Emissions (tonnes)	**350**	**350**	2,160	2,365
Coal (tonnes)	**—**	**9,352**	—	9,078

b. Interest Rate Risk Management

Interest rate risk arises as the fair value of future cash flows from a financial instrument fluctuates because of changes in market interest rates. Changes in interest rates can impact the Company's borrowing costs. Changes in the cost of capital may also affect the feasibility of new growth initiatives.

The Company's credit facility and the Poplar Creek non-recourse bond are the only debt instruments subject to floating interest rates, which represent 3 per cent of the Company's debt as at Dec. 31, 2021 (2020 – 7 per cent). Interest rate risk is managed with the use of derivatives. The Company's outstanding interest rate derivative instruments are as follows:

In 2021, the Company had interest rate swap agreements in place with a notional amount of US$150 million (2020 — US$150 million) whereby the Company receives a variable rate of interest equal to the three-month LIBOR rate and pays interest at a fixed rate equal to 0.94 per cent (2020 — 0.94 per cent) on the notional amount. The swaps are being used to hedge interest rate exposure on a highly probable future US$400 million fixed rate debt issuance, expected to occur in 2022.

In 2021, the Company had bond lock agreements in place with a total notional amount of US$150 million (2020 — $75 million) whereby on the pricing date, if the difference between the underlying 1.375 per cent US Treasury bond (2020 — 5.75 per cent Government of Canada bond) and the forward bond yield (2020 — $150 million forward yield 1.20 per cent) is positive, the Company receives settlement. If the difference is negative, the Company pays settlement. The bond lock is being used to hedge interest rate exposure on a highly probable future US$400 million (2020 —$150 million) fixed rate debt issuance. The $75 million bond lock outstanding at Dec. 31, 2020, was settled in 2021.

There were no interest rate derivative instruments outstanding in 2019.

LIBOR 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 facility references LIBOR for US dollar drawings and Canadian Dollar Offer Rate ("CDOR") for Canadian dollar drawings, and includes appropriate fallback language to replace these benchmark rates if a benchmark transition event were to occur. Currently there are no drawings on the facility. The non-recourse bond references the three-month CDOR: however, only the six- and 12-month CDOR have been discontinued with no expectation to stop publishing other CDOR rates at this time.

In addition, the Company has interest rate swap agreements in place with a notional amount of US$150 million referencing the three-month LIBOR, expected to settle in the third quarter of 2022. The cessation date for three-month LIBOR is June 30, 2023.

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, 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 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 (2020 — US$370 million).

ii. Cash Flow Hedges
The Company uses foreign exchange forward contracts to hedge a portion of its future foreign-denominated receipts and expenditures, and both foreign exchange forward contracts and cross-currency swaps to manage foreign exchange exposure on foreign-denominated debt not designated as a net investment hedge.

As at Dec. 31		**2021**		2020			
Notional amount sold	**Notional amount purchased**	**Fair value liability**	**Maturity**	Notional amount sold	Notional amount purchased	Fair value liability	Maturity
Foreign exchange forward contracts - foreign-denominated receipts/expenditures							
CAD10	**USD8**	**—**	**2022**	CAD71	USD54	(2)	2021
AUD19	**USD14**	**—**	**2022**	—	—	—	—

iii. Non-Hedges
The Company also uses foreign currency contracts to manage its expected foreign operating cash flows. Hedge accounting is not applied to these foreign currency contracts.

As at Dec. 31	**2021**				2020			
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								
AUD28	**CAD26**	**(5)**	**2022-2025**		AUD197	CAD181	(14)	2021 - 2024
USD271	**CAD357**	**8**	**2022-2025**		USD47	CAD72	9	2021 - 2024
					AUD4	USD3	—	2021
					CAD1	EUR1	—	2021
Foreign exchange forward contracts – foreign-denominated debt								
CAD191	**USD150**	1	**2022**		CAD191	USD150	2	2022

iv. 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 cent (2020 — three cent, 2019 — three cent) increase or decrease in these currencies relative to the Canadian dollar is a reasonable potential change over the next quarter.

Year ended Dec. 31	**2021**		2020		2019	
Currency	**Net earnings increase (decrease)[1]**	**OCI gain[1][2]**	Net earnings decrease[1]	OCI gain[1][2]	Net earnings decrease[1]	OCI gain[1][2]
USD	**(13)**	**1**	(8)	1	(18)	2
AUD	**1**	**—**	(4)	—	(6)	—
Total	**(12)**	**1**	(12)	1	(24)	2

(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, 2021:

	Investment grade *(Per cent)*	**Non-investment grade** *(Per cent)*	**Total** *(Per cent)*	**Total amount**
Trade and other receivables[1,2]	89	11	**100**	**651**
Long-term finance lease receivable	100	—	**100**	**185**
Risk management assets[1]	86	14	**100**	**707**
Total				**1,543**

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.
(2) Includes loan receivable with a counterparty that has no external credit rating. Refer to Note 22 for further details.

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 significant expected credit losses as at Dec. 31, 2021.

The Company's maximum exposure to credit risk at Dec. 31, 2021, 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, 2021, was $37 million (2020 — $22 million).

Amidst the current economic conditions resulting from the COVID-19 pandemic, TransAlta has implemented the following additional measures to monitor its counterparties for changes in their ability to meet obligations:

- Daily monitoring of events impacting counterparty creditworthiness and counterparty credit downgrades;
- Weekly oversight and follow-up, if applicable, of accounts receivables; and
- Review and monitoring of key suppliers, counterparties and customers (i.e., offtakers).

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.

III. Liquidity Risk

Liquidity risk relates to the Company's ability to access capital to be used for proprietary trading activities, commodity hedging, capital projects, debt refinancing and general corporate purposes. As at Dec. 31, 2021, TransAlta maintains an investment grade rating from one credit rating agency and below investment grade ratings from two credit rating agencies. Between 2022 and 2024, the Company has approximately $1 billion of debt maturing, comprised of approximately $515 million of recourse debt, with the balance mainly related to scheduled non-recourse debt repayments and the classification of the Kent Hills Wind LP bond as current.

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 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:

	2022	2023	2024	2025	2026	2027 and thereafter	Total
Accounts payable and accrued liabilities	689	—	—	—	—	—	689
Long-term debt[(1)]							
Debentures	—	—	—	—	—	251	251
Senior Notes	511	—	—	—	—	383	894
Non-recourse — Hydro	—	45	—	—	—	—	45
Non-recourse — Wind & Solar	263	49	52	54	51	283	752
Non-recourse — Gas	44	45	47	59	61	855	1,111
Tax equity financing	15	15	14	14	15	68	141
Other	3	1	—	—	—	—	4
Exchangeable securities[(2)]	—	—	—	750	—	—	750
Commodity risk management (assets) liabilities	(45)	(35)	(117)	(95)	1	(2)	(293)
Other risk management (assets) liabilities	(2)	(3)	(3)	1	—	(1)	(8)
Lease liabilities[(3)]	(6)	4	3	3	3	93	100
Interest on long-term debt and lease liabilities[(4)]	149	120	115	109	104	787	1,384
Interest on exchangeable securities[(2, 4)]	53	53	62	—	—	—	168
Dividends payable	62	—	—	—	—	—	62
Total	**1,736**	**294**	**173**	**895**	**235**	**2,717**	**6,050**

(1) Excludes impact of hedge accounting and derivatives.
(2) Assumes the exchangeable securities will be exchanged on Jan. 1, 2025. Refer to Note 25 for further details.
(3) Lease liabilities include a lease incentive of $13 million expected to be received in 2022.
(4) Not recognized as a financial liability on the Consolidated Statements of Financial Position.

IV. Equity Price Risk

a. 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					
	2022	2023	2024	2025	2026	2027 and thereafter
Cash flow hedges						
Foreign currency forward contracts						
Notional amount ($ millions)						
CAD/USD	8	—	—	—	—	—
AUD/USD	14	—	—	—	—	—
Average Exchange Rate						
CAD/USD	0.7893	—	—	—	—	—
AUD/USD	0.7352	—	—	—	—	—
Commodity derivative instruments						
Electricity						
Notional amount (thousands MWh)	3,329	3,329	3,338	2,628	—	—
Average price ($ per MWh)	71.95	73.76	75.6	77.49	—	—

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, 2021

	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	**13 MMWh**	**285**	**Risk management assets**	**(181)**
Interest rate risk				
Cash flow hedges				
Interest rate swap	**USD300**	**3**	**Risk management assets**	**3**
Foreign currency risk				
Cash flow hedges				
Foreign-denominated expenditures	**USD8**	**—**	**Risk management assets**	**—**
Foreign-denominated expenditures	**USD14**	**—**	**Risk management assets**	**—**
Net investment hedges				
Foreign-denominated debt	**USD370**	**CAD473**	**Credit facilities, long-term debt and lease liabilities**	**—**

As at Dec. 31, 2020

	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	16 MMWh	573	Risk management assets	(33)
Interest rate risk				
Cash flow hedges				
Interest rate swap	USD150	(3)	Risk management liabilities	3
Interest rate swap	CAD75	(4)	Risk management liabilities	4
Foreign currency risk				
Net investment hedges				
Foreign-denominated debt	USD370	CAD472	Credit facilities, long-term debt and lease liabilities	11

The impact of the hedged items on the statement of financial position is as follows:

As at Dec. 31	2021		2020	
	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	**(181)**	**226**	(33)	417
Interest rate risk				
Cash flow hedges				
Interest expense on long-term debt	**3**	**2**	7	19
	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	**—**	**(35)**	11	(21)

(1) Included in AOCI.

The hedging 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 hedged items designated in hedging relationships on OCI and net earnings is:

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**	**—**

Over the next 12 months, the Company estimates that approximately $25 million of after-tax gain 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, 2020					
		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	41	Revenue	(137)	Revenue	—
Foreign exchange forwards on project hedges	(1)	Property, plant and equipment	—	Foreign exchange (gain) loss	—
Forward starting interest rate swaps	(12)	Interest expense	(4)	Interest expense	—
OCI impact	28	OCI impact	(141)	Net earnings impact	—

	Year ended Dec. 31, 2019				
		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	77	Revenue	(59)	Revenue	—
Forward starting interest rate swaps	—	Interest expense	6	Interest expense	—
OCI impact	77	OCI impact	(53)	Net earnings impact	—

II. Effect of Non-Hedges

For the year ended Dec. 31, 2021, the Company recognized a net unrealized gain of $97 million (2020 — gain of $43 million, 2019 — gain of $33 million) related to commodity derivatives.

For the year ended Dec. 31, 2021, a gain of $6 million (2020 — gain of $11 million, 2019 —gain of $24 million) related to foreign exchange and other derivatives was recognized, which consists of net unrealized gains of $4 million (2020 — loss of $2 million, 2019 — gain of $6 million) and net realized gains of $2 million (2020 — gains of $13 million, 2019 — gains of $18 million), respectively.

F. Collateral

I. Financial Assets Provided as Collateral

At Dec. 31, 2021, the Company provided $55 million (2020 – $49 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 in accounts receivable in the Consolidated Statements of Financial Position.

II. Financial Assets Held as Collateral

At Dec. 31, 2021, the Company held $18 million (2020 – nil) 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 included in accounts payable 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.

As at Dec. 31, 2021, the Company had posted collateral of $356 million (2020 – $163 million) in the form of letters of credit on derivative instruments 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 $120 million (2020 – $85 million) of collateral to its counterparties.

17. Inventory

The components of inventory are as follows:

As at Dec. 31	2021	2020
Parts and materials	82	107
Coal	27	83
Deferred stripping costs	—	8
Natural gas	3	2
Purchased emission credits(1)	55	38
Total	**167**	238

(1) Purchased emissions credits increased due to trading and compliance credits purchased, including those for Alberta compliance under the Technology Innovation and Emissions Reduction program.

No inventory is pledged as security for liabilities.

Carbon compliance costs are regulated costs that the business incurs as a result of greenhouse gas emissions generated from our operating units. TransAlta's exposure to carbon compliance costs is mitigated through the use of eligible emission credits generated from the Company's Wind and Solar and Hydro segments, as well as, purchasing emission credits from the market at prices lower than the regulated compliance price of carbon. Emission credits generated from our Alberta business have no recorded book value but are expected to be used to offset emission obligations from our gas facilities located in Canada in the future when the compliance price of carbon is expected to increase, resulting in a reduced cash cost for carbon compliance. At Dec. 31, 2021, the Company currently holds 2,033,752 purchased emission credits (2020 — 1,434,761) recorded at $55 million (2020 — $38 million) and approximately 1,922,973 (2020 — 1,211,230) emission credits with no recorded book value.

The change in inventory is as follows:

	2021	2020
Balance, Jan. 1	238	251
Net additions (use)	22	26
Write-downs, coal	(65)	(37)
Write-downs, parts and materials	(28)	—
Change in foreign exchange rates	—	(2)
Balance, Dec. 31	**167**	238

With the decision in 2020 to adjust the useful life of the Highvale mine assets to align with the Company's conversion to gas plans, the standard cost of coal increased during 2021 and 2020 as a result of increased depreciation costs and reduced coal consumption. During the same period, as the cost of the coal was not expected to be recovered based on power pricing, the Company recognized a $65 million (2020 — $37 million) write-down to net realizable value on its internally produced coal inventory for the year ended Dec. 31, 2021, of which $48 million relates to increased depreciation from the accelerated closure of the mine.

In addition, OM&A costs included a write-down of $28 million, for parts and material inventory related to the Highvale mine and coal operations at our natural gas converted facilities. With the accelerated shutdown of the Highvale mine and full conversion to natural gas completed in 2021. It was determined that a portion of the coal-related parts and materials inventory would not be utilized in the operations of our converted natural gas facilities and therefore the value was adjusted down to the expected net realizable amounts for the end of 2021.

18. Property, Plant and Equipment

A reconciliation of the changes in the carrying amount of PP&E is as follows:

	Land	Renewable generation	Gas generation[1]	Energy Transition[1]	Assets under construction	Capital spares and other[2]	Total
Cost							
As at Dec. 31, 2019, as previously reported	91	3,574	1,671	7,342	228	489	13,395
Adjustments due to re-segmentation	—	—	2,402	(2,402)	—	—	—
As at Dec 31, 2019, adjusted	91	3,574	4,073	4,940	228	489	13,395
Additions	—	—	—	—	478	8	486
Acquisitions (Note 4)	—	—	1	—	—	—	1
Disposals	(2)	—	—	(1)	—	(2)	(5)
Impairment (Note 7)	(9)	(2)	—	(69)	—	(1)	(81)
Revisions and additions to decommissioning and restoration costs (Note 23)	—	8	1	85	—	—	94
Retirement of assets	—	(7)	(47)	(3)	—	(1)	(58)
Change in foreign exchange rates	(1)	(14)	45	(39)	—	6	(3)
Transfers	17	33	(138)	(12)	(211)	(120)	(431)
As at Dec. 31, 2020, adjusted	96	3,592	3,935	4,901	495	379	13,398
Additions	**—**	**—**	**—**	**—**	**478**	**2**	**480**
Acquisitions (Note 4)	**—**	**146**	**—**	**—**	**—**	**—**	**146**
Disposals	**(1)**	**—**	**(2)**	**(74)**	**(2)**	**—**	**(79)**
Impairment (Note 7)	**—**	**(15)**	**(2)**	**(468)**	**(91)**	**(13)**	**(589)**
Revisions and additions to decommissioning and restoration costs (Note 23)	**—**	**129**	**6**	**—**	**—**	**—**	**135**
Retirement of assets	**—**	**(15)**	**(57)**	**(49)**	**—**	**—**	**(121)**
Change in foreign exchange rates	**—**	**3**	**(25)**	**2**	**—**	**(6)**	**(26)**
Transfers	**1**	**303**	**232**	**201**	**(696)**	**4**	**45**
As at Dec. 31, 2021	**96**	**4,143**	**4,087**	**4,513**	**184**	**366**	**13,389**
Accumulated depreciation							
As at Dec. 31, 2019, as previously reported	—	1,284	900	4,836	—	168	7,188
Adjustments due to re-segmentation	—	—	1,137	(1,137)	—	—	—
As at Dec 31, 2019, adjusted	—	1,284	2,037	3,699	—	168	7,188
Depreciation	—	141	258	304	—	14	717
Retirement of assets	—	(5)	(43)	(3)	—	—	(51)
Disposals	—	—	—	(1)	—	(1)	(2)
Change in foreign exchange rates	—	(4)	18	(37)	—	2	(21)
Transfers	—	—	(212)	(29)	—	(14)	(255)
As at Dec. 31, 2020, adjusted	—	1,416	2,058	3,933	—	169	7,576
Depreciation	**—**	**154**	**184**	**264**	**—**	**12**	**614**
Retirement of assets	**—**	**(9)**	**(55)**	**(48)**	**—**	**—**	**(112)**
Disposals	**—**	**—**	**(1)**	**(72)**	**—**	**—**	**(73)**
Change in foreign exchange rates	**—**	**—**	**(8)**	**2**	**—**	**(1)**	**(7)**
Transfers	**—**	**—**	**—**	**71**	**—**	**—**	**71**
As at Dec. 31, 2021	**—**	**1,561**	**2,178**	**4,150**	**—**	**180**	**8,069**
Carrying amount							
As at Dec. 31, 2019, adjusted	91	2,290	2,036	1,241	228	321	6,207
As at Dec. 31, 2020, adjusted	96	2,176	1,877	968	495	210	5,822
As at Dec. 31, 2021	**96**	**2,582**	**1,909**	**363**	**184**	**186**	**5,320**

(1) The gas generation and energy transition includes the previously disclosed coal generation and mining property and equipment categories.
(2) Includes major spare parts and stand-by equipment available, but not in service and spare parts used for routine, preventive or planned maintenance.

