GOVERNMENT OF ALBERTA

Annual Report

Energy

2021-2022

Energy, Government of Alberta | Energy 2021–2022 Annual Report

©2022 Government of Alberta | Published: June 2022
ISBN 978-1-4601-5430-4
ISSN 1703-4582

Note to Readers: Copies of the annual report are available on the Alberta Open Government Portal website www.alberta.ca

Table of Contents

Acronyms and Notations

ABC	Area-Based Closure
ACTL	Alberta Carbon Trunk Line
AER	Alberta Energy Regulator
AIOC	Alberta Indigenous Opportunities Corporation
APIP	Alberta Petrochemical Incentive Program
APMC	Alberta Petroleum Marketing Commission
ARP	Alberta Natural Gas Reference Price
AUC	Alberta Utilities Commission
bbl	Barrel
bbl/d	Barrels per day
BP	Balancing Pool
CAD$	Canadian Dollar
CCUS	Carbon Capture, Utilization and Storage
CEC	Canadian Energy Centre Limited
CER	Canadian Energy Regulator
CFR	Clean Fuel Regulation
COVID-19	Coronavirus 2019
CO2	Carbon Dioxide
CPC	Coal Policy Committee
EOR	Enhanced Oil Recovery
ER&T	Emerging Resources and Technologies Initiative
ESG	Environmental, Social and Governance
FIS	Field Inspection System
GBE	Government Business Enterprise
GIC	Governor in Council
GJ	Gigajoule
ha	Hectare
IAR	Integrated Application Registry
IEA	International Energy Agency
IEEP	Incremental Ethane Extraction Program
IRMS	Integrated Resource Management System
LAMAS	Land Automated Management System
km	Kilometre
LNG	Liquefied Natural Gas
MIM	Metallic and Industrial Minerals
MINRS	Metallic and Industrial Minerals Royalty Revenues
MOU	Memorandum of Understanding
MW	Megawatt
NGDDP	Natural Gas Deep Drilling Program
NGTL	TC Energy Corporation’s NOVA Gas Transmission Ltd.
OECD	Organization for Economic Co-operation and Development
OPEC	Organization of the Petroleum Exporting Countries
OWA	Orphan Well Association
PAA	Plastics Alliance of Alberta
PNG	Petroleum and Natural Gas
PPA	Purchasing Power Arrangement
REP	Renewable Electricity Program
RFPP	Request for Full Project Proposals
SCO	Synthetic Crude Oil
SLMS	Safety and Loss Management System
SMR	Small Modular (Nuclear) Reactors
SRP	Site Rehabilitation Program
SRT	Structured Review Tool
Tcf	Trillion cubic feet
TIER	Technology Innovation and Emissions Reduction
UPDP	Utility Payment Deferral Program
US$	United States Dollar
WCS	Western Canadian Select
WTI	West Texas Intermediate

Preface

The Public Accounts of Alberta are prepared in accordance with the *Financial Administration Act* and the *Fiscal Planning and Transparency Act*. The Public Accounts consist of the annual report of the Government of Alberta and the annual reports of each of the 20 ministries.

The annual report of the Government of Alberta contains Budget 2021 Key Results, the audited Consolidated Financial Statements and Performance Results, which compares actual performance results to desired results set out in the government's strategic plan.

This annual report of the Ministry of Energy contains the Minister's Accountability Statement, the ministry's Financial Information and Results Analysis, a comparison of actual performance results to desired results set out in the ministry business plan. This ministry annual report also includes:

- the financial statements of entities making up the ministry including the Alberta Energy Regulator, the Alberta Utilities Commission, the Alberta Petroleum Marketing Commission, the Post-Closure Stewardship Fund, the Balancing Pool and the Canadian Energy Centre Limited for which the minister is responsible; and
- other financial information as required by the *Financial Administration Act* and *Fiscal Planning and Transparency Act*, as separate reports, to the extent that the ministry has anything to report.

Each Ministry Annual Report should be considered along with the Government of Alberta Annual Report to provide a complete overview of government's commitment to openness, accountability and fiscal transparency.

Minister's Accountability Statement

The ministry's annual report for the year ended March 31, 2022, was prepared under my direction in accordance with the *Fiscal Planning and Transparency Act* and the government's accounting policies. All of the government's policy decisions as at June 3, 2022 with material economic or fiscal implications of which I am aware have been considered in the preparation of this report.