A. Renewable Generation

During 2021, the Company acquired North Carolina Solar (Refer to Note 4 for further details).

During the third quarter of 2021, Kent Hills 2 had a tower collapse resulting in an impairment of $2 million. Following extensive independent engineering assessments and root cause failure analysis, the Company announced on Jan. 11, 2022, that all 50 turbine foundations at the Kent Hills 1 and Kent Hills 2 sites require a full foundation replacement. As the turbines will not be returning to service until the foundations are replaced, the foundations were written off, resulting in an increase in depreciation of $12 million.

Transfers from assets under construction in 2021 are related to the Windrise wind facility of $255 million, Kent Hills wind rehabilitation project of $7 million and the balance is related to other wind and hydro facilities. Transfers between the classifications of PP&E in 2020 relate to the WindCharger project and planned major maintenance.

B. Gas Generation

During 2021, the Company completed the full conversion of Keephills Unit 2, Keephills Unit 3 and Sundance Unit 6 from thermal coal to natural gas. Transfers from assets under construction of $200 million relates to the planned coal to gas conversions and the balance is related to the Australian and US gas facilities.

During 2019, the sale of Genesee 3 resulted in a gain of $77 million, which was recognized in gains on sale of assets and other on the statement of earnings during the fourth quarter.

Transfers out of PP&E in 2020 mainly relate to removing the Southern Cross assets from PP&E to a finance lease receivable and moving the Pioneer Pipeline and mine equipment to assets held for sale. Transfers between the classifications of PP&E in 2020 relate to the Sundance Unit 6 conversion to gas.

C. Energy Transition Generation

Keephills Unit 1, Sundance Unit 5 and Sundance Unit 3 were retired from service effective Dec. 31, 2021, Nov. 1, 2021, and July 31, 2020, respectively. Sundance Unit 4 will be retired effective April 1, 2022. During 2021, the Company sold equipment related to coal generation that resulted in a gain of sale of $23 million. Centralia Unit 1 was retired from service effective Dec. 31, 2020, as originally planned.

Transfers from assets under construction in 2021 are mainly related to Keephills Unit 1 of $20 million, Sundance Unit 5 of $78 million and the mining property and equipment related to SunHills and Centralia of $100 million. The Company transferred certain generation assets from the Energy Transition segment to assets held for sale as a result of its assessment under IFRS 5 — *Non-current Assets Held for Sale and Discontinued Operations.* As part of this review there were no impairment charges recognized against the carrying value of $25 million. Transfers between the classifications of PP&E in 2020 relate to the Centralia land purchase.

During the third quarter of 2020, the Board approved the accelerated shutdown of the Highvale mine by the end of 2021 and accordingly the useful life of the related assets was adjusted to align with the Company's conversion to gas plans. This resulted in an increase of $15 million in depreciation expense that was recognized in the Consolidated Statements of Earnings (Loss) during the second half of 2020.

D. Assets Under Construction

Initial construction activities on the Garden Plain wind project started in the third quarter of 2021. In addition, the Company commenced construction in the fourth quarter of 2021 on the Northern Goldfields Solar Project. The Northern Goldfields Solar Project comprises the 27 MW Mount Keith Solar Farm, 11 MW Leinster Solar Farm, 10MW/5MWh Leinster battery energy storage system and interconnecting transmission infrastructure, all of which will be integrated into our existing 169 MW Southern Cross Energy North remote network in Western Australia. Upon completion of construction, these will be transferred to finance lease receivables.

Additions in 2021 are related to the Windrise wind project of $96 million (2020 — $156 million), White Rock Wind Projects of $32 million (2020 — nil), Garden Plain wind project of $38 million (2020 — nil), the Kaybob cogeneration project of $14 million (2020 — $31 million), coal to gas conversions of $91 million (2020 — $93 million) and planned major maintenance expenditures. In 2020, the additions included the WindCharger battery storage project of $6 million and Centralia mine land of $17 million.

Transfers out to assets held for sale include $25 million related to salvage values for Sundance Unit 5 repowering project.

In 2021, the Company capitalized $14 million (2020 — $8 million) of interest to PP&E in at a weighted average rate of 6.0 per cent (2020 — 6.0 per cent).

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	Pipeline	Total
As at Dec. 31, 2019	58	16	2	25	45	146
Additions	3	13	—	—	—	16
Depreciation	(3)	(5)	(1)	(9)	(3)	(21)
As at Dec. 31, 2020	58	24	1	16	42	141
Additions	**—**	**1**	**—**	**—**	**—**	**1**
Acquisitions (Note 4)	**13**	**—**	**—**	**—**	**—**	**13**
Depreciation	**(3)**	**(5)**	**—**	**(2)**	**(1)**	**(11)**
Disposal of assets (Note 4)	**—**	**—**	**—**	**—**	**(41)**	**(41)**
Transfers	**—**	**—**	**—**	**(8)**	**—**	**(8)**
As at Dec. 31, 2021	**68**	**20**	**1**	**6**	**—**	**95**

On June 30, 2021, the Company closed the sale of the Pioneer Pipeline to ATCO. As part of the transaction, the natural gas transportation agreement with the Pioneer Pipeline Limited Partnership was terminated, which resulted in the derecognition of the right-of-use asset of $41 million and lease liability of $43 million related to the pipeline, resulting in a gain of $2 million.

For the year ended Dec. 31, 2021, TransAlta paid $15 million (2020 — $33 million) related to recognized lease liabilities, consisting of $7 million in interest (2020 — $8 million) and $8 million (2020 — $25 million) in principal repayments.

Short-term leases (term of less than 12 months) and leases with total lease payments below the Company's capitalization threshold do not require recognition as lease liabilities and right-of-use assets.

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, 2021, the Company expensed $6 million (2020 — $7 million) in variable land lease payments for these leases. For further information regarding leases refer to Note 5, 11, 24 and 36.

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, 2019	250	378	11	149	788
Additions	—	—	14	—	14
Acquisition (Note 4)	37	—	—	—	37
Disposals	—	(1)	—	—	(1)
Change in foreign exchange rates	(2)	—	—	—	(2)
Transfers	(16)	35	(22)	—	(3)
As at Dec. 31, 2020	269	412	3	149	833
Additions	**—**	**—**	**9**	**—**	**9**
Impairment (Note 7)	**—**	**—**	**—**	**(17)**	**(17)**
Change in foreign exchange rates	**—**	**(2)**	**—**	**—**	**(2)**
Transfers	**—**	**12**	**(8)**	**—**	**4**
As at Dec. 31, 2021	**269**	**422**	**4**	**132**	**827**
Accumulated amortization					
As at Dec. 31, 2019	107	246	—	117	470
Amortization	15	28	—	8	51
Disposals	—	(1)	—	—	(1)
Transfers	1	(1)	—	—	—
As at Dec. 31, 2020	123	272	—	125	520
Amortization	**17**	**27**	**—**	**7**	**51**
As at Dec. 31, 2021	**140**	**299**	**—**	**132**	**571**
Carrying amount					
As at Dec. 31, 2019	143	132	11	32	318
As at Dec. 31, 2020	146	140	3	24	313
As at Dec. 31, 2021	**129**	**123**	**4**	**—**	**256**

21. Goodwill

Goodwill acquired through business combinations has been allocated to CGUs that are expected to benefit from the synergies of the acquisitions. Goodwill by segments are as follows:

As at Dec. 31	**2021**	2020
Hydro	**258**	258
Wind and Solar	**175**	175
Energy Marketing	**30**	30
Total goodwill	**463**	463

For the purposes of the 2021 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 based on the Company's long-range forecasts for the period extending to the last planned asset retirement in 2052. The resulting fair value measurement is categorized within Level III of the fair value hierarchy. In 2021, the Company relied on the recoverable amounts determined in 2019 for the Hydro and Energy Marketing segments in performing the 2021 goodwill impairment review. No impairment of goodwill arose for any segment.

The key assumptions impacting the determination of fair value for the Wind and Solar and Hydro segments are the following:

- Discount rates used for the goodwill impairment calculation in 2021 for the Wind and Solar segment ranged from 5.0 per cent to 6.4 per cent (2020 – 4.8 per cent to 6.3 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.
- Forecasted 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. Electricity prices used in these 2021 models ranged between $17 to $136 per MWh during the forecast period (2020 – $6 to $160 per MWh).

22. Other Assets

The components of other assets are as follows:

As at Dec. 31	2021	2020
South Hedland prepaid transmission access and distribution costs	**65**	70
Project development costs	**29**	25
Long-term prepaids and other assets	**48**	59
Loan receivable	**55**	52
Total other assets	**197**	206
Included in the Consolidated Statements of Financial Position as:		
Total current other assets (Note 14)	**55**	—
Total long-term other assets	**142**	206
Total other assets	**197**	206

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.

Project development costs primarily include the project costs for US wind and Australian development projects. Some project costs were written off in 2021 due to the uncertainty on timing of when the projects will proceed (see Note 7).

Long-term prepaids and other assets includes: the funded portion of rail transportation commitments discussed in Note 36(C), the funded portion of the TransAlta Energy Transition Bill commitments discussed in Note 36(G) and other contractually required prepayments and deposits.

The loan receivable relates to the advancement by the Company's subsidiary, Kent Hills Wind LP, of $55 million (2020 – $52 million) which is net of the Kent Hills Wind bond financing proceeds to its 17 per cent partner. The unsecured loan bears interest at 4.55 per cent, with interest payable quarterly, commencing on Dec. 31, 2017 and matures in October 2022; as such, it was moved to current assets (Note 14).

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, 2019	501	45	546
Liabilities incurred	1	34	35
Liabilities settled	(18)	(19)	(37)
Accretion	30	—	30
Acquisition of liabilities	1	—	1
Revisions in estimated cash flows	61	11	72
Revisions in discount rates(1)	36	—	36
Reversals	—	(6)	(6)
Change in foreign exchange rates	(4)	—	(4)
Balance, Dec. 31, 2020	608	65	673
Liabilities incurred	**8**	**22**	**30**
Liabilities settled (Note 36)	**(18)**	**(62)**	**(80)**
Accretion	**32**	**—**	**32**
Acquisition of liabilities	**2**	**—**	**2**
Revisions in estimated cash flows	**167**	**12**	**179**
Revisions in discount rates	**(6)**	**—**	**(6)**
Reversals	**—**	**(3)**	**(3)**
Balance, Dec. 31, 2021	**793**	**34**	**827**

(1) Discount rates at Dec. 31, 2020, are generally lower than those at Dec. 31, 2019, due to decreases in the underlying risk-free US and Canadian benchmark yields and changes in credit spreads due to volatility within the market as a result of COVID-19. On average, these rates decreased by approximately 0.3 to 0.9 per cent.

	Decommissioning and restoration	Other	Total
Balance, Dec. 31, 2020	608	65	673
Current portion	21	38	59
Non-current portion	587	27	614
Balance, Dec. 31, 2021	**793**	**34**	**827**
Current portion	**35**	**13**	**48**
Non-current portion	**758**	**21**	**779**

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 $1.6 billion, which will be incurred between 2022 and 2072. The majority of the costs will be incurred between 2025 and 2050.

In 2021, the Company adjusted the wind assets decommissioning and restoration provision as estimates were updated after the review of a recent engineering study on the decommissioning costs of the wind sites. The Company's current best estimate of the decommissioning and restoration provision increased by $120 million. The change in estimate is unrelated to the tower failure identified in the fourth quarter of 2021. The Company also increased the decommissioning and restoration provision by approximately $47 million for the Sundance and Keephills Units included in the Gas and Energy Transition segments to reflect the change in the timing of the expected reclamation work resulting from asset retirements and change in useful lives. These changes resulted in an increase in the related assets in PP&E.

At Dec. 31, 2021, the Company had provided a surety bond in the amount of US$147 million (2020 – US$147 million) in support of future decommissioning obligations at the Centralia coal mine. At Dec. 31, 2021, the Company had provided letters of credit in the amount of $188 million (2020 – $131 million) in support of future decommissioning obligations at the Highvale mine.

In the fourth quarter of 2020, the Company adjusted the Sarnia decommissioning and restoration provision to reflect an updated engineering study. The Company's current best estimate of the decommissioning and restoration provision decreased by $15 million. This resulted in a decrease in the related assets in PP&E.

In the third quarter of 2020, the Company adjusted the Highvale mine decommissioning and restoration provision to reflect the mine closure advancement, an updated mine plan and current mining activity including increased volume of material movement. The Company's current best estimate of the decommissioning and restoration provision increased by $75 million. This resulted in an increase in the related assets in PP&E.

B. Other Provisions

Other provisions also include provisions arising from ongoing business activities and include amounts related to commercial disputes between the Company and customers or suppliers. 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.

During the third quarter of 2021, an onerous contract provision for future royalty payments of $14 million was recognized as a result of a decision to accelerate the plans to shut down the Highvale mine, with the effect that any remaining future royalty payments related to the extraction of coal has no future economic benefit. Payments required under the royalty contract will continue through 2023. At Dec. 31, 2021, the remaining balance of the provision was $14 million.

During the fourth quarter of 2020, an onerous contract provision of $29 million was recognized as a result of a decision to accelerate plans to eliminate coal as a fuel source at the Sheerness facility by the end of 2021. The last coal shipment was received during the first quarter of 2021, while payments required under the contract will continue until 2025. At Dec. 31, 2021, the remaining balance of the provision was $14 million.