[Original signed by]

Honourable Sonya Savage
Minister of Energy

Message from the Minister

Following the upheavals experienced during the global pandemic, the Government of Alberta remains focused on strengthening the province's economy to ensure prosperity for all Albertans. Looking back on 2021-22, it is remarkable to see how resilient Alberta and Albertans have been throughout this historic period. After a challenging year, we have put ourselves in a position to thrive by implementing the actions outlined in Alberta's Recovery Plan and ensuring new opportunities for every Albertan.

Alberta's world-leading energy industry has a critical role to play in growing our resources and diversifying the economy. Over the past year, we've taken significant steps that will support the industry as the economy continues to rebound and we look to the future. Oil and gas will play an integral role in meeting energy demands while we pursue innovation in emissions reduction technologies, as well as integrate renewables and other lower-carbon sources into the mix.

Some of the new initiatives Alberta Energy launched last year include emerging opportunities built on the success of our traditional oil and gas sector. Renewing Alberta's Mineral Future is Alberta's minerals strategy and action plan to capitalize on our untapped geological potential. Critical and rare earth minerals are needed for the technologies in a low-carbon future and we have the resources, expertise and determination to position Alberta as a preferred mineral producer and supplier. To support the strategy and action plan, the *Mineral Resource Development Act* was passed to set up the Alberta Energy Regulator as the full lifecycle for Alberta's mineral resources.

The Associate Minister of Natural Gas and Electricity released the Hydrogen Roadmap, a key part of the Natural Gas Vision and Strategy, and our path to establishing Alberta as a leader in the global clean hydrogen economy while maintaining our reputation as an international supplier of responsible, high-quality energy products. Our province is already the largest producer of hydrogen in Canada and we are poised to be an important player in this multi-trillion dollar opportunity.

Alberta – in collaboration with Ontario, Saskatchewan and New Brunswick – agreed to a joint strategic plan outlining the path forward on small modular reactors that could provide safe, reliable and zero-emissions energy to power our growing economy and population.

To further geothermal development in the province, the Alberta Energy Regulator was established as the lifecycle geothermal regulator to administer and issue geothermal tenure rights. Companies have expressed interest in exploring Alberta's geothermal potential. The department has received tenure applications and granted the first geothermal leases for the exploration and development of Alberta's geothermal resources.

We continue to invest in carbon capture, utilization and storage technology as it is critical to clean hydrogen development, low carbon oil sands development, petrochemicals, and other large emission industries. The province is advancing a strategic hub concept to sequester emissions underground through a competitive process.

In addition to setting the course for the future success of Alberta's energy sector, we continued to successfully administer programs to ensure good jobs for Albertans. The Site Rehabilitation Program has been a triumph for Alberta. As of May 15, 2022, $1 billion in grant funding has been allocated to more than 500 Alberta-based companies, creating more than 4,700 jobs for hard-working Albertans.

The Site Rehabilitation Program (SRP) is also a good example of how our government ensures Indigenous communities play a meaningful role in Alberta's post-pandemic energy strategy. The program targeted a total of $133 million to clean up inactive oil and gas sites on or near Indigenous communities. As of May 11, 2022, approximately 11,952 applications submitted by 104 different Indigenous contractors have been approved since the start of the program. In addition, the government is proud to have collaborated with Indigenous businesses, the Indian Resource Council and the Métis Settlements General Council to develop the details of Period 6 of the SRP.

The Alberta Indigenous Opportunities Corporation (AIOC) has made great strides in supporting Alberta's economic recovery while partnering in prosperity with Indigenous Peoples in Alberta. The AIOC can provide up to $1 billion in loan guarantees to reduce the cost of capital for Indigenous groups, and to support their ability to raise capital to invest in natural resource projects. For example, the AIOC is providing a loan guarantee to backstop an investment by six First Nations in the Cascade Power Project, which will add up to eight per cent electricity to Alberta's power grid. Another example is a $40 million loan guarantee to support eight Indigenous communities in the Wood Buffalo region in financing their portion of a 15 per cent ownership interest in the Northern Courier Pipeline System.

We have seen sustained interest in the Alberta Petrochemical Incentive Program. Projects that have submitted initial applications so far represent over $25 billion in total investment, representing over 66,000 potential construction jobs, and over 2,100 permanent jobs. We are hopeful that we will see more project approvals as the submissions continue through the application process.

We are also proud to say that Alberta Energy has taken significant action to reduce tape and – together with our agencies – have achieved 22 per cent in reductions, exceeding our target of 20 per cent for 2021-22. The cutting of red tape is helping to create cost and time savings for industry, and we are committed to making further improvements.

Things are looking up for our energy industry. However, we cannot dismiss that rising energy bills have been an added burden for Alberta families. That's why we moved quickly to set up the Natural Gas Rebate Program to provide an innovative energy rebate program for next winter to help Albertans manage higher heating costs. We also unveiled an Electricity Rebate Program to provide $150 in electricity rebates ($50 rebate for three months) to more than over 1.9 million homes, farms and businesses.

The rising cost of electricity and natural gas is an indicator of the volatility in the world's energy markets. Recent global events – such as the unnecessary and violent Russian invasion of Ukraine – have made it clear: energy security is critical. There is a global need for responsible energy partners. Alberta can be part of the solution. We are a safe, secure and responsible energy producer and supplier, and we can lead a balanced discussion on energy security so that we are prepared should another event adversely and significantly affect the global energy supply. Energy security is necessary to ensure long-term affordable and reliable energy for everyone.

Alberta's government will continue to stand up for the energy sector and for Albertans. We continue to advocate to get our high-quality product to market. Our energy products are produced under some of the highest environmental, labour and human rights standards in the world. Combined with our efforts to reduce emissions and develop emerging sources, we are in a stellar position to help meet energy demands at home and around the world.

I want to recognize the passionate team at the department that works tirelessly every day to represent and defend Alberta´s interests. They too are everyday Albertans who want the best for the future generation. I am grateful for their dedication and commitment to this province.

As we emerge from the pandemic, we should take the time to recognize the challenges we have overcome and celebrate what we have achieved. It cannot be understated that Alberta's ability to persevere is second-to-none. With Alberta's economy on the rebound, we are prepared to tackle whatever comes next. The work ahead will be filled with challenges, especially around strengthening global energy security, but we are already taking advantage of the emerging opportunities to future-proof and diversify the energy sector. Alberta is headed in the right direction and even brighter opportunities are on the horizon.

[Original signed by]

Honourable Sonya Savage
Minister of Energy

Management's Responsibility for Reporting

The Ministry of Energy includes:

- Department of Energy,
- Alberta Energy Regulator,
- Alberta Utilities Commission,
- Alberta Petroleum Marketing Commission,
- Post-Closure Stewardship Fund,
- Balancing Pool, and
- Canadian Energy Centre Ltd.

The executives of the individual entities within the ministry have the primary responsibility and accountability for the respective entities. Collectively, the executives ensure the ministry complies with all relevant legislation, regulations and policies.

Ministry business plans, annual reports, performance results and the supporting management information are integral to the government's fiscal and strategic plan, annual report, quarterly reports and other financial and performance reporting.

Responsibility for the integrity and objectivity of the accompanying ministry financial information and performance results for the ministry rests with the Minister of Energy. Under the direction of the Minister, as senior executives, we oversee the preparation of the ministry's annual report, which includes the financial information, performance results on all objectives and initiatives identified in the Ministry Business Plan and performance results for all ministry-supported commitments that were included in the 2021-24 Government of Alberta Strategic Plan. The financial information and performance results out of necessity, include amounts that are based on estimates and judgments. The financial information is prepared using the government's stated accounting policies, which are based on Canadian public sector accounting standards. The performance measures are prepared in accordance with the following criteria:

- Reliable – information used in applying performance measure methodologies agrees with the underlying source data for the current and prior years' results.
- Understandable – the performance measure methodologies and results are presented clearly.
- Comparable – the methodologies for performance measure preparation are applied consistently for the current and prior years' results.
- Complete – outcomes, performance measures and related targets match those included in the ministry's Budget 2021.

As senior executives, in addition to program responsibilities, we are responsible for the ministry's financial administration and reporting functions. The ministry maintains systems of financial management and internal control which give consideration to costs, benefits, and risks that are designed to:

- provide reasonable assurance that transactions are properly authorized, executed in accordance with prescribed legislation and regulations, and properly recorded so as to maintain accountability of public money;
- provide information to manage and report on performance;

- safeguard the assets and properties of the province under ministry administration;
- provide Executive Council, the President of Treasury Board, Minister of Finance, and the Minister of Energy the information needed to fulfill their responsibilities; and
- facilitate preparation of ministry business plans and annual reports required under the *Fiscal Planning and Transparency Act*.