24. Credit Facilities, Long-Term Debt and Lease Liabilities

A. Amounts Outstanding

The amounts outstanding are as follows:

As at Dec. 31				2021			2020		
	Segment	Maturity	Currency	Carrying value	Face value	Interest(1)	Carrying value	Face value	Interest
Credit facilities									
Committed syndicated bank facility(2)	Corporate	2025	CAD	—	—	—%	114	114	2.7%
Debentures									
7.3% Medium term notes	Corporate	2029	CAD	**110**	**110**	**7.3%**	109	110	7.3%
6.9% Medium term notes	Corporate	2030	CAD	**141**	**141**	**6.9%**	140	141	6.9%
Senior notes(3)									
6.5% Senior notes	Corporate	2040	USD	**378**	**383**	**6.5%**	380	383	6.5%
4.5% Senior notes	Corporate	2022	USD	**510**	**511**	**4.5%**	506	511	4.5%
Non-recourse									
Melancthon Wolfe Wind LP bond	Wind & Solar	2028	CAD	**235**	**237**	**3.8%**	268	270	3.8%
New Richmond Wind LP bond	Wind & Solar	2032	CAD	**120**	**121**	**4.0%**	127	128	4.0%
Kent Hills Wind LP bond(4)	Wind & Solar	2033	CAD	**221**	**221**	**4.5%**	230	233	4.5%
Windrise Wind LP bond	Wind & Solar	2041	CAD	**171**	**173**	**3.4%**	—	—	—%
Pingston bond	Hydro	2023	CAD	**45**	**45**	**3.0%**	45	45	3.0%
TAPC Holdings LP bond (Poplar Creek)	Gas	2030	CAD	**102**	**104**	**4.4%**	111	113	4.5%
TEC Hedland PTY Ltd bond(5)	Gas	2042	AUD	**732**	**742**	**4.1%**	772	782	4.1%
TransAlta OCP LP bond	Gas	2030	CAD	**263**	**265**	**4.5%**	284	287	4.5%
Tax equity financing									
Big Level & Antrim(6)	Wind & Solar	2029	USD	**106**	**112**	**6.6%**	112	119	6.6%
Lakeswind(7)	Wind & Solar	2029	USD	**18**	**18**	**10.5%**	22	22	10.5%
North Carolina Solar(8)	Wind & Solar	2028	USD	**11**	**11**	**7.3%**	—	—	—
Other	Corporate	2023	CAD	**4**	**4**	**5.9%**	7	6	5.9%
Total long-term debt				**3,167**	**3,198**		3,227	3,264	
Lease liabilities				**100**			134		
				3,267			3,361		
Less: current portion of long-term debt				**(837)**			(97)		
Less: current portion of lease liabilities				**(7)**			(8)		
Total current long-term debt and lease liabilities				**(844)**			(105)		
Total credit facilities, long-term debt and lease liabilities				**2,423**			3,256		

(1) Interest 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, 2021 — US$700 million (Dec. 31, 2020 — US$700 million).
(4) Kent Hills Wind LP bond is classified as a current liability. Refer to section B - Restrictions Related to Non-Recourse Debt and Other Debt, for more information.
(5) AU face value at Dec. 31, 2021 — AU$800 million related to the TEC offering (2020 — AU$800 million).
(6) US face value at Dec. 31, 2021 — US$88 million (2020 — US$94 million).
(7) US face value at Dec. 31, 2021 — US$14 million (2020 — US$16 million).
(8) US face value at Dec. 31, 2021 — US$9 million (2020 — nil).

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

As at Dec. 31, 2021	Facility size	Utilized: Outstanding letters of credit[1]	Utilized: Actual drawings	Available capacity	Maturity date
TransAlta Corporation					
Committed syndicated bank facility[2]	1,250	618	—	632	Q2 2025
Canadian committed bilateral credit facilities	240	186	—	54	Q2 2023
TransAlta Renewables					
Committed credit facility[2]	700	98	—	602	Q2 2025
Total	**2,190**	**902**	**—**	**1,288**	

(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. At Dec. 31, 2021, TransAlta provided cash collateral of $55 million.
(2) Includes letters of credit issued under the demand facilities for TransAlta and TransAlta Renewables.

The Company has $2 billion (2020 — $2 billion) of committed syndicated bank facilities and $0.2 billion of committed bilateral credit facilities, of which $1.3 billion was available as at Dec. 31, 2021 (2020 — $1.5 billion) and including the undrawn letters of credit are the primary source for short-term liquidity after the cash flow generated from the Company's business. This includes a $1.3 billion credit facility that was converted into a facility with a Sustainability Linked Loan ("SLL") and that was extended to June 30, 2025. The facility's financing terms will align the cost of borrowing to TransAlta's greenhouse gas emission reductions and gender diversity targets, which are part of the Company's overall plan for environment, social and governance. The SLL will have a cumulative pricing adjustment to the borrowing costs on the facilities and a corresponding adjustment to the standby fee (the "Sustainability Adjustment"). Depending on performance against interim targets that have been set for each year of the credit facility term, the Sustainability Adjustment is structured as a two-way mechanism and could move either up, down or remain unchanged for each sustainability performance target based on performance. In addition, the Company's committed bilateral credit facilities were also extended to June 30, 2023. Interest rates on the credit facilities vary depending on the option selected – Canadian prime, bankers' acceptances, USD LIBOR or US base rate – in accordance with a pricing grid that is standard for such facilities.

The Company is in compliance with the terms of the credit facilities and all undrawn amounts are fully available. In addition to the $1.3 billion available under the credit facilities, the Company also has $947 million of available cash and cash equivalents and $17 million ($17 million principal portion) in cash restricted for repayment of the OCP bonds (refer to section E below).

TransAlta has letters of credit of $157 million issued from uncommitted demand facilities; these obligations are backstopped and reduce the available capacity on the committed credit facilities.

Debentures
On Nov. 25, 2020, the Company redeemed $400 million of its then due 5.0 per cent medium term notes.

Senior notes
A total of US$370 million (2020 — US$370 million) of the senior notes has been designated as a hedge of the Company’s net investment in US foreign operations.

Non-recourse debt
On Dec. 6, 2021, TransAlta completed a secured green bond offering by way of private placement for approximately $173 million (the "Offering"). The Offering is secured by a first ranking charge over all assets of the issuer, Windrise Wind LP, and the bonds amortize and bear interest from their date of issue at a rate of 3.41 per cent per annum and mature on Sept. 30, 2041. Payments on the bonds will be interest-only to and including Dec. 31, 2022, with quarterly blended payments of principal and interest commencing on March 31, 2023. TransAlta intends to use proceeds of the Offering to finance or refinance eligible green projects, including renewable energy facilities and to fund a construction reserve account.

On Oct. 22, 2020, TEC closed an AU$800 million senior secured note offering, by way of a private placement, which is secured by, among other things, a first ranking charge over all assets of TEC. The notes bear interest at 4.07 per cent per annum, payable quarterly and matures on June 30, 2042, with principal payments starting on March 31, 2022. Funds were used to repay indebtedness on the credit facility and to fund future growth opportunities within TransAlta Renewables. The TEC Offering has a rating of BBB by Kroll Bond Rating Agency.

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 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 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 - on March 31, 2030, 10 years from commercial operation of the projects; Lakeswind - March 31, 2029, and North Carolina Solar on Dec. 31, 2028.

Other

Other debt consists of an unsecured commercial loan obligation that bears interest at 5.9 per cent and matures in 2023, requiring annual payments of interest and principal.

TransAlta's debt has terms and conditions, including financial covenants, that are considered normal and customary. As at Dec. 31, 2021, the Company was in compliance with all debt covenants except the Kent Hills non-recourse bond as discussed below.

B. Restrictions Related to Non-Recourse Debt and Other Debt

The Melancthon Wolfe Wind LP, Pingston, TAPC Holdings LP, New Richmond Wind LP, Kent Hills Wind LP, TEC Hedland Pty Ltd notes, Windrise Wind LP and TransAlta OCP LP non-recourse bonds with a carrying value of $1.9 billion as at Dec. 31, 2021 (Dec. 31, 2020 — $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 2021, except the Kent Hills non-recourse bond as discussed below. However, 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 2022. At Dec. 31, 2021, $67 million (Dec. 31, 2020 —$73 million) of cash was subject to these financial restrictions. At Dec. 31, 2021, Kent Hills cash in the amount of $6 million is not able to be distributed or accessed by other corporate entities, as discussed below.

Proceeds received from the TEC Notes in the amount of $3 million (AU$4 million) 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.

As a result of the determination that all 50 foundations require replacement, as well as certain resulting amendments to applicable insurance policies, the Company has provided notice to BNY Trust Company of Canada, as trustee (the "Trustee"), for the approximately $221 million outstanding non-recourse project bonds (the "KH Bonds") secured by, among other things, the Kent Hills 1, 2 and 3 wind sites, that events of default may have occurred under the trust indenture governing the terms of the KH Bonds. Upon the occurrence of any event of default, holders of more than 50 per cent of the outstanding principal amount of the KH Bonds have the right to direct the Trustee to declare the principal and interest on the KH Bonds and all other amounts due, together with any make-whole amount (Dec. 31, 2021 — $39 million), to be immediately due and payable and to direct the Trustee to exercise rights against certain collateral. The Company is in discussions with the Trustee and holders of the Kent Hills bonds to negotiate required waivers and amendments while the Company works to remedy the matters described in the notice. Although the Company expects that it will reach agreement with the Trustee and holders of the KH Bonds with respect to terms of an acceptable waiver and amendment, there can be no assurance that the Company will receive such waivers and amendments. Accordingly, the Company has classified the entire carrying value of the KH Bonds as a current liability as at Dec. 31, 2021.

C. Security

Non-recourse debts totalling $1.5 billion as at Dec. 31, 2021 (Dec. 31, 2020 — $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, 2021 (Dec. 31, 2020 — $1 billion) and intangible assets with total carrying amounts of $78 million (Dec. 31, 2020 — $88 million). At Dec. 31, 2021, a non-recourse bond of approximately $103 million (Dec. 31, 2020 — $111 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 $263 million (Dec. 31, 2020 — $285 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

	2022[1]	2023	2024	2025	2026	2027 and thereafter	Total
Principal repayments[2]	836	155	113	127	127	1,840	**3,198**
Lease liabilities[3]	(6)	4	3	3	3	93	**100**

(1) Includes the Kent Hills Wind LP non-recourse bonds. The successful receipt of waivers and amendments would extend principal repayments beyond 2022.
(2) Excludes impact of hedge accounting and derivatives.
(3) Lease liabilities include a lease incentive of $13 million, expected to be received in 2022.

E. Restricted Cash

At Dec. 31, 2021, the Company had nil (Dec. 31, 2020 – $9 million) in restricted cash related to the Big Level tax equity financing that is held in a construction reserve account. The proceeds were released from the construction reserve account in 2021.

The Company had $17 million (Dec. 31, 2020 – $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 the next scheduled debt repayment in February 2022.

The Company also had $53 million (Dec. 31, 2020 – $45 million) of restricted cash related to the TEC Notes; reserves are required to be held under TEC commercial arrangements and for debt service. Cash reserves may be replaced by letters of credit in the future.

F. Letters of Credit

Letters of credit issued by TransAlta are drawn on its committed syndicated credit facility, its $240 million bilateral committed credit facilities and its two uncommitted $150 million and $100 million demand letters of credit facilities. Letters of credit issued by TransAlta Renewables are drawn on its uncommitted $150 million demand letter of credit facility.

Letters of credit are issued to counterparties under 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. Any amounts owed by the Company or its subsidiaries under these contracts are reflected in the Consolidated Statements of Financial Position. 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, 2021, was $902 million (2020 – $621 million) with no (2020 – nil) amounts exercised by third parties under these arrangements.

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").

Upon entering into the Investment Agreement and as required under the terms of the agreement, the Company paid Brookfield a $7.5 million structuring fee. A commitment fee of $15 million was also paid upon completion of the initial funding. These transaction costs, representing three per cent of the total investment of $750 million, have been recognized as part of the carrying value of the unsecured subordinated debentures.

On May 1, 2019, Brookfield invested the initial tranche of $350 million in exchange for seven per cent unsecured subordinated debentures due May 1, 2039. On Oct. 30, 2020, Brookfield invested the second tranche of $400 million in exchange for redeemable, retractable first preferred shares.

A. $750 million Exchangeable Securities

As at	Dec. 31, 2021			Dec. 31, 2020		
	Carrying value	Face value	Interest	Carrying value	Face value	Interest
Exchangeable debentures – due May 1, 2039	**335**	**350**	**7%**	330	350	7%
Exchangeable preferred shares[1]	**400**	**400**	**7%**	400	400	7%
Total long-term debt	**735**	**750**		730	750	

(1) Exchangeable preferred share dividends are reported as interest expense.

On Dec. 13, 2021, the Company declared a dividend of $7 million in aggregate for Exchangeable Preferred Shares at the fixed rate of 1.764 per cent, per share payable on Feb. 28, 2022. The Exchangeable Preferred Shares are considered debt for accounting purposes, and as such, dividends are reported as interest expense (Note 11).

B. Option to Exchange

As at	Dec. 31, 2021		Dec. 31, 2020	
Description	**Base fair value**	**Sensitivity**	**Base fair value**	**Sensitivity**
Option to exchange – embedded derivative	**—**	**+nil -32**	—	+nil -33

The Investment Agreement allows Brookfield the option, after Dec. 31, 2024, to exchange all of the outstanding exchangeable securities 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 1 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, and 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.

Under the terms of the Investment Agreement, Brookfield committed to purchase TransAlta common shares on the open market to increase its share ownership in TransAlta to not less than nine per cent by May 1, 2021. As of Dec. 31, 2021, Brookfield, through its affiliates, held, owned or had control over an aggregate of 35,425,696 common shares, representing approximately 13.1 per cent of the issued and outstanding common shares, calculated on an undiluted basis. 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	**2021**	2020
Defined benefit obligation (Note 31)	**228**	282
Long-term incentive accruals (Note 30)	**4**	4
Other	**21**	12
Total	**253**	298

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. As a result of increases in discount rates in 2021, largely driven by increases in market benchmark rates, the defined benefit obligation has decreased by $54 million to $228 million as at Dec. 31, 2021, from $282 million as at Dec. 31, 2020.

27. Common Shares

A. Issued and Outstanding

TransAlta is authorized to issue an unlimited number of voting common shares without nominal or par value.

As at Dec. 31	**2021**		2020	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of year	**269.8**	**2,896**	277.0	2,978
Purchased and cancelled under the NCIB	**—**	**—**	(7.3)	(79)
Effects of share-based payment plans	**—**	**(3)**	—	(3)
Stock options exercised	**1.2**	**8**	0.1	—
Issued and outstanding, end of year	**271.0**	**2,901**	269.8	2,896

B. Normal course issuer bid ("NCIB") Program

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.

The following are the effects of the Company's purchase and cancellation of the common shares during the year:

For the year ended Dec. 31	**2021**	2020
Total shares purchased(1)	**—**	7,352,600
Average purchase price per share	**—**	$8.33
Total cost	**—**	61
Weighted average book value of shares cancelled	**—**	79
Amount recorded in deficit	**—**	18

(1) As at Dec. 31, 2021, includes nil (2020 — 456,200) shares that were repurchased but were not cancelled due to timing differences between the transaction date and settlement date.

2021

On May 25, 2021, the Toronto Stock Exchange ("TSX") accepted the notice filed by the Company to implement an NCIB for a portion of our common shares. Pursuant to the NCIB, TransAlta may repurchase up to a maximum of 14,000,000 common shares, representing approximately 7.16 per cent of its public float of common shares as at May 18, 2021. 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, 2021 and ends on May 30, 2022, 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. No common shares have been repurchased under the current and previous NCIB in 2021.

2020

On May 26, 2020, the Company announced that the TSX accepted the notice filed by the Company to implement an NCIB for a portion of its common shares. Pursuant to the NCIB, the Company was permitted to purchase up to a maximum of 14,000,000 common shares, representing approximately 7.02 per cent of its issued and common shares as at May 25, 2020.

C. Shareholder Rights Plan

The Company initially adopted the Shareholder Rights Plan in 1992, which was amended and restated on April 26, 2019, to reflect current market practice and to reflect changes to the take-over bid regime. 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 26, 2019, and will need to be approved at the annual meeting of shareholders in 2022. 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	**2021**	2020	2019
Net earnings (loss) attributable to common shareholders	**(576)**	(336)	52
Basic and diluted weighted average number of common shares outstanding (millions)	**271**	275	283
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(2.13)**	(1.22)	0.18

E. Dividends

On Dec. 13, 2021, the Company declared a quarterly dividend of $0.05 per common share, payable on April 1, 2022.

There have been no other 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	2021		2020	
Series	Number of shares *(millions)*	Amount	Number of shares *(millions)*	Amount
Series A	**9.6**	**235**	10.2	248
Series B	**2.4**	**58**	1.8	45
Series C	**11.0**	**269**	11.0	269
Series E	**9.0**	**219**	9.0	219
Series G	**6.6**	**161**	6.6	161
Issued and outstanding, end of year	**38.6**	**942**	38.6	942

I. Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares Conversion

On March 18, 2021, the Company announced that 1,417,338 of its 10.2 million Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares ("Series A Shares") and 871,871 of its 1.8 million Series B Cumulative Redeemable Floating Rate Preferred Shares ("Series B Shares") were tendered for conversion, on a one-for-one basis, into Series B Shares and Series A Shares, respectively after having taken into account all election notices. As a result of the conversion, the Company had 9.6 million Series A Shares and 2.4 million Series B Shares issued and outstanding at March 31, 2021.

II. Preferred Share Series Information

The holders are entitled to receive cumulative fixed quarterly cash dividends at a specified rate, 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, 2021, are as follows:

Series	Rate during term	Annual dividend rate per share *($)*	Next conversion date	Rate spread over benchmark *(per cent)*	Convertible to Series
A	Fixed	0.71924	March 31, 2026	2.03	B
B	Floating	0.53866	March 31, 2026	2.03	A
C	Fixed	1.00676	June 30, 2022	3.10	D
D	Floating	—	—	3.10	C
E	Fixed	1.29852	Sept. 30, 2022	3.65	F
F	Floating	—	—	3.65	E
G	Fixed	1.24700	Sept. 30, 2024	3.80	H
H	Floating	—	—	3.80	G

B. Dividends

The following table summarizes the value of the preferred share dividends declared in 2021 and 2020:

	Total dividends declared	
Series	**2021**(1)	2020
A	**7**	9
B(2)	**1**	1
C	**11**	14
E	**12**	15
G	**8**	10
Total for the year	**39**	49

(1) No dividends were declared in the first quarter of 2021 as the quarterly dividend related to the period covering the first quarter of 2021 was declared in December 2020.
(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.

On Dec. 13, 2021, the Company declared a quarterly dividend of $0.1798 per share on the Series A preferred shares, $0.1331 per share on the Series B preferred shares, $0.2517 per share on the Series C preferred shares, $0.3246 per share on the Series E preferred shares, and $0.3118 per share on the Series G preferred shares, all payable on March 31, 2022.

29. Accumulated Other Comprehensive Earnings

The components of, and changes in, accumulated other comprehensive earnings are as follows:

	2021	2020
Currency translation adjustment		
Opening balance, Jan. 1	**(21)**	(21)
Losses on translating net assets of foreign operations, net of reclassifications to net earnings, net of tax	**(14)**	(11)
Gains on financial instruments designated as hedges of foreign operations, net of reclassifications to net earnings, net of tax	**—**	11
Balance, Dec. 31	**(35)**	(21)
Cash flow hedges		
Opening balance, Jan. 1	**436**	527
Losses on derivatives designated as cash flow hedges, net of reclassifications to net earnings and to non-financial assets, net of tax(1)	**(208)**	(91)
Balance, Dec. 31	**228**	436
Employee future benefits		
Opening balance, Jan. 1	**(66)**	(55)
Net actuarial gains (losses) on defined benefit plans, net of tax(2)	**37**	(11)
Balance, Dec. 31	**(29)**	(66)
Other		
Opening balance, Jan. 1	**(47)**	3
Intercompany investments at FVOCI	**29**	(50)
Balance, Dec. 31	**(18)**	(47)
Accumulated other comprehensive earnings	**146**	302

(1) Net of income tax of $57 million for the year ended Dec. 31, 2021 (2020 – $23 million).
(2) Net of income tax of $11 million for the year ended Dec. 31, 2021 (2020 – $3 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 PSU and RSU Plan, grants 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 two to three 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 2021 was $14 million (2020 – $15 million, 2019 – $19 million), which is included in operations, maintenance and administration expense in the Consolidated Statements of Earnings (Loss).

B. Deferred Share Unit ("DSU") Plan

Under the DSU 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 $3 million in 2021 (2020 – $1 million, 2019 – $2 million).

C. Stock Option Plans

On May 4, 2021, the Company approved amendments to the Stock Option Plan to reduce the total aggregate number of common shares held in reserve for issuance under this program. The amendments reduce the aggregate total number of shares reserved for issuance to 14.5 million common shares as at March 31, 2021 (Dec. 31, 2020 — 16.5 million common shares). The Company is authorized to grant options to purchase up to an aggregate of 14.5 million common shares at prices based on the market price of the shares on the TSX as determined on the grant date. The plan provides for grants of options to all full-time employees, including executives, designated by the Human Resources Committee from time to time.

In 2021, the Company granted executive officers of the Company a total of 0.7 million stock options with a weighted average exercise price of $9.86 that vest after a three-year period and expire seven years after issuance (2020 — 0.7 million stock options at $9.17; 2019 — 1.4 million stock options at $5.65). The expense recognized relating to these grants during 2021 was approximately $2 million (2020 — approximately $2 million, 2019 — approximately $1 million).

The total options outstanding and exercisable under these stock option plans at Dec. 31, 2021, 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 - 9.00	**3.2**	**4.2**	**7.54**

(1) Options currently exercisable as at Dec. 31, 2021.

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, 2021. The latest actuarial valuation for accounting purposes of the Highvale and Canadian pension plans was at Dec. 31, 2019. 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, 2021.

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 2021 for the amount of $97 million to secure the obligations under the supplemental plan.

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, 2019, and Jan. 1, 2021, respectively. The measurement date used to determine the present value obligation for both plans was Dec. 31, 2021.

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 5 per cent to 10 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, 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**

Year ended Dec. 31, 2020	Registered	Supplemental	Other	Total
Current service cost	5	2	1	8
Administration expenses	1	—	—	1
Interest cost on defined benefit obligation	16	3	1	20
Interest on plan assets	(11)	(1)	—	(12)
Curtailment and amendment gain	(2)	—	—	(2)
Defined benefit expense	9	4	2	15
Defined contribution expense	9	—	—	9
Net expense	18	4	2	24

Year ended Dec. 31, 2019	Registered	Supplemental	Other	Total
Current service cost	7	2	1	10
Administration expenses	2	—	—	2
Interest cost on defined benefit obligation	19	3	1	23
Interest on plan assets	(12)	(1)	—	(13)
Curtailment and amendment gain	(3)	—	—	(3)
Defined benefit expense	13	4	2	19
Defined contribution expense	9	—	—	9
Net expense	22	4	2	28

C. Status of Plans

The status of the defined benefit pension and other post-employment benefit plans is as follows:

Year ended Dec. 31, 2021	**Registered**	**Supplemental**	**Other**	**Total**
Fair value of plan assets	**339**	**14**	**—**	**353**
Present value of defined benefit obligation	**(469)**	**(101)**	**(23)**	**(593)**
Funded status – plan deficit	**(130)**	**(87)**	**(23)**	**(240)**
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	**(4)**	**(6)**	**(2)**	**(12)**
Other long-term liabilities	**(126)**	**(81)**	**(21)**	**(228)**
Total amount recognized	**(130)**	**(87)**	**(23)**	**(240)**

Year ended Dec. 31, 2020	Registered	Supplemental	Other	Total
Fair value of plan assets	367	14	—	381
Present value of defined benefit obligation	(542)	(109)	(24)	(675)
Funded status – plan deficit	(175)	(95)	(24)	(294)
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	(5)	(5)	(2)	(12)
Other long-term liabilities	(170)	(90)	(22)	(282)
Total amount recognized	(175)	(95)	(24)	(294)

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, 2019	373	13	—	386
Interest on plan assets	11	1	—	12
Net return on plan assets	25	(1)	—	24
Contributions	6	6	1	13
Benefits paid	(45)	(5)	(1)	(51)
Administration expenses	(1)	—	—	(1)
Effect of translation on US plans	(2)	—	—	(2)
As at Dec. 31, 2020	367	14	—	381
Interest on plan assets	**8**	**—**	**—**	**8**
Net return on plan assets	**14**	**(1)**	**—**	**13**
Contributions	**5**	**6**	**1**	**12**
Benefits paid	**(54)**	**(5)**	**(1)**	**(60)**
Administration expenses	**(1)**	**—**	**—**	**(1)**
As at Dec. 31, 2021	**339**	**14**	**—**	**353**

The fair value of the Company's defined benefit plan assets by major category is as follows:

Year ended Dec. 31, 2021	**Level I**	**Level II**	**Level III**	**Total**
Equity securities				
Canadian	**–**	**29**	**4**	**33**
US	**–**	**20**	**–**	**20**
International	**47**	**79**	**–**	**126**
Private	**–**	**–**	**1**	**1**
Bonds				
AAA	**–**	**28**	**–**	**28**
AA	**–**	**54**	**–**	**54**
A	**–**	**36**	**–**	**36**
BBB	**1**	**24**	**–**	**25**
Below BBB	**–**	**10**	**–**	**10**
Money market and cash and cash equivalents	**–**	**20**	**–**	**20**
Total	**48**	**300**	**5**	**353**

Year ended Dec. 31, 2020	Level I	Level II	Level III	Total
Equity securities				
Canadian	–	64	–	64
US	–	30	–	30
International	–	103	–	103
Private	–	–	1	1
Bonds				
AAA	–	36	–	36
AA	–	67	–	67
A	–	34	–	34
BBB	1	22	–	23
Below BBB	–	4	–	4
Money market and cash and cash equivalents	–	19	–	19
Total	1	379	1	381

Plan assets do not include any common shares of the Company at Dec. 31, 2021 and Dec. 31, 2020. The Company charged the registered plan nil for administrative services provided for the year ended Dec. 31, 2021 (2020 – nil).

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, 2019	543	99	22	664
Current service cost	5	2	1	8
Interest cost	16	3	1	20
Benefits paid	(45)	(5)	(1)	(51)
Curtailment	(2)	—	—	(2)
Actuarial loss arising from financial assumptions	43	10	2	55
Actuarial gain arising from experience adjustments	(17)	—	—	(17)
Effect of translation on US plans	(1)	—	(1)	(2)
Present value of defined benefit obligation as at Dec. 31, 2020	542	109	24	675
Current service cost	**3**	**2**	**1**	**6**
Interest cost	**12**	**2**	**—**	**14**
Benefits paid	**(54)**	**(5)**	**(1)**	**(60)**
Curtailment	**(7)**	**—**	**—**	**(7)**
Actuarial gain arising from financial assumptions	**(26)**	**(7)**	**(1)**	**(34)**
Actuarial gain arising from experience adjustments	**(1)**	**—**	**—**	**(1)**
Present value of defined benefit obligation as at Dec. 31, 2021	**469**	**101**	**23**	**593**

The weighted average duration of the defined benefit plan obligation as at Dec. 31, 2021, is 13.6 years.

F. Contributions

The expected employer contributions for 2022 for the defined benefit pension and other post-employment benefit plans are as follows:

	Registered	Supplemental	Other	Total
Expected employer contributions	**5**	**6**	**2**	**13**

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:

	As at Dec. 31, 2021			As at Dec. 31, 2020		
(per cent)	**Registered**	**Supplemental**	**Other**	Registered	Supplemental	Other
Accrued benefit obligation						
Discount rate	**2.8**	**2.8**	**2.7**	2.4	2.3	2.3
Rate of compensation increase	**2.9**	**3.0**	**—**	2.9	3.0	—
Assumed health-care cost trend rate						
Health-care cost escalation(1)(3)	**—**	**—**	**6.8**	—	—	6.8
Dental-care cost escalation	**—**	**—**	**4.0**	—	—	4.0
Benefit cost for the year						
Discount rate	**2.4**	**2.3**	**2.3**	3.0	3.0	3.0
Rate of compensation increase	**2.9**	**3.0**	**—**	2.9	3.0	—
Assumed health-care cost trend rate						
Health-care cost escalation(2)(4)	**—**	**—**	**7.1**	—	—	7.1
Dental-care cost escalation	**—**	**—**	**4.0**	—	—	4.0

(1) 2021 Post- and pre-65 rates: decreasing gradually to 4.5% by 2029 and remaining at that level thereafter for the US and decreasing gradually by 0.3% per year to 4.5% in 2030 for Canada.
(2) 2021 Post- and pre-65 rates: decreasing gradually to 4.5% by 2029 and remaining at that level thereafter for the US and decreasing gradually by 0.3% per year to 4.5% in 2030 for Canada.
(3) 2020 Post- and pre-65 rates: decreasing gradually to 4.5% by 2029 and remaining at that level thereafter for the US and decreasing gradually by 0.3% per year to 4.5% in 2030 for Canada.
(4) 2020 Post- and pre-65 rates: decreasing gradually to 4.5% by 2029 and remaining at that level thereafter for the US and decreasing gradually by 0.3% per year to 4.5% 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**	
Year ended Dec. 31, 2021	**Registered**	**Supplemental**	**Other**	**Pension**	**Other**
1% decrease in the discount rate	**61**	**15**	**2**	**3**	**1**
1% increase in the salary scale	**3**	**—**	**—**	**—**	**—**
1% increase in the health-care cost trend rate	**—**	**—**	**2**	**—**	**—**
10% improvement in mortality rates	**20**	**4**	**—**	**1**	**—**

32. Joint Arrangements

Joint arrangements at Dec. 31, 2021, 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

33. Cash Flow Information

A. Change in Non-Cash Operating Working Capital

Year ended Dec. 31	**2021**	2020	2019
(Use) source:			
Accounts receivable	**(28)**	(79)	261
Prepaid expenses	**9**	2	—
Income taxes receivable	**—**	(4)	(6)
Inventory	**42**	6	(13)
Accounts payable, accrued liabilities and provisions	**153**	160	(130)
Income taxes payable	**(2)**	4	9
Change in non-cash operating working capital	**174**	89	121

B. Changes in Liabilities from Financing Activities

	Balance Dec. 31, 2020	**Cash issuances**	**Repayments and dividends paid**	**New leases**	**Dividends declared**	**Foreign exchange impact**	**Other**	**Balance Dec. 31, 2021**
Long-term debt and lease liabilities	3,361	**173**	**(214)**	**1**	**—**	**(39)**	**(15)**	**3,267**
Exchangeable securities	730	**—**	**—**	**—**	**—**	**—**	**5**	**735**
Dividends payable (common and preferred)	59	**—**	**(87)**	**—**	**90**	**—**	**—**	**62**
Total liabilities from financing activities	4,150	**173**	**(301)**	**1**	**90**	**(39)**	**(10)**	**4,064**

	Balance Dec. 31, 2019	Cash issuances	Repayments and dividends paid	New leases	Dividends declared	Foreign exchange impact	Other	Balance Dec. 31, 2020
Long-term debt and lease liabilities	3,212	753	(620)	16	—	5	(5)	3,361
Exchangeable securities	326	400	—	—	—	—	4	730
Dividends payable (common and preferred)	37	—	(86)	—	107	—	1	59
Total liabilities from financing activities	3,575	1,153	(706)	16	107	5	—	4,150

34. Capital

TransAlta's capital is comprised of the following:

As at Dec. 31	2021	2020	Increase/ (decrease)
Long-term debt[1]	**3,267**	3,361	**(94)**
Exchangeable securities	**735**	730	**5**
Equity			
Common shares	**2,901**	2,896	**5**
Preferred shares	**942**	942	**—**
Contributed surplus	**46**	38	**8**
Deficit	**(2,453)**	(1,826)	**(627)**
Accumulated other comprehensive earnings	**146**	302	**(156)**
Non-controlling interests	**1,011**	1,084	**(73)**
Less: available cash and cash equivalents[2]	**(947)**	(703)	**(244)**
Less: principal portion of restricted cash on TransAlta OCP bonds[3]	**(17)**	(11)	**(6)**
Less: fair value asset of hedging instruments on long-term debt[4]	**(2)**	(2)	**—**
Total capital	**5,629**	6,811	**(1,182)**

(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 internally and evaluated by management using a net debt position. In this regard, 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 because 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 its 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 DBRS (stable outlook). During 2021, Moody's reaffirmed its issuer rating of Ba1 with a stable outlook; DBRS reaffirmed the Company's Unsecured Debt rating and Medium-Term Notes rating of BBB (low), the Preferred Shares rating of Pfd-3 (low) and Issuer Rating of BBB (low) with a stable outlook; and Standard and Poor's reaffirmed the Company's Unsecured Debt rating and Issuer 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, 2021 and 2020, 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 is available to fund operations, pay dividends, distribute payments to subsidiaries' non-controlling interests and invest in PP&E.