In fulfilling our responsibilities for the ministry, we have relied, as necessary, on the executives of the individual entities within the ministry.

[Original signed by]

Grant Sprague, Q.C.
Deputy Minister of Energy

[Original signed by]

Adrian Begley
Chief Executive Officer
Alberta Petroleum Marketing Commission

[Original signed by]

Carolyn Dahl Rees
Chair
Alberta Utilities Commission

[Original signed by]

Laurie Pushor
President and Chief Executive Officer
Alberta Energy Regulator

[Original signed by]

Tom Olsen
Chief Executive Officer and Managing Director
Canadian Energy Centre Ltd.

[Original signed by]

Sandra Scott
President and Chief Executive Officer
Balancing Pool

June 3, 2022

Results Analysis

Table of Contents

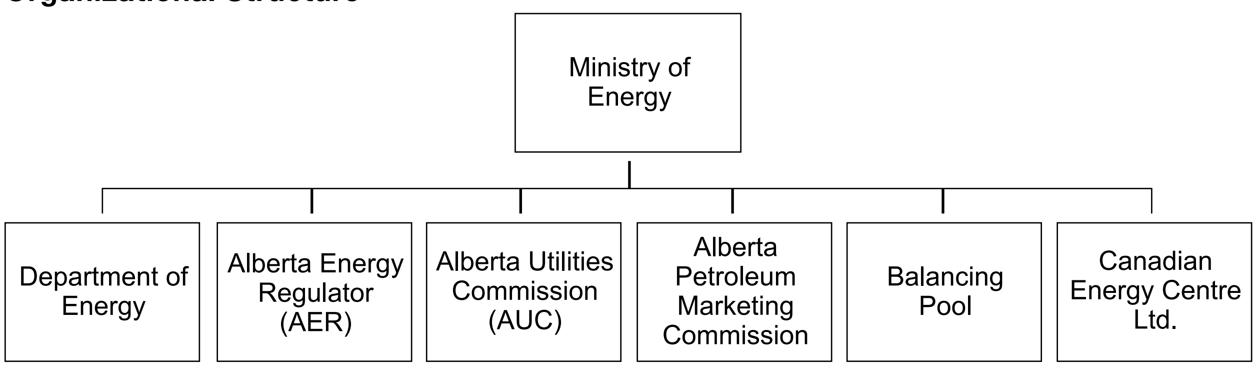
Ministry Overview

The Ministry of Energy manages Alberta's energy and mineral resources to ensure they are developed responsibly, in a way that benefits and brings value to Albertans. The ministry strives to ensure sustained prosperity in the interests of Albertans through the stewardship of energy and mineral resources. This includes having high regard for the social, economic and environmental impacts of Alberta's energy development.

The ministry encompasses the Department of Energy, the Alberta Energy Regulator, the Alberta Utilities Commission, the Alberta Petroleum Marketing Commission, the Balancing Pool and the Canadian Energy Centre. Each entity plays an important role in overseeing the orderly development of Alberta's energy and mineral resources.

A more detailed description of Energy and its programs and initiatives can be found at: www.alberta.ca/energy.

Organizational Structure



Note: The Post-Closure Stewardship Fund is a regulated fund that is administered by the department

The outcomes in Energy's 2021-24 Business Plan are:

- Albertans benefit from investment in responsible energy and mineral development and access to global markets.
- Effective, efficient stewardship and regulation of Alberta's energy and mineral resources.

Department of Energy

- Acts as the steward of Alberta's energy and mineral resources on behalf of all Albertans.
- Develops and administers policies and programs to guide the management and development of Alberta's non renewable resources, including conventional and unconventional oil and gas; oil sands; coal; metallic and industrial minerals, and petrochemicals.
- Ensures the integration of energy and mineral policies and serves as an interface between policy development and policy assurance.
- Grants industry the rights to explore and develop Alberta's Crown-owned energy and mineral resources, subject to regulatory approvals.

- Establishes, administers and monitors the effectiveness of Alberta's royalty systems for Crown-owned energy and mineral resources.
- Collects revenues from the development of Alberta's energy and mineral resources on behalf of Albertans.
- Establishes the framework for responsible industry led investment in electricity infrastructure and markets for the reliable delivery of electricity to consumers.
- Leads Alberta's market access efforts with internal, external and international stakeholders.
- Administers the carbon capture and storage Post-Closure Stewardship Fund.