Year ended Dec. 31	2021	2020	Increase (decrease)
Cash flow from operating activities	**1,001**	702	**299**
Change in non-cash working capital	**(174)**	(89)	**(85)**
Cash flow from operations before changes in working capital	**827**	613	**214**
Dividends paid on common shares	**(48)**	(47)	**(1)**
Dividends paid on preferred shares	**(39)**	(39)	**—**
Distributions paid to subsidiaries' non-controlling interests	**(156)**	(97)	**(59)**
Property, plant and equipment expenditures	**(480)**	(486)	**6**
Inflow (outflow)	**104**	(56)	**160**

TransAlta maintains sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business. At Dec. 31, 2021, $1.3 billion (2020 – $1.5 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 to 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, 2021, 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	60.1	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
EMG International, LLC	US	30	Wastewater treatment and biogas fuel to generate electricity

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") and 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	2021	2020	2019
Total compensation	**30**	27	30
Comprised of:			
Short-term employee benefits	**14**	12	13
Post-employment benefits	**1**	2	2
Termination benefits	**—**	—	2
Share-based payments	**15**	13	13

B. TransAlta Renewables Acquisitions

North Carolina Solar

On Nov. 5, 2021, TransAlta completed the sale of a 100 per cent economic interest in the 122 MW portfolio of solar facilities in North Carolina for US$102 million. Pursuant to the transaction, a TransAlta subsidiary owns North Carolina Solar directly and another subsidiary issued tracking preferred shares to TransAlta Renewables reflecting the economic interest in the facilities.

Ada and Skookumchuck

On April 1, 2021, the Company completed the sale of its 100 per cent economic interest in the 29 MW Ada cogeneration facility and its 49 per cent economic interest in the 137 MW Skookumchuck wind facility to TransAlta Renewables for $43 million and $103 million, respectively. Pursuant to the transaction, a TransAlta subsidiary owns Ada and Skookumchuck directly and another subsidiary issued tracking preferred shares to TransAlta Renewables reflecting the economic interest in the facilities.

Big Level and Antrim

During 2021, TransAlta Renewables subscribed for additional tracking preferred shares in Big Level and Antrim for $7 million (US$6 million). In addition, TransAlta Renewables repaid a portion of the total outstanding promissory notes to the Company related to the Big Level and Antrim wind facilities in the amount of $18 million (US$14 million).

Windrise Wind

On Dec. 23, 2020, TransAlta announced that it had entered into definitive agreements for the acquisition by TransAlta Renewables, a subsidiary of the Company, of its 100 per cent direct interest in the 206 MW Windrise wind project located in the Municipal District of Willow Creek, Alberta. On Feb. 26, 2021, TransAlta completed the sale of its 100 per cent direct interest in the 206 MW Windrise wind project to TransAlta Renewables, for $213 million.

WindCharger

On Aug. 1, 2020, the WindCharger battery storage project was sold to TransAlta Renewables for $12 million.

TEC Offering

In relation to the TEC Offering, TransAlta Renewables has received $480 million (AU$515 million) of the proceeds through the redemption of certain intercompany structures. An additional AU$200 million has been loaned to TransAlta Renewables by TransAlta Energy (Australia) Pty Ltd., which is a subsidiary of TransAlta. The loan bears interest at 4.32 per cent and will be repaid by Oct. 23, 2022, or on demand. The remaining proceeds from the TEC Offering were set aside for required reserves and transaction costs. TransAlta Renewables used a portion of the proceeds from the redemption and the intercompany loan to repay existing indebtedness on its credit facility and to acquire the asset and economic interests noted above.

36. Commitments and Contingencies

In addition to commitments disclosed elsewhere in the financial statements, the Company has incurred the following additional contractual commitments, either directly or through its interests in joint operations. Approximate future payments under these agreements are as follows:

	2022	2023	2024	2025	2026	2027 and thereafter	Total
Natural gas, transportation and other contracts	47	54	45	44	45	508	**743**
Transmission	9	9	6	6	2	—	**32**
Coal supply and mining agreements[1]	76	98	90	75	—	—	**339**
Long-term service agreements	89	46	43	32	25	54	**289**
Operating leases	4	3	3	1	1	31	**43**
Growth	941	276	—	—	—	—	**1,217**
TransAlta Energy Transition Bill	6	6	—	—	—	—	**12**
Total	**1,172**	**492**	**187**	**158**	**73**	**593**	**2,675**

(1) Relates to coal supply and mining agreements for Centralia Unit 2.

A. Natural Gas, Transportation and Other Contracts

The Company has fixed price or volume natural gas purchase and transportation contracts. Upon closing of the sale of the Pioneer Pipeline, additional 15-year natural gas transportation agreements for 275 terajoules ("TJ") per day on a firm basis by 2023 arose, bringing the total firm natural gas transportation to 400 TJ per day. Additionally, on June 30, 2021, the Company's agreement to purchase 139 TJ per day of natural gas from Tidewater Midstream & Infrastructure Ltd. was terminated and the commitment related to commodity dispatching was discharged, resulting in a reduction to the commitments disclosed at Dec. 31, 2020, by approximately $1.3 billion.

B. Transmission

The Company has several agreements to purchase transmission network capacity in Canada and 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.

C. Coal Supply and Mining 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. Pricing is reflective of current market conditions.

Commitments related to mining agreements for the Company’s share of its Sheerness joint operation have been reduced due to the accelerated plans to eliminate coal as a fuel source at the Sheerness facility. Amounts due under the contract and a mining royalty agreement for the Highvale mine have been recognized as onerous contract provisions, with the result that no amounts are included as future commitments. For additional information refer to Note 9.

D. 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, coal facilities, equipment for coal and gas, and turbines at various wind facilities.

E. 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.

F. Growth

Commitments for growth relate to the following projects: White Rock Wind Projects, Garden Plain wind project, Horizon Hill wind project and the Northern Goldfields Solar Project.

G. TransAlta Energy Transition Bill Commitments

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 has 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 the termination and certain circumstances, this funding or portion thereof would no longer be required. As of Dec. 31, 2021, the Company has funded approximately US$46 million of the commitment, which is recognized in other assets in the Consolidated Statements of Financial Position.

H. 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.

I. Transmission Line Loss Rule Proceeding
The Company has been participating in a line loss rule proceeding before the AUC. The AUC determined that it has the ability to retroactively adjust line loss charges going back to 2006 and directed the AESO to recalculate loss factors for 2006 to 2016. The AUC approved an invoice settlement process and all three planned settlements have been received. The first two invoices were settled by the first quarter of 2021 and the third invoice settled in the second quarter of 2021. The true-up invoices issued by the AESO in the fourth quarter of 2021 were settled by Dec. 31, 2021, with no further invoices expected.

II. Fortescue Metals Group Ltd. ("FMG") at South Hedland Power Station
On May 2, 2021, the Company entered into a conditional settlement with FMG. The settlement was concluded and the actions were formally dismissed in the Supreme Court of Western Australia on Dec. 7, 2021. The settlement amount has been recorded as revenue in the fourth quarter of 2021, while all other balances previously provided for have been reversed. The settlement has resulted in FMG continuing as a customer of the South Hedland facility.

III. Mangrove Claim
On April 23, 2019, the Mangrove Partners Master Fund Ltd. ("Mangrove") commenced an action in the Ontario Superior Court of Justice naming the Company, the incumbent members of the Board of the Company on such date, and Brookfield as defendants. Mangrove was seeking to set aside the 2019 Brookfield transaction. The parties reached a confidential settlement and the action was discontinued in the Ontario Superior Court of Justice on April 30, 2021.

IV. Keephills 1 Stator Force Majeure
The Balancing Pool and ENMAX Energy Corporation ("ENMAX")are seeking to set aside an arbitration award on the basis that they did not receive a fair hearing. The Alberta Court of Queen's Bench ("ABQB") dismissed the Balancing Pool and ENMAX's allegations of unfairness on June 26, 2019. The Balancing Pool and ENMAX, however, sought leave to appeal the ABQB's decision at the Court of Appeal, which was granted on Feb. 13, 2020. The appeal was heard on July 8, 2021. After the hearing, counsel for ENMAX raised concerns that one of the three justices on the appeal panel was distracted during the hearing. The justice has since recused herself from the hearing and the parties made submissions with respect to whether the remaining two justices can continue to issue the decision or whether a new hearing is required. On Nov. 8, 2021, the Alberta Court of Appeal released its decision and ordered that the appeal be re-heard by a new three-person panel of the Court of Appeal, which was heard on Jan. 27, 2022. TransAlta remains of the view that the Court of Appeal will affirm the ABQB decision that the arbitration proceeding was fair.

V. Keephills 1 Superheater Force Majeure
Keephills Unit 1 was taken offline from March 17, 2015, to May 17, 2015, as a result of a large leak in the secondary superheater. TransAlta claimed force majeure under the Alberta PPA. ENMAX, the purchaser under the Alberta PPA at the time, did not dispute the force majeure but the Balancing Pool attempted to do so, seeking to recover $12 million in capacity payment charges it paid to TransAlta while the unit was offline. The parties reached a confidential settlement on April 21, 2021, and this matter is now resolved.

VI. Sundance A Decommissioning
TransAlta filed an application with the AUC 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. Due to various factors, including the COVID-19 pandemic and significant information requests from the Balancing Pool, the application has been delayed. While a hearing date has not been set, the application will likely be heard in late 2022 or early 2023. TransAlta expects to receive payment from the Balancing Pool for its decommissioning costs; however, the amount that the AUC will award is uncertain.

VII. Hydro Power Purchase Arrangement ("Hydro PPA") Emission Performance Credits
The Balancing Pool claims to be entitled to emission performance credits ("EPCs") earned by the Hydro facilities as a result of opting those facilities into the *Carbon Competitiveness Incentive Regulation* from 2018-2020 inclusive. The Balancing Pool claims ownership of the EPCs because it believes the change-in-law provisions under the Hydro PPA require the EPCs to be passed through to the Balancing Pool. TransAlta has not received any benefit from the EPCs or from any purported change in law and believes that the Balancing Pool has no rights to these credits. An arbitration has commenced, and the hearing is scheduled for Feb. 6-10, 2023.

VIII. Direct Assigned Capital Deferral Account ("DACDA") Application

AltaLink Management Ltd. ("AltaLink") and TransAlta (as a secondary applicant) filed an application before the AUC to recover its 2016-2018 DACDA costs incurred for the 240 kV line upgrades for the Edmonton Region Project. The AUC disallowed 15 per cent (approximately $3 million) of TransAlta's portion. TransAlta disputed this finding and filed a permission to appeal application with the Court of Appeal and a review and variance application with the AUC (the "R&V"). The AUC dismissed the R&V application on April 22, 2021. The permission to appeal was subsequently discontinued on July 5, 2021, which concludes this matter.

IX. Sarnia Outages

The Sarnia cogeneration facility experienced three separate outages between May 19, 2021, and June 9, 2021, that resulted in steam interruptions to its industrial customers. As a result, the customers have submitted claims for liquidated damages. Steam supply disruptions of this nature are atypical and infrequent at the Sarnia cogeneration facility. The Company conducted an investigation to determine the root cause of each of the three events, which concluded all three outages were within TransAlta's control. As such, liquidated damages in an amount dictated by the applicable agreements are payable by TransAlta to the customers for the three outages.

X. Kaybob 3 Cogeneration Dispute

The Company is engaged in a dispute with ET Canada as a result of ET Canada's purported termination of agreements between the parties to develop, construct and operate a 40 MW cogeneration facility at the Kaybob South No. 3 sour gas processing facility. TransAlta commenced an arbitration seeking full compensation for ET Canada's wrongful termination of the agreements. ET Canada seeks a declaration that the agreements were lawfully terminated. A hearing is scheduled for two weeks starting Jan. 9, 2023.

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 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 and 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, write-down of coal inventory and parts and material inventory related to the Highvale mine and coal operations at our natural gas converted facilities, going off-coal which resulted in the remaining coal supply payments on the existing coal supply agreement being recognized as an onerous contract, 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. Prior periods have been adjusted for comparable purposes.

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 (Loss) and Segment Assets

I. Reconciliation of Adjusted EBITDA to Earnings before Income Tax

Year ended Dec. 31, 2021	Hydro	Wind & Solar[1]	Gas[2]	Energy Transition[3]	Energy Marketing	Corporate	Total	Equity 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	–
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	1,132	728	173	4	2,768	(18)	(29)	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 write-down	–	–	–	(17)	–	–	(17)	–	17	–
Adjusted fuel and purchased power	16	17	374	432	–	4	843	–	211	1,054
Carbon compliance[4]	–	–	118	60	–	–	178	–	–	178
Gross margin	367	331	640	236	173	–	1,747	(18)	(240)	1,489
OM&A	42	59	175	117	36	84	513	(2)	–	511
Reclassifications and adjustments:										
Parts and materials write-down	–	–	(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 expense (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	322	262	494	133	137	(85)	1,263			
Equity income from associate										9
Finance lease income										25
Depreciation and amortization										(529)
Asset impairment										(648)
Net interest expense[6]										(245)
Foreign exchange gain										16
Gain on sale of assets and other										54
Loss before income taxes										(380)

(1) Skookumchuck has been included on a proportionate basis in the Wind and Solar segment.
(2) Includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal.
(3) Includes the segment previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal.
(4) As of the first quarter of 2021, carbon compliance costs have been reclassified from fuel and purchase power costs and disclosed separately. Prior periods have been adjusted for comparative purposes.
(5) Adjusted EBITDA is not defined and has no standardized meaning under IFRS.
(6) Includes accretion by segment and interest expense is not allocated as its related to Corporate debt and borrowings.

Year ended Dec. 31, 2020	Hydro	Wind & Solar[1]	Gas[2]	Energy Transition[3]	Energy Marketing	Corporate	Total	Equity accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	152	332	787	704	122	7	2,104	(3)	—	2,101
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	2	33	(14)	21	—	42	—	(42)	—
Decrease in finance lease receivable	—	—	17	—	—	—	17	—	(17)	—
Finance lease income	—	—	7	—	—	—	7	—	(7)	—
Unrealized foreign exchange loss on commodity	—	—	4	—	—	—	4	—	(4)	—
Adjusted revenues	152	334	848	690	143	7	2,174	(3)	(70)	2,101
Fuel and purchased power	8	25	325	435	—	12	805	—	—	805
Reclassifications and adjustments:										
Australian interest income	—	—	(4)	—	—	—	(4)	—	4	—
Mine depreciation	—	—	(100)	(46)	—	—	(146)	—	146	—
Coal inventory write-down	—	—	—	(37)	—	—	(37)	—	37	—
Adjusted fuel and purchased power	8	25	221	352	—	12	618	—	187	805
Carbon compliance[4]	—	—	120	48	—	(5)	163	—	—	163
Gross margin	144	309	507	290	143	—	1,393	(3)	(257)	1,133
OM&A	37	53	166	106	30	80	472	—	—	472
Taxes, other than income taxes	2	8	13	9	—	1	33	—	—	33
Net other operating expense (income)	—	—	(11)	—	—	—	(11)	—	—	(11)
Reclassifications and adjustments:										
Impact of Sheerness going off-coal	—	—	(28)	—	—	—	(28)	—	28	—
Adjusted net other operating income			(39)	—	—	—	(39)	—	28	(11)
Adjusted EBITDA[5]	105	248	367	175	113	(81)	927			
Equity income from associate										1
Finance lease income										7
Depreciation and amortization										(654)
Asset impairment										(84)
Net interest expense[6]										(238)
Foreign exchange loss										17
Gain on sale of assets and other										9
Loss before income taxes										(303)

(1) Skookumchuck has been included on a proportionate basis in the Wind and Solar segment.
(2) Includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal.
(3) Includes the segment previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal.
(4) As of the first quarter of 2021, carbon compliance costs have been reclassified from fuel and purchase power costs and disclosed separately. Prior periods have been adjusted for comparative purposes.
(5) Adjusted EBITDA is not defined and has no standardized meaning under IFRS.
(6) Includes accretion by segment and interest expense is not allocated as its related to Corporate debt and borrowings.