Alberta Energy Regulator

- Independently makes regulatory decisions regarding upstream petroleum, natural gas, bitumen and coal development in accordance with applicable legislation and regulations, and within the framework of Alberta's overall energy policy.
- Responds to changes in the energy industry while providing regulatory certainty for investors and the public, including assurance that risks are appropriately mitigated throughout the life cycle of energy projects.
- Provides for the safe, efficient, orderly, and environmentally responsible development of energy resources.
- Provides geoscience information, evaluation and advice through the Alberta Geological Survey to support the exploration, resource appraisal, sustainable development, regulation, and conservation of Alberta's resources.

Alberta Utilities Commission

- Regulates investor owned electric, natural gas and water utilities, and certain municipally owned electricity utilities to ensure customers receive safe and reliable utility service at just and reasonable rates.
- Independently makes decisions on the need, siting, construction, alteration, operation and decommissioning of natural gas utilities' facilities and electricity transmission facilities.
- Regulates power plants in a similar fashion, except the need for new power plants, which is determined by market forces.
- Develops and amends rules that support the orderly operation of the retail natural gas and electricity markets, and adjudicates on market and operational rule contraventions that the Market Surveillance Administrator may bring before the Alberta Utilities Commission.
- Ensures that the delivery of Alberta's utility services takes place in a manner that is fair, responsible and in the public interest.

Alberta Petroleum Marketing Commission

- Markets the Crown's conventional crude oil royalty barrels received in lieu of cash royalties.
- Determines prices used in the valuation of the Crown's royalty share of natural gas, natural gas liquids, and sulphur.
- Assists with the development of new energy markets and transportation infrastructure.
- Responsible for the stewardship of the Sturgeon Refinery processing agreement and other commercial contracts.
- Evaluates strategic proposals for adding value to Alberta's resources.

Balancing Pool

- Acts as a buyer for the Power Purchase Arrangements (PPAs) that were not sold in the public auction held by the Government of Alberta in 2000 or that have subsequently been terminated by third party buyers, and manages the resulting electricity portfolio and/or terminates the PPAs with the owners where feasible.
- Allocates or collects any forecast cash surplus or deficit to and from electricity consumers in Alberta in annual amounts over the life of the Balancing Pool.
- Holds the Hydro Power Purchase Arrangement and manages the associated stream of receipts or payments.

Canadian Energy Centre

- Promotes Canada as the supplier of choice for the world's growing demand for responsibly produced energy.
- Responds to misinformation about Canadian oil and natural gas.
- Creates content to improve the general understanding of Canada's energy sector.
- Centralizes and analyses data that targets investors, researchers and policy makers.

Alberta Energy Resource Sector

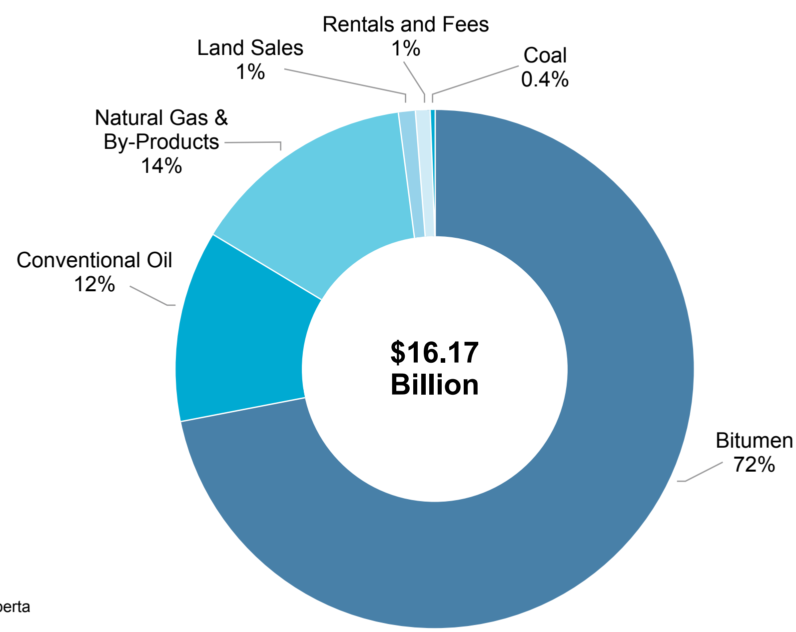
Non-Renewable Resource Revenue

Energy development in Alberta provides investment, jobs, business opportunities, taxes and royalty revenues that fund important government programs for the province. Energy development also drives activity in a number of other industries, including construction and manufacturing, which benefits communities across Alberta and Canada.

Non-Renewable Resource Revenue Generated[1]

The department is responsible for collecting non-renewable resource revenue on behalf of Albertans. Royalties are payments to Albertans for Crown-owned resources that are produced and sold. Albertans, as owners, collect value from our resources through royalties, bonuses and lease rentals. The price received and the costs involved in producing and selling those resources affect the value available for royalties.

2021-22 Non-Renewable Resource Revenue



Source: Government of Alberta

Non-renewable resource revenues totaled around $16.17 billion in the 2021-22 fiscal year, about $13.27 billion higher than the budgeted amount of $2.9 billion, and almost $13.1 billion higher than the 2020-21 actual. This substantial increase in non-renewable resource revenues was a result of significantly higher West Texas Intermediate prices for the fiscal year, which impacted bitumen and conventional oil royalties. A higher Alberta Reference Price for natural gas also significantly increased gas royalties. Higher prices for oil had an upward impact on natural-gas-liquids prices and gas royalties, since prices for natural gas by-products follow oil prices.

[1] Note: some totals may not add up due to rounding

Factors Impacting Non-Renewable Resource Revenue

Non-renewable resource revenue is impacted by multiple factors. The most influential factor affecting non-renewable resource revenue is commodity prices, but also includes global economic conditions, economic growth, demand trends and supply levels. Other factors such as capital and operating costs, the U.S. - Canadian dollar exchange rate, and production also affect royalty revenues. Unanticipated changes in these factors can result in significant differences between the budget, forecasts and the actual results.

Treasury Board and Finance is responsible for forecasting non-renewable resource revenue. The Government of Alberta models the complex system to calculate royalties and forecast non-renewable resource revenue. To develop price forecasts, as part of its analysis, the government considers a number of industry consultants and the futures market, as well as a deep analysis of global, North American and Alberta market fundamentals.

The non-renewable resource revenue forecast can change frequently throughout the year as new price, cost and production forecasts are issued. When the market is changing rapidly, price outlooks are frequently updated and the government incorporates recent market trends to reflect those rapid developments in a timely manner. Changes in production forecasts and other variables such as industry costs and investments are also incorporated into each quarterly update.

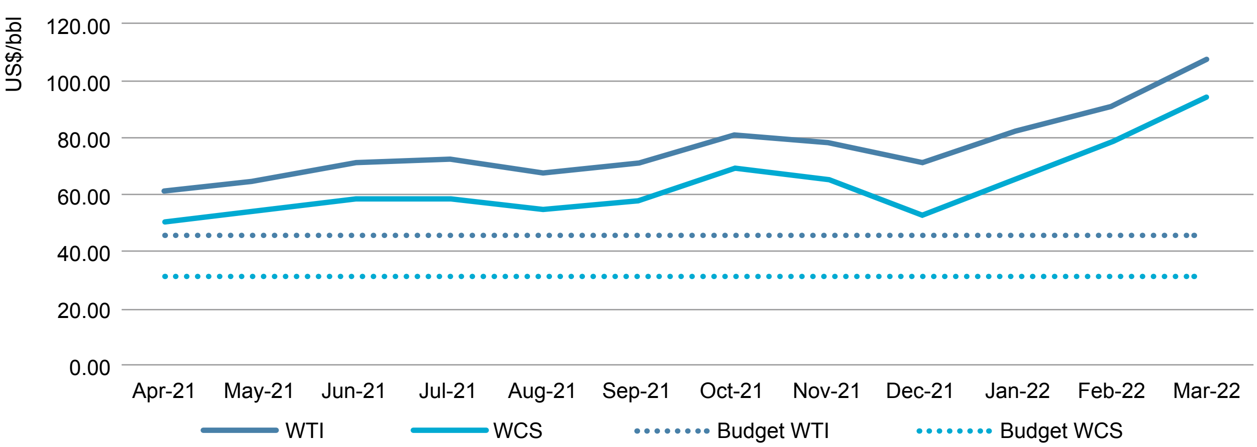
Commodity Prices and Trends[2]

Commodity Prices	2021-22 Budget	2021-22 Actual
WTI (US$/bbl)	46.00	77.03
Exchange rate	77.40	79.79
Light-Heavy differential (US$/bbl)	14.60	13.56
WCS (US$/bbl)	31.40	63.47
Alberta reference price for natural gas (CAD$/GJ)	2.60	3.48

Oil Prices

Oil price differences are affected by crude quality (a range from light sweet and heavy sour oils), location, market demand, and access to markets for these products. Alberta is landlocked and exports both light and heavy crude oil. However, most of Alberta's oil production growth and oil exports are from heavy crude, for which price per barrel is discounted compared to light sweet prices.