Year ended Dec. 31, 2019	Hydro	Wind & Solar	Gas(1)	Energy Transition(2)	Energy Marketing	Corporate	Total	Reclass adjustments	IFRS financials
Revenues	156	312	851	905	129	(6)	2,347	—	2,347
Reclassifications and adjustments:									
Unrealized mark-to-market (gain) loss	—	(17)	6	(12)	(10)	—	(33)	33	—
Decrease in finance lease receivable	—	—	24	—	—	—	24	(24)	—
Finance lease income	—	—	6	—	—	—	6	(6)	—
Adjusted revenues	156	295	887	893	119	(6)	2,344	3	2,347
Fuel and purchased power	7	16	315	539	—	4	881	—	881
Reclassifications and adjustments:									
Australian interest income	—	—	(4)	—	—	—	(4)	4	—
Mine depreciation	—	—	(81)	(40)	—	—	(121)	121	—
Adjusted fuel and purchased power	7	16	230	499	—	4	756	125	881
Carbon compliance	—	—	138	77	—	(10)	205	—	205
Gross margin	149	279	519	317	119	—	1,383	(122)	1,261
OM&A	36	50	162	124	30	73	475	—	475
Taxes, other than income taxes	3	8	9	8	—	1	29	—	29
Net other operating expense (income)	—	(10)	(41)	—	—	2	(49)	—	(49)
Termination of Sundance B and C PPAs	—	—	(14)	(42)	—	—	(56)	—	(56)
Adjusted EBITDA(3)	110	231	403	227	89	(76)	984		
Finance lease income									6
Depreciation and amortization									(590)
Asset impairment									(25)
Gain on termination of Keephills 3 coal rights contract									88
Net interest expense(4)									(179)
Foreign exchange loss									(15)
Gain on sale of assets and other									46
Earnings before income taxes									193

(1) Includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal.
(2) Includes the segment previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal.
(3) Adjusted EBITDA is not defined and has no standardized meaning under IFRS.
(4) Includes accretion by segment and interest expense is not allocated as its related to Corporate debt and borrowings.

II. Selected Consolidated Statements of Financial Position Information

As at Dec. 31, 2021	**Hydro**	**Wind and Solar**	**Gas[(1)]**	**Energy Transition[(2)]**	**Energy Marketing**	**Corporate**	**Total**
PP&E	**466**	**2,304**	**2,036**	**481**	**—**	**33**	**5,320**
Right-of-use assets	**5**	**64**	**7**	**1**	**—**	**18**	**95**
Intangible assets	**3**	**147**	**56**	**9**	**5**	**36**	**256**
Goodwill	**258**	**175**	—	—	**30**	**—**	**463**

As at Dec. 31, 2020	Hydro	Wind and Solar	Gas[(1)]	Energy Transition[(2)]	Energy Marketing	Corporate	Total
PP&E	467	2,005	2,102	1,232	—	16	5,822
Right-of-use assets	6	55	5	53	—	22	141
Intangible assets	4	159	66	36	7	41	313
Goodwill	258	175	—	—	30	—	463

(1) Includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal.
(2) Includes the segment previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal.

III. Selected Consolidated Statements of Cash Flows Information

Additions to non-current assets are as follows:

Year ended Dec. 31, 2021	**Hydro**	**Wind and Solar**	**Gas[(1)]**	**Energy Transition[(2)]**	**Energy Marketing**	**Corporate**	**Total**
Additions to non-current assets:							
PP&E	**29**	**166**	**167**	**90**	**—**	**28**	**480**
Intangible assets	**—**	**—**	**—**	**1**	**—**	**8**	**9**

Year ended Dec. 31, 2020	Hydro	Wind and Solar	Gas[(1)]	Energy Transition[(2)]	Energy Marketing	Corporate	Total
Additions to non-current assets:							
PP&E	22	174	199	78	—	13	486
Intangible assets	—	—	—	1	—	13	14

Year ended Dec. 31, 2019	Hydro	Wind and Solar	Gas[(1)]	Energy Transition[(2)]	Energy Marketing	Corporate	Total
Additions to non-current assets:							
PP&E	23	229	74	90	—	1	417
Intangible assets	—	—	—	2	—	12	14

(1) Includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal.
(2) Includes the segment previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal.

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	2021	2020	2019
Depreciation and amortization expense on the Consolidated Statements of Earnings (Loss)	**529**	654	590
Depreciation included in fuel, carbon compliance and purchased power (Note 6)	**190**	144	119
Depreciation and amortization on the Consolidated Statements of Cash Flows	**719**	798	709

C. Geographic Information

I. Revenues

Year ended Dec. 31	2021	2020	2019
Canada	**1,854**	1,227	1,460
US	**731**	716	727
Australia	**136**	158	160
Total revenue	**2,721**	2,101	2,347

II. Non-Current Assets

	Property, plant and equipment		Right-of-use assets		Intangible assets		Other assets	
As at Dec. 31	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020
Canada	**4,051**	4,661	**52**	107	**141**	185	**15**	74
US	**860**	737	**39**	30	**85**	94	**61**	61
Australia	**409**	424	**4**	4	**30**	34	**66**	71
Total	**5,320**	5,822	**95**	141	**256**	313	**142**	206

D. Significant Customer

During the year ended Dec. 31, 2021, sales to the AESO represent 35 per cent of the Company's total revenue (2020 – sales to the AESO represented 15 per cent of the Company's total revenue). There were no other companies greater 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	2021	2020	2019
Financial Summary			
STATEMENT OF EARNINGS			
Revenues	**2,721**	2,101	2,347
Operating income (loss)	**(239)**	(99)	335
Earnings (loss) before income taxes	**(380)**	(303)	193
Net earnings (loss) attributable to common shareholders	**(576)**	(336)	52
STATEMENT OF FINANCIAL POSITION			
Total assets	**9,226**	9,747	9,508
Current portion of long-term debt, net of cash and cash equivalents	**(103)**	(598)	102
Credit facilities, long-term debt and finance lease obligations	**2,423**	3,256	2,699
Exchangeable securities	**735**	730	326
Non-controlling interests	**1,011**	1,084	1,101
Preferred shares	**942**	942	942
Equity attributable to common shareholders(1)	**640**	1,410	2,019
Principal portion of restricted cash on TransAlta OCP and fair value (asset) liability of hedging instruments on debt(1)	**(19)**	(13)	(17)
Total capital(2)	**5,629**	6,811	7,172
CASH FLOWS			
Cash flow from operating activities	**1001**	702	849
Cash flow from (used in) investing activities	**(472)**	(687)	(512)
COMMON SHARE INFORMATION (per share)			
Net earnings (loss)	**(2.13)**	(1.22)	0.18
Comparable earnings(1)	**n/a**	n/a	n/a
Dividends declared on common share	**0.19**	0.22	0.12
Book value per common share (at year-end)(1)	**2.37**	5.13	7.14
Market price:			
High	**14.61**	11.23	10.14
Low	**9.57**	5.32	5.50
Close (Toronto Stock Exchange at Dec. 31)	**14.05**	9.67	9.28
RATIOS (percentage except where noted)			
Adjusted net debt to adjusted EBITDA(1,3,4) (times)	**2.6**	3.9	3.9
Return on equity attributable to common shareholders(1)	**(116.6)**	(30.3)	3.3
Comparable return on equity attributable to common shareholders(1)	**n/a**	n/a	n/a
Return on capital employed(1)	**(4.5)**	(1.5)	4.1
Comparable return on capital employed(1)	**n/a**	n/a	n/a
Earnings coverage (times)(1)	**(1.0)**	(0.5)	1.5
Dividend payout ratio based on FFO(1,4)	**5.1**	7.0	6.6
Adjusted EBITDA(1,3,4) (in millions of Canadian dollars)	**1,263**	927	984
Dividend coverage(1,4) (times)	**23.0**	15.6	18.6
Dividend yield(1)	**1.3**	1.7	1.7
FFO before interest to adjusted interest coverage(1,4) (times)	**5.3**	4.2	4.5
Weighted average common shares for the year (in millions)	**271**	275	283
Common shares outstanding at Dec. 31 (in millions)	**271**	270	277
STATISTICAL SUMMARY			
Number of employees	**1,282**	1,476	1,543
Gross installed capacity (MW)(5)			
Energy Transition (7)	**1,472**	2,548	2,915
Gas(6,8)	**3,084**	3,082	3,049
Renewables (wind, solar and hydro)	**2,694**	2,498	2,421
Equity investments	**137**	137	—
Total generating capacity	**7,387**	8,265	8,385
Total generation production (GWh)	**22,105**	24,980	29,071

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.

(2) Total capital for 2011 to 2014 has been revised to align with the 2015 calculation methodology.

2018	2017	2016	2015	2014	2013	2012	2011
2,249	2,307	2,397	2,267	2,623	2,292	2,210	2,618
160	138	478	148	442	195	(214)	645
(96)	(54)	314	221	239	(12)	(445)	449
(248)	(190)	117	(24)	141	(71)	(615)	290
9,428	10,304	10,996	10,947	9,833	9,624	9,503	9,780
59	433	334	33	708	175	582	284
3,119	2,960	3,722	4,408	3,305	4,130	3,610	3,721
—	—	—	—	—	—	—	—
1,137	1,059	1,152	1,029	594	517	330	358
942	942	942	942	942	781	—	—
2,055	2,384	2,569	2,419	2,342	2,125	3,018	3,274
(10)	(30)	(163)	(190)	(96)	(16)	50	32
7,275	7,748	8,556	8,641	7,795	7,712	7,590	7,669
820	626	744	432	796	765	520	690
(394)	87	(327)	(573)	(292)	(703)	(1,048)	(608)
(0.86)	(0.66)	0.41	(0.09)	0.52	(0.27)	(2.62)	1.31
n/a	n/a	0.13	(0.17)	0.25	0.31	0.50	1.05
0.20	0.16	0.30	0.72	0.83	1.16	1.16	1.16
7.16	8.28	8.92	8.52	8.52	7.92	8.78	12.08
7.90	8.50	7.54	12.34	14.94	16.86	21.37	23.24
5.44	6.88	3.76	4.13	9.81	12.91	14.11	19.45
5.59	7.45	7.43	4.91	10.52	13.48	15.12	21.02
3.6	3.6	3.8	5.4	4.2	4.6	4.6	3.8
(15.8)	(10.0)	5.4	(1.2)	6.3	(3.2)	(25.9)	10.6
n/a	n/a	1.7	(2.3)	3.0	3.7	4.9	8.4
0.7	2.1	5.3	4.6	5.8	2.8	(3.1)	8.3
n/a	n/a	4.4	3.0	5.1	5.2	5.3	7.0
0.2	0.6	1.7	1.5	1.7	0.8	(1.0)	2.7
6.1	4.3	8.1	30.0	26.4	43.1	25.1	24.0
1,123	1,062	1,144	867	1,036	1,023	1,015	1,044
18.3	14.1	11.1	3.3	5.7	6.3	4.7	3.5
2.9	2.1	4.0	14.7	7.9	8.6	7.7	5.5
20.8	20.4	16.3	14.3	16.9	15.2	16.7	20.1
4.8	4.3	3.9	3.7	3.8	3.7	3.3	4.4
287	288	288	280	273	264	235	222
285	288	288	284	275	268	255	224
1,883	2,228	2,341	2,380	2,786	2,772	2,084	2,235
3,147	3,707	3,707	3,708	3,693	3,693	3,140	2,904
2,819	2,827	2,906	2,823	2,949	3,197	3,142	2,988
2,308	2,289	2,334	2,350	2,204	2,202	2,058	1,974
—	—	—	—	—	396	390	390
8,273	8,823	8,947	8,881	8,846	9,488	8,730	8,256
28,409	36,900	38,157	40,673	45,002	42,482	38,750	41,012

(3) 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 = net earnings attributable to shareholders + income taxes + net interest expense / 50 per cent dividends paid on preferred shares + interest on debt - interest income

Dividend payout ratio = common share dividends declared / 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

FFO before interest to adjusted interest coverage = FFO - PPA termination payments + interest on debt, exchangeable securities and lease liabilities - interest income - capitalized interest / interest on debt, exchangeable securities (excluding interest on exchangeable preferred shares) and lease liabilities - interest income + 50 per cent dividends paid on preferred shares and exchangeable preferred shares

Plant Summary

As at Dec. 31, 2021	Facility	Nameplate capacity (MW)[1]	Consolidated Interest	Gross Installed capacity[1]	Ownership (%)	Net Capacity Ownership Interest (MW)[1][2]	Region	Revenue source	Contract expiry date
Hydro	Brazeau, AB	355	100 %	355	100 %	355	Western Canada	Merchant	–
26 facilities	Bighorn, AB	120	100 %	120	100 %	120	Western Canada	Merchant	–
	Spray, AB	112	100 %	112	100 %	112	Western Canada	Merchant	–
	Ghost, AB	54	100 %	54	100 %	54	Western Canada	Merchant	–
	Rundle, AB	50	100 %	50	100 %	50	Western Canada	Merchant	–
	Cascade, AB	36	100 %	36	100 %	36	Western Canada	Merchant	–
	Kananaskis, AB	19	100 %	19	100 %	19	Western Canada	Merchant	–
	Bearspaw, AB	17	100 %	17	100 %	17	Western Canada	Merchant	–
	Pocaterra, AB	15	100 %	15	100 %	15	Western Canada	Merchant	–
	Horseshoe, AB	14	100 %	14	100 %	14	Western Canada	Merchant	–
	Barrier, AB	13	100 %	13	100 %	13	Western Canada	Merchant	–
	Taylor, AB*	13	100 %	13	100 %	13	Western Canada	Merchant	–
	Interlakes, AB	5	100 %	5	100 %	5	Western Canada	Merchant	–
	Belly River, AB*	3	100 %	3	100 %	3	Western Canada	Merchant	–
	Three Sisters, AB	3	100 %	3	100 %	3	Western Canada	Merchant	–
	Waterton, AB*	3	100 %	3	100 %	3	Western Canada	Merchant	–
	St. Mary, AB*	2	100 %	2	100 %	2	Western Canada	Merchant	–
	Upper Mamquam, BC*	25	100 %	25	100 %	25	Western Canada	LTC[12]	2025
	Pingston, BC*	45	50 %	23	100 %	23	Western Canada	LTC	2023
	Bone Creek, BC*	19	100 %	19	100 %	19	Western Canada	LTC	2031
	Akolkolex, BC*	10	100 %	10	100 %	10	Western Canada	LTC	2046
	Ragged Chute, ON*	7	100 %	7	100 %	7	Eastern Canada	LTC	2029
	Misema, ON*	3	100 %	3	100 %	3	Eastern Canada	LTC	2027
	Galetta, ON*	2	100 %	2	100 %	2	Eastern Canada	LTC	2030
	Appleton, ON*	1	100 %	1	100 %	1	Eastern Canada	LTC	2030
	Moose Rapids, ON*	1	100 %	1	100 %	1	Eastern Canada	LTC	2030
Total Hydro		**947**		**925**		**925**			
Wind &	Summerview 1, AB*	68	100 %	68	100 %	68	Western Canada	Merchant	–
Battery Storage	Summerview 2, AB*	66	100 %	66	100 %	66	Western Canada	Merchant	–
27 facilities	Ardenville, AB*	69	100 %	69	100 %	69	Western Canada	Merchant	–
	Blue Trail and Macleod Flats, AB*	69	100 %	69	100 %	69	Western Canada	Merchant	–
	Castle River, AB*[3]	44	100 %	44	100 %	44	Western Canada	Merchant	–
	McBride Lake, AB*	75	50 %	38	100 %	38	Western Canada	LTC	2024
	Soderglen, AB*	71	50 %	36	100 %	36	Western Canada	Merchant	–
	Cowley North, AB*	20	100 %	20	100 %	20	Western Canada	Merchant	–
	Oldman, AB*	4	100 %	4	100 %	4	Western Canada	Merchant	–
	Sinnott, AB*	7	100 %	7	100 %	7	Western Canada	Merchant	–
	Windrise, AB*	206	100 %	206	100 %	206	Western Canada	LTC	2041
	WindCharger battery storage, AB*	10	100 %	10	100 %	10	Western Canada	Merchant	–
	Melancthon, ON*[4]	200	100 %	200	100 %	200	Eastern Canada	LTC	2026-2028
	Wolfe Island, ON*	198	100 %	198	100 %	198	Eastern Canada	LTC	2029
	Kent Breeze, ON*	20	100 %	20	100 %	20	Eastern Canada	LTC	2031
	Kent Hills, NB*[5]	167	100 %	167	83 %	139	Eastern Canada	LTC	2035
	Le Nordais, QC*	98	100 %	98	100 %	98	Eastern Canada	LTC	2033
	New Richmond, QC*	68	100 %	68	100 %	68	Eastern Canada	LTC	2033
	Wyoming Wind, WY*	140	100 %	140	100 %	140	United States	LTC	2028
	Lakeswind, MN*	50	100 %	50	100 %	50	United States	LTC	2034
	Big Level, PA*	90	100 %	90	100 %	90	United States	LTC	2034
	Antrim, NH*	29	100 %	29	100 %	29	United States	LTC	2039
	Skookumchuck, WA[6]	137	49 %	67	100 %	67	United States	LTC	2040
Total Wind		**1,906**		**1,763**		**1,735**			
Solar	Mass Solar, MA*[7]	21	100 %	21	100 %	21	United States	LTC	2032-2035
2 facilities	North Carolina Solar, NC[8]	122	100 %	122	100 %	122	United States	LTC	2033
Total Solar		**143**		**143**		**143**			