2021-22 Crude Oil Prices



Source: Government of Alberta

[2] Note: WCS data is reported in Canadian currency in the Government of Alberta budget documents. To allow for comparisons with other price data in this annual report, WCS has been converted to U.S. currency. Conversions may differ slightly, depending on the treatment of exchange rates.

Oil prices increased in 2021-22 and reached a seven-year high in February 2022 as the demand growth outpaced the supply growth. In 2021, the demand gradually recovered with eased global COVID-19 restrictions, while the spare production capacity was limited due to the lack of upstream investments over the past few years. On February 24, 2022, Russia invaded Ukraine, and the subsequent sanctions on Russia raised the specter of a prolonged disruption to the oil supply.

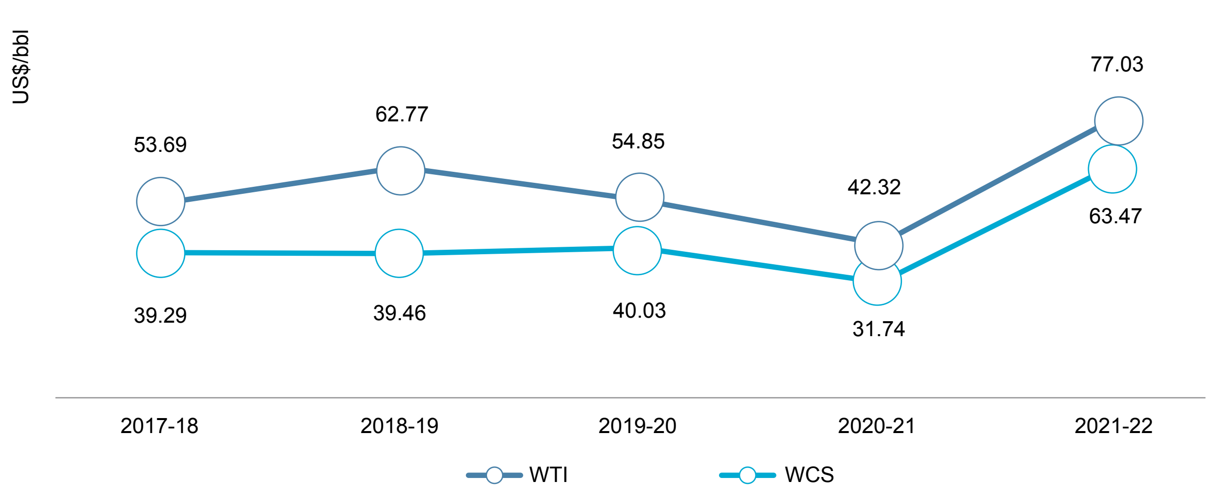
West Texas Intermediate (WTI) is the North American price benchmark for light sweet oil. Western Canadian Select (WCS) is a North American price benchmark for heavy crude oil, commonly used to price Canadian heavy oil.

WTI 2021-22 trend: Budget 2021 was based on an estimate of US$46.00 per barrel price for WTI crude oil and an exchange rate of 77.40 cents U.S. to the Canadian dollar in 2021-22. The actual WTI price averaged US$77.03 per barrel in 2021-22, with an exchange rate of 79.79 cents U.S. to the Canadian dollar. This was a significant increase from US$42.32 per barrel in 2020-21, primarily due to the tightened crude oil market, or the market in which the demand became relatively more insensitive to price. The fourth quarter of the 2021-22 fiscal year in particular witnessed a strong upward trend in the WTI price, as intensified geopolitical risks temporarily outweighed the impact of the potential COVID-19 outbreak. In March 2022, the WTI price increased to US$108.26, which was the highest monthly WTI price since April 2011.

WTI five-year trend: In 2021-22, the average WTI price was at its highest level during the past five fiscal years. With strong upward pressures, especially towards the end of the fiscal year, the 2021-22 price settled at US$77.03.