As at Dec. 31, 2021	Facility	Nameplate capacity (MW)[1]	Consolidated Interest	Gross Installed capacity[1]	Ownership (%)	Net Capacity Ownership Interest (MW)[1][2]	Region	Revenue source	Contract expiry date
Gas	Keephills 2, AB	395	100 %	395	100 %	395	Western Canada	Merchant	–
17 facilities	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	–
	Fort Saskatchewan, AB	118	60 %	71	50 %	35	Western Canada	LTC/Merchant	2029
	Sarnia, ON*	499	100 %	499	100 %	499	Eastern Canada	LTC	2022-2032
	Ottawa, ON	74	100 %	74	50 %	37	Eastern Canada	LTC/ Merchant	2020-2033
	Windsor, ON	72	100 %	72	50 %	36	Eastern Canada	LTC/ Merchant	2031
	Ada, MI* (6)	29	100 %	29	100 %	29	United States	LTC	2026
	Parkeston, WA*[11]	110	50 %	55	100 %	55	Australia	LTC	2026
	Southern Cross, WA*[10][11]	245	100 %	245	100 %	245	Australia	LTC	2038
	South Hedland, WA*[11]	150	100 %	150	100 %	150	Australia	LTC	2042
Total Gas		**3,586**		**3,084**		**2,775**			
Energy Transition	Sundance 4, AB[13]	406	100 %	406	100 %	406	Western Canada	Merchant	–
4 facilities	Keephills 1, AB[14]	395	100 %	395	100 %	395	Western Canada	Merchant	–
	Centralia, WA	670	100 %	670	100 %	670	United States	LTC/ Merchant	2025 [15]
	Skookumchuck, WA	1	100 %	1	100 %	1	United States	LTC	2025
Total Energy Transition		**1,472**		**1,472**		**1,472**			
Total		**8,054**		**7,387**		**7,050**			

** TransAlta Renewables Inc. facility.*
(1) Megawatts 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) Includes 100% of TransAlta Renewables assets. As of Dec. 31, 2021, TransAlta owns approximately 60% of the outstanding shares of TransAlta Renewables.
(3) Includes seven individual turbines at other locations.
(4) Comprised of two facilities.
(5) Comprised of three facilities.
(6) Effective Jan. 1, 2021, facility has been sold to TransAlta Renewables.
(7) Comprised of four ground-mounted projects and four roof-top projects.
(8) Comprised of 20 facilities.
(9) The Poplar Creek plant is operated by Suncor and ownership of the facility will transfer to Suncor in 2030.
(10) Comprised of four facilities.
(11) Gas/diesel.
(12) LTC refers to Long-Term Contract.
(13) Effective Jan. 1, 2022, the maximum capability of this unit has been reduced to 113 MW.
(14) Keephills Unit 1 was retired from service effective Dec. 31, 2021.
(15) 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 & Safety ("EHS") Management Systems	2021	2020	2019
EHS management system audits[1]	**15**	19	12
Health and Safety compliance audits[2]	**4**	8	6
Total EHS audits	**11**	11	6

Environmental Performance [3]	2021	2020	2019
Resource or energy use[4]			
Coal combustion (tonnes)	**4,094,000**	6,637,000	9,092,000
Natural gas combustion (GJ)	**106,774,000**	82,917,000	76,931,000
Diesel combustion (L)	**7,595,000**	6,955,000	10,179,000
Gasoline consumption: vehicle (L)	**864,000**	933,000	1,099,000
Diesel consumption: vehicle (L)	**6,705,000**	10,971,000	21,531,000
Propane consumption: vehicle (L)	**6,000**	6,000	96,000
Electricity: building operations (MWh)	**175,000**	186,000	241,000
Natural gas: building operations (GJ)	**100,000**	135,000	138,000
Propane: building operations (L)	**184,000**	198,000	177,000
Kerosene: building operations (L)	**65,000**	48,000	84,000
Total resource or energy use (GJ)	**191,272,000**	278,977,000	345,673,000
Greenhouse gas emissions[5]			
Carbon dioxide (tonnes CO_2e) √	**12,421,000**	16,246,000	20,471,000
Methane (tonnes CO_2e) √	**25,000**	34,000	51,000
Nitrous oxide (tonnes CO_2e) √	**59,000**	80,000	111,000
Sulphur hexafluoride (tonnes CO_2e)	**370**	110	90
Total greenhouse gas emissions (tonnes CO_2e) [6] **√**	**12,506,000**	**16,361,000**	**20,633,000**
Greenhouse gas emission intensity (tonnes CO_2e/MWh) [7] √	**0.60**	**0.67**	**0.75**
Scope 1 emissions (% of total GHG emissions)	**99**	99	99
Scope 2 emissions (% of total GHG emissions)	**1**	1	1
Scope 1 emissions reported to national regulatory bodies (%)	**100**	100	100
Air emissions[8]			
Total sulphur dioxide emissions (tonnes) √	**7,000**	12,000	16,000
Sulphur dioxide emission intensity (kg/MWh) √	**0.34**	0.49	0.58
Total nitrogen oxide emissions (tonnes) √	**15,000**	21,000	26,000
Nitrogen oxide emission intensity) (kg/MWh) √	**0.73**	0.88	0.96
Total particulate matter emissions (tonnes) √	**790**	4,000	8,000
Particulate matter emission intensity (kg/MWh) √	**0.04**	0.16	0.28
Total mercury emissions (kilograms) √	**40**	60	60
Mercury emission intensity (mg/MWh) √	**1.93**	2.33	2.37

Environmental Performance *(continued)*	**2021**	**2020**	**2019**
Water management[9]			
Water withdrawal – water utility/municipality/customer (million m^3)	**240**	230	260
Water withdrawal – surface water (million m^3)	**0**	0	0
Water withdrawn – all sources (million m^3) √	**240**	230	260
Water discharge – all sources (million m^3) √	**210**	200	220
Water consumption (million m^3) √	**30**	40	40
Water consumption intensity (m^3/MWh)[10] √	**1.52**	1.47	1.55
Waste management[11]			
Non-hazardous[12]			
Landfill (tonnes) √	**1,000**	11,000	880
Landfill (L) √	**47,000**	55,000	35,000
Ash disposal: mine (tonnes) [13] √	**232,000**	408,000	641,000
Ash disposal: lagoon (tonnes) [14] √	**44,000**	98,000	117,000
Recycled (tonnes) √	**4,000**	8,000	2,000
Recycled (L) [15] √	**1,788,000**	1,855,000	3,605,000
Reuse (tonnes) √	**176,000**	533,000	746,000
Storage (tonnes) √	**31,000**	53,000	0
Compostable (tonnes)	**10**	10	0
Hazardous[16]			
Landfill (tonnes) √	**200**	20	60
Landfill (L) √	**24,000**	59,000	53,000
Recycled (tonnes) √	**0**	20	80
Recycled (L) √	**22,837,000**	20,090,000	18,947,000
Land use and reclamation[17]			
Land used in mining activities – disturbed (cumulative hectares) √	**12,600**	12,600	12,600
Land used in mining activities – reclaimed (cumulative hectares) √	**4,800**	4,800	4,800
Reclamation of land used in mining activities (% of land disturbed) √	**38**	38	38
Land used in mining activities: disturbed minus reclaimed (hectares) √	**7,700**	7,700	7,700
Land used by facilities, offices and equipment (hectares) √	**5,000**	4,900	4,900
Total land use (cumulative hectares) √	**12,700**	12,600	12,700
Environmental incidents[18]			
Significant environmental incidents	**0**	6	3
Regulatory non-compliance environmental incidents	**2**	2	6
Total significant environmental incidents √	**2**	8	9
Environmental enforcement actions[19]	**1**	0	1
Environmental fines ($ thousands)	**3**	0	4
Environmental Spills[20]			
Volume of significant environmental spills (m^3)	**6**	4	528

Social Performance	**2021**	2020	2019
Workplace practices			
Employees	**1,282**	1,476	1,543
Number of full-time employees	**1,181**	1,392	1,471
Number of part-time employees	**15**	16	18
Number of contingent employees	**86**	68	54
Employees represented by independent trade union organizations[(21)] (%)	**33**	41	45
Voluntary employee turnover rate[(22)] (%)	**8**	9	14
Diversity			
Women in workforce (% of all employees)	**24**	21	20
Women in senior management (%)	**38**	43	50
Women on Board of Directors (%)	**42**	45	33
Health and safety			
Health and safety enforcement actions[(23)]	**0**	0	3
Health and safety fines ($ thousands)	**0**	0	0
Employee & contractor fatalities √	**0**	0	0
Lost-time injury (LTI) incidents (absence from work)[(24)] √	**3**	5	5
Medical aid (MA) incidents (no absence from work)[(25)] √	**9**	9	7
Restricted work injury (RWI) incidents (no absence from work)[(26)] √	**5**	2	3
Total recordable injuries to employees & contractors √	**17**	16	15
Exposure hours [(27)]	**4,134,000**	3,948,000	4,108,000
Total Recordable Injury Frequency (TRIF) (employees and contractors)[(28)]√	**0.82**	0.81	0.73
Community relations			
Community investments ($ millions)[(29)]	**3.0**	2.2	2.1

√ 2021 data has been third-party 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.

Environment Health & Safety Management Systems	Alignment with GRI or SASB standards
EHS management system audits	
Health and Safety compliance audits	
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 greenhouse gas emissions (tonnes CO_2e)	SASB IF-EU-110a.1
Greenhouse gas emission intensity (tonnes CO_2e/MWh)	GRI 305-4
Scope 1 emissions (% of total GHG emissions)	SASB IF-EU-110a.1
Scope 2 emissions (% of total GHG emissions)	GRI 305-2
Scope 1 emissions reported to national regulatory bodies (%)	SASB IF-EU-110a.1
Air emissions	
Total sulphur dioxide emissions (tonnes)	SASB IF-EU-120a.1
Sulphur dioxide emission intensity (kg/MWh)	
Total nitrogen oxide emissions (tonnes)	SASB IF-EU-120a.1
Nitrogen oxide emission intensity (kg/MWh)	
Total particulate matter emissions (tonnes)	SASB IF-EU-120a.1
Particulate matter emission intensity (kg/MWh)	
Total mercury emissions (kilograms)	SASB IF-EU-120a.1
Mercury emission intensity (mg/MWh)	

Environmental Performance *(continued)*	Alignment with GRI or SASB Standards
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)	SASB IF-EU-140a.1
Water consumption (million m^3)	SASB IF-EU-140a.1
Water intensity (m^3/MWh)	
Waste management	
Non-hazardous	
Landfill (tonnes)	GRI 306-2
Landfill (L)	GRI 306-2
Ash disposal: mine (tonnes)	GRI 306-2
Ash disposal: lagoon (tonnes)	GRI 306-2
Recycled (tonnes)	GRI 306-2
Recycled (L)	GRI 306-2
Reuse (tonnes)	GRI 306-2
Storage (tonnes)	GRI 306-2
Compostable (tonnes)	GRI 306-2
Hazardous	
Landfill (tonnes)	GRI 306-2
Landfill (L)	GRI 306-2
Recycled (tonnes)	GRI 306-2
Recycled (L)	GRI 306-2
Land use and reclamation	
Land used in mining activities – disturbed (cumulative hectares)	
Land used in mining activities – reclaimed (cumulative hectares)	
Reclamation of land used in mining activities (% of land disturbed)	
Land used in mining activities: disturbed minus reclaimed (hectares)	
Land used by plants, offices and equipment (hectares)	
Total land use (cumulative hectares)	
Environmental incidents	
Significant environmental incidents	
Regulatory non-compliance environmental incidents	GRI 307-1
Total significant environmental incidents	
Environmental enforcement actions	GRI 307-1
Environmental fines ($ thousands)	GRI 307-1
Environmental spills	
Volume of significant spills (m^3)	GRI 306-3

Social Performance	Alignment with GRI or SASB Standards
Workplace practices	
Employees	GRI 102-7
Number of full-time employees	
Number of part-time employees	
Number of contingent employees	
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	
Health and safety fines ($ thousands)	
Employee & 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 & 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 are rounded to the nearest one thousand except where values are <1000, in which case they are rounded to the nearest 10; ii) 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.*
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. 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 4th Assessment Report, Canada's GHG Inventory 1990-2019, US EPA eGRID Summary Tables 2019 and Australia NGERS Measurement Determination. Applying harmonized global warming potentials and emission factors across our fleet would result in a minor variance to our overall calculated GHG totals. An estimate of our scope 3 emissions can be found in our 2021 MD&A and our 2021 CDP climate change report.*
6. *Gross GHG emissions or gross CO_2e emissions is the sum of 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. An adjustment was made to 2019 SF_6 emissions at our Sarnia facility from 2,000 tonnes CO_2e to 90 tonnes CO_2e as a result of an internal discrepancy. A comparatively small change in the amount of SF_6 itself changes the resulting amount in CO_2e significantly due to the high global warming potential of 22,800 tonnes CO_2e.*
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.*
8. *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 $PM_{2.5}$ and PM_{10}. Air emission intensities are calculated by dividing total operational emissions by 100 per cent of production (MWh) from operated facilities, irrespective of financial ownership. Historical adjustments to 2020 particulate matter emissions and intensity were made to reflect accrual adjustments for road dust at our Highvale facility.*
9. *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. 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. Water withdrawal, discharge and consumption values for 2020 were adjusted to reflect a new rounding approach.*
10. *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. Minor historical adjustment to 2020 water consumption data (see Note 9) resulted in adjustments to 2020 water intensity data.*
11. *Adjustments were made to historical 2020 waste values to reflect accrued volumes from 2020 after we received final waste manifests as part of the reclamation project at our Mississauga facility. As a result, approximately 23,000 tonnes eq. were added from Mississauga to multiple waste categories in 2020.*
12. *Non-hazardous waste 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.*
13. *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.*
14. *Ash disposal: lagoon is fly ash and bottom ash from Keephills coal production, which is treated and then sent to ash lagoons for disposal.*
15. *In 2021, we adjusted our reported 2020 non-hazardous waste recycled (L) volumes to reflect accrued volumes from our Sarnia facility.*

16. *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.*
17. *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. Land use calculations were modified in 2021 to include a greater portion of the land used by Transalta including all surrounding land and land leased to our customers. As a result, minor adjustments were made to historical 2020 and 2019 data for land used by facilities, offices and equipment.*
18. *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 resulted in an impact to the environment with low level damage to the ecosystem that is reversible within one to three years or mortalities of less than 0.2% of a given species when compared to the overall population. Our internal definition of significant environmental incidents in 2020 and 2019 included all incidents involving mortality of a single listed species as reflected in our 2020 and 2019 reported values. We have updated our internal definition to reflect what we deem to be a more appropriate way to measure a significant environmental event related to species mortalities; the internal definition now takes into consideration mortality impacts to the species in relation to overall species population. 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.*
19. *Environmental enforcement actions are a violation or non-compliance to regulations or exceedance of limits in company operating approvals that result in enforcement action including stop work orders, fines or suspension of operating approvals.*
20. *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.*
21. *TransAlta has approximately 420 unionized workers working primarily in our operational business units.*
22. *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.*
23. *Health and safety enforcement actions are a violation or non-compliance to regulations or exceedance of limits in company operating approvals that result in enforcement action including stop work orders, fines or suspension of operating approvals.*
24. *Lost-time injuries (LTIs) are injuries that resulted in the worker being away from work beyond the day of the injury.*
25. *Medical aids (MAs) are injuries that resulted in medical treatment beyond first aid.*
26. *Restricted work injuries (RWIs) are injuries that resulted in the worker being unable to perform all normally scheduled and assigned work activities.*
27. *Exposure hours are total hours worked by all TransAlta employees and contractors, and include full-time, part-time, direct, contract, executive, labor, salary, hourly, and seasonal employees in all locations, but exclude prime contractors. Exposure hours have been rounded to the nearest thousand.*
28. *Total Recordable Injury Frequency (TRIF) measures restricted work, medical aid and lost-time injuries per 200,000 hours worked. In 2021, we did not track Total Injury Frequency (TIF) rate, which tracks all injuries including minor first aids. Therefore, in the 2021 MD&A we included information on total recordable injuries to employees and contractors and excluded historical information on TIF, first aids and total injuries to employees and contractors.*
29. *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 the Board of Directors and Management of TransAlta Corporation ("TransAlta")

Scope of EY Engagement

We have been engaged by TransAlta to perform a 'limited assurance engagement', as defined by International Standards on Assurance Engagements, hereafter referred to as the engagement, over the select performance indicators detailed in the accompanying Schedule (collectively, the "Subject Matter") as at December 31, 2021 reported in TransAlta's 2021 Annual Integrated Report (the "Report").

Other than as described in the preceding paragraph, which sets out the scope of the engagement, our assurance engagement does not extend to any other information included in, or linked to, from the Report and accordingly, we do not express a conclusion on this other 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, 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 evidence we have obtained.

We conducted our engagement in accordance with the International Standard for Assurance Engagements Other Than Audits or Reviews of Historical Financial Information ("ISAE 3000") and the International Standard for Assurance Engagements 3410, Assurance Engagements on Greenhouse Gas Statements ("ISAE 3410"). This standard requires 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 conclusions.

Our Independence and Quality Control

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 behavior.

The firm applies Canadian Standard on Quality Control 1, Quality Control for Firms that Perform Audits and Reviews of Financial Statements, and Other Assurance Engagements, and accordingly maintains a comprehensive system of quality control including documented policies and 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.

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.

A limited assurance engagement consists of making inquiries, 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 and internal controls;
- 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
- 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

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 as reported in the Report for year-end December 31st, 2021 are not prepared, in all material respects, in accordance with the Criteria.

Ernst + Young LLP

Ernst & Young LLP
February 23, 2022
Calgary, Canada

Schedule

Our limited assurance engagement was performed on the following Subject Matter for the year ended December 31, 2021:

Performance Indicator	Unit of Measure	Criteria	Value
Greenhouse Gas Emissions			
Carbon dioxide	tonnes CO_2e	SASB IF-EU-110a.1	12,421,000
Methane	tonnes CO_2e	SASB IF-EU-110a.1	25,000
Nitrous oxide	tonnes CO_2e	SASB IF-EU-110a.1	59,000
Total greenhouse gas emissions	tonnes CO_2e	SASB IF-EU-110a.1	12,506,000
Greenhouse gas emission intensity	tonnes CO_2e /MWh	GRI 305-4	0.60
Air Emissions			
Total sulphur dioxide emissions	Tonnes	SASB IF-EU-120a.1	7,000
Sulphur dioxide emission intensity	kg/MWh	Internally developed criteria as described in the footnotes to the Sustainability Performance Indicators	0.34
Total nitrogen oxide emissions	Tonnes	SASB IF-EU-120a.1	15,000
Nitrogen oxide emission intensity	kg/MWh	Internally developed criteria as described in the footnotes to the Sustainability Performance Indicators	0.73
Total particulate matter emissions	Tonnes	SASB IF-EU-120a.1	790
Particulate matter emission intensity	kg/MWh	Internally developed criteria as described in the footnotes to the Sustainability Performance Indicators	0.04
Total mercury emissions	kg	SASB IF-EU-120a.1	40
Mercury emission intensity	mg/MWh	Internally developed criteria as described in the footnotes to the Sustainability Performance Indicators	1.93
Water Management			
Water withdrawn – all sources	Million m^3	SASB IF-EU-140a.1	240
Water discharge – all sources	Million m^3	SASB IF-EU-140a.1	210
Water consumption	Million m^3	SASB IF-EU-140a.1	30
Water consumption intensity	m^3/MWh	SASB IF-EU-140a.1	1.52

Performance Indicator	Unit of Measure	Criteria	Value
Waste Management			
Non-hazardous			
Landfill	Tonnes	GRI 306-2	1,000
Landfill	Litres	GRI 306-2	47,000
Ash disposal: mine	Tonnes	GRI 306-2	232,000
Ash disposal: lagoon	Tonnes	GRI 306-2	44,000
Recycled	Tonnes	GRI 306-2	4,000
Recycled	Litres	GRI 306-2	1,788,000
Reuse	Tonnes	GRI 306-2	176,000
Storage	Tonnes	GRI 306-2	31,000
Hazardous			
Landfill	Tonnes	GRI 306-2	200
Landfill	Litres	GRI 306-2	24,000
Recycled	Tonnes	GRI 306-2	0
Recycled	Litres	GRI 306-2	22,837,000
Land Use and Reclamation			
Land used in mining activities – disturbed	Cumulative hectares	Internally developed criteria as described in the footnotes to the Sustainability Performance Indicators	12,600
Land used in mining activities – reclaimed	Cumulative hectares	Internally developed criteria as described in the footnotes to the Sustainability Performance Indicators	4,800
Land reclamation (used in mining activities)	% of land disturbed	Internally developed criteria as described in the footnotes to the Sustainability Performance Indicators	38
Land used in mining activities: disturbed minus reclaimed	Hectares	Internally developed criteria as described in the footnotes to the Sustainability Performance Indicators	7,700
Land used by facilities, offices and equipment	Hectares	Internally developed criteria as described in the footnotes to the Sustainability Performance Indicators	5,000
Total land use	Cumulative hectares	Internally developed criteria as described in the footnotes to the Sustainability Performance Indicators	12,700
Environmental Incidents			
Total significant environmental incidents	Number	GRI 307-1 and internally developed criteria as described in the footnotes to the Sustainability Performance Indicators	2
Health and Safety			
Employee & contractor fatalities	Number	SASB IF-EU-320a.1	0
Lost-time injury (LTI) incidents	Number	SASB IF-EU-320a.1	3
Medical aid (MA) incidents	Number	SASB IF-EU-320a.1	9
Restricted work injury (RWI) incidents	Number	SASB IF-EU-320a.1	5
Total recordable injuries to employees & contractors	Number	SASB IF-EU-320a.1	17
Total Recordable Injury Frequency (TRIF) (employees and contractors)	Rate	SASB IF-EU-320a.1	0.82

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
Feb. 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 Dec. 31, 1971, adjusted for stock splits, is $4.54 per share.
(1) The adjusted cost base for shares held on Jan. 31, 1988, was reduced by $0.75 per share following the Feb. 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 2021

Payment Date	Record Date	Ex-Dividend Date	Dividend
April 1, 2021	March 1, 2021	Feb. 26, 2021	$0.045
July 1, 2021	June 1, 2021	May 28, 2021	$0.045
Oct. 1, 2021	Sept. 1, 2021	Aug. 31, 2021	$0.045
Jan. 1, 2022	Dec. 1, 2021	Nov. 30, 2021	$0.050
April 1, 2022	March 1, 2022	Feb. 28, 2022	$0.050

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 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 $1.01 per share from and including June 30, 2017, to, but excluding, June 30, 2022.

Series E: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.30 per share from and including Sept. 30, 2017, to, but excluding, Sept. 30, 2022.

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 Sept. 30, 2019, to, but excluding, Sept. 30, 2024.

Preferred Share Dividends Declared in 2021

Series A

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2021	March 1, 2021	Feb. 26, 2021	$0.16931
June 30, 2021	June 1, 2021	May 31, 2021	$0.17981
Sept. 30, 2021	Sept. 1, 2021	Aug. 31, 2021	$0.17981
Dec. 31, 2021	Dec. 1, 2021	Nov. 30, 2021	$0.17981
March 31, 2022	March 1, 2022	Feb. 28, 2022	$0.17981

Series B

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2021	March 1, 2021	Feb. 26, 2021	$0.13186
June 30, 2021	June 1, 2021	May 31, 2021	$0.13108
Sept. 30, 2021	Sept. 1, 2021	Aug. 31, 2021	$0.13479
Dec. 31, 2021	Dec. 1, 2021	Nov. 30, 2021	$0.13970
March 31, 2022	March 1, 2022	Feb. 28, 2022	$0.13309

Series C

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2021	March 1, 2021	Feb. 26, 2021	$0.25169
June 30, 2021	June 1, 2021	May 31, 2021	$0.25169
Sept. 30, 2021	Sept. 1, 2021	Aug. 31, 2021	$0.25169
Dec. 31, 2021	Dec. 1, 2021	Nov. 30, 2021	$0.25169
March 31, 2022	March 1, 2022	Feb. 28, 2022	$0.25169

Series E

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2021	March 1, 2021	Feb. 26, 2021	$0.32463
June 30, 2021	June 1, 2021	May 31, 2021	$0.32463
Sept. 30, 2021	Sept. 1, 2021	Aug. 31, 2021	$0.32463
Dec. 31, 2021	Dec. 1, 2021	Nov. 30, 2021	$0.32463
March 31, 2022	March 1, 2022	Feb. 28, 2022	$0.32463

Series G

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2021	March 1, 2021	Feb. 26, 2021	$0.31175
June 30, 2021	June 1, 2021	May 31, 2021	$0.31175
Sept. 30, 2021	Sept. 1, 2021	Aug. 31, 2021	$0.31175
Dec. 31, 2021	Dec. 1, 2021	Nov. 30, 2021	$0.31175
March 31, 2022	March 1, 2022	Feb. 28, 2022	$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 10:30 a.m., Calgary time, on Thursday, April 28, 2022.

Transfer Agent
Computershare Trust Company of Canada
Suite 800, 324 - 8th Avenue SW
Calgary, Alberta T2P 2Z2

Phone
North America:
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.H, TA.PR.J

Additional Information
Requests can be directed to:

Investor Relations
TransAlta Corporation
110 - 12th Avenue SW
P.O. Box 1900, Station "M"
Calgary, Alberta T2P 2M1

Phone
North America:
1.800.387.3598 toll-free
Calgary/outside North America:
403.267.2520

Email
investor_relations@transalta.com
Fax
403.267.7405
Website
www.transalta.com

Shareholder Highlights

Ten-Year Total Shareholder Return vs. S&P/TSX Composite Index

Year ended Dec. 31 *($)*

	12	13	14	15	16	17	18	19	20	21
TransAlta	100	97	80	41	63	65	50	84	89	132
S&P/TSX	100	113	125	115	139	151	138	169	179	224

This chart compares what $100 invested in TransAlta and the S&P/TSX Composite Index at the end of 2012 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)*

	12	13	14	15	16	17	18	19	20	21
Market Value	15.12	13.48	10.52	4.91	7.43	7.45	5.59	9.28	9.67	14.05
Book Value	8.78	7.92	8.52	8.52	8.92	8.28	7.16	7.14	5.13	2.37

Data is from 2012 onwards.

Source: FactSet and TransAlta

Monthly Volume and Market Prices

2021

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Volume (millions)	19	15	20	7	12	13	11	11	12	11	9	8
TSX closing price *($ per share)*	11.22	11.12	11.90	12.08	10.93	12.35	13.01	12.36	13.38	13.88	12.99	14.05

Source: FactSet

Return on Common Shareholders' Equity

(%)

	12	13	14	15	16	17	18	19	20	21
ROE	(25.9)	(3.2)	6.3	(1.2)	5.4	(10.0)	(15.8)	3.3	(30.3)	(116.6)

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
President of TransAlta Renewables Inc.

Jane Fedoretz
Executive Vice President, People, Talent & Transformation

Shasta Kadonaga
Senior Vice President, Shared Services

Kerry O'Reilly Wilks
Executive Vice President, Legal, Commercial & External Affairs

Michael Novelli
Executive Vice President, Generation

Aron Willis
Executive Vice President, Growth

Blain van Melle
Executive Vice President, Alberta Business

Michelle Cameron
Vice President and Corporate Controller

Brent Ward
Senior Vice President, M&A, Strategy & Treasurer
Chief Financial Officer of TransAlta Renewables Inc.

Scott Jeffers
Vice President and Corporate Secretary

Glossary of Key Terms

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, Cascade, Ghost, Horseshoe, Interlakes, Kananaskis, Pocaterra, Rundle, Spray, Three Sisters, Bighorn and Brazeau hydro facilities.

Alberta Power Purchase Arrangement (Alberta PPA)
A long-term arrangement established by regulation for the sale of electric energy from formerly regulated generating units to PPA buyers in Alberta.

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.

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
Generation equipment's rated, continuous load-carrying ability, expressed in megawatts.

Carbon Tax
Sets a carbon price per tonne of GHG emissions related to transportation fuels, heating fuels and other small emission sources.

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.

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.

Combined Cycle
An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

Derate
To lower the rated electrical capability of a power generating facility or unit.

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.

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.

Heat Rate
A measure of conversion, expressed as British thermal units per Megawatt hour, of the amount of thermal energy required to generate electrical energy.

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.

MOA
Memorandum of Agreement.

NCIB
Normal Course Issuer Bid.

Pioneer Pipeline
The Pioneer gas pipeline jointly owned and operated by TransAlta and Tidewater Midstream and Infrastructure Ltd.

Power Purchase Agreement (PPA)
A long-term agreement established by regulation for the sale of electric energy to PPA buyers.

PPA Termination Payments
The Balancing Pool terminated the Sundance B and C Power Purchase Arrangements, and as a result, paid TransAlta $157 million in the first quarter of 2018 as well as an additional $56 million (plus GST and interest) on winning the arbitration against the Balancing Pool in the third quarter of 2019. Refer to the Significant and Subsequent Events section for further details.

REC
Renewable Energy Credits. 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 Injury Frequency (TIF)
Safety metric that tracks the total number of injuries, including minor first aids, relative to exposure hours worked.

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.

United Nations Sustainable Development Goals (UN SDGs)
The Sustainable Development Goals are the blueprint to achieve a better and more sustainable future for all. They address the global challenges we face, including poverty, inequality, climate change, environmental degradation, peace and justice.

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.

This report was printed in Canada. The paper, paper mills and printer are all certified by the Forest Stewardship Council, which is an international network that promotes environmentally appropriate and socially beneficial management of the world's forests.

TransAlta Corporation
110 - 12th Avenue SW
Box 1900, Station "M"
Calgary, Alberta
Canada T2P 2M1
403.267.7110
www.transalta.com

TransAlta™