The International Energy Agency (IEA) suggested that the Organization for Economic Co-operation and Development (OECD) crude inventories are at the lowest level since 2014 in its March 2022 Oil Market report. In addition, the Organization of Petroleum Exporting Countries and its allies (OPEC+) remained on its path to increase production by around 400,000 bpd per month until September 2022, which is considered limited to filling the gap caused by Russian crude sanctions. The WTI price is expected to remain volatile in the short term with low inventory levels, low spare production capacity, and intensifying geopolitical risks.

Crude Oil Prices



Source: Government of Alberta

WCS 2021-22 trend: The WCS price was estimated at US$31.40 per barrel for 2021-22 in Budget 2021. WCS price increased significantly to US$63.47 per barrel in 2021-22, as elevated global crude oil prices kept the outright prices for Canadian grades high. WCS started the 2021-22 fiscal year at US$50.51 per barrel as the global crude oil demand gradually recovered, and the OPEC and some non-OPEC producers reached an agreement to balance global supply and demand. The WCS increased towards the end of the fiscal year, due to the growing demand for crude oil, as the fear of the pandemic declined and the impact of the Omicron variant was perceived as relatively mild. The Russia-Ukraine war further contributed to the increase in the global crude oil prices, and WCS reached US$94.57 in March 2022.

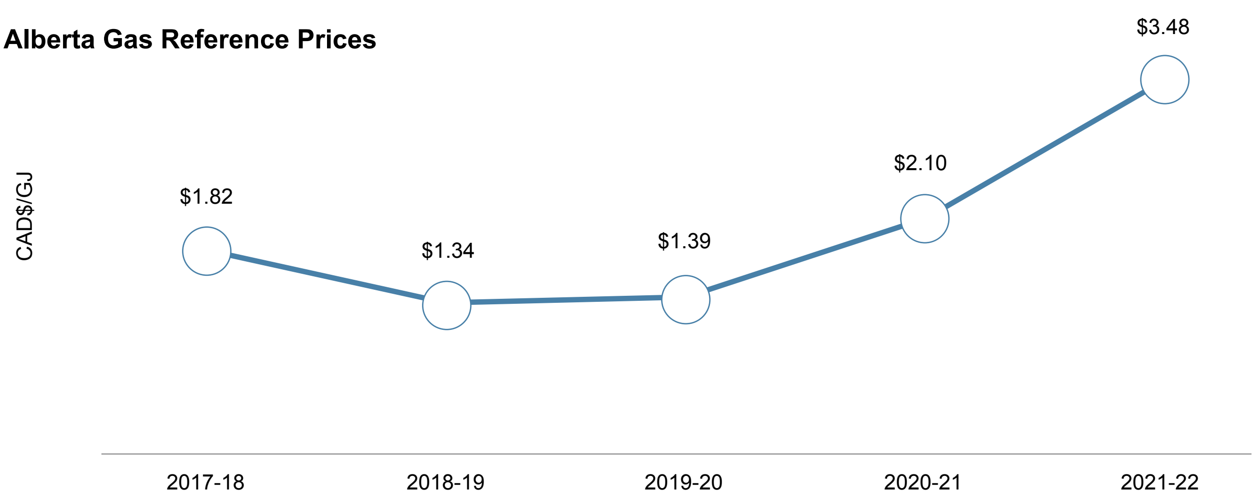
WCS five-year trend: The WCS price has experienced a significant increase during the 2021-22 fiscal year, with the average annual WCS price settling at US$63.47. The WCS price for 2021-22 was higher than the average annual WCS prices in all other fiscal years during the period from 2017-18 to 2021-22. The supply growth in Western Canada is no longer as constrained by takeaway capacity after Enbridge Line 3, which has a total capacity of 760,000 bpd, began operation in October 2021. Alberta heavy crude exports to the U.S. Gulf Coast have been increasing over time as traditional heavy crude providers like Venezuela and Mexico are struggling to raise output. The increase of international crude oil prices at the beginning of 2022, driven by intensified geopolitical risks, also significantly pushed up the WCS prices. WCS prices started to recover during 2021 with improving global WTI oil prices. The WCS price received an additional uplift from the increased pipeline capacity and reduction in Russian crude oil supply due to sanctions, bringing the WCS price to an average US$63.47 per barrel in 2021-22, which was a significant recovery from US$31.74 per barrel during the 2020-21 fiscal year.

Natural Gas Prices

The Alberta Natural Gas Reference Price (ARP) is used in natural gas royalty formulas for natural gas royalty revenue calculation.

Overall, the general rule of supply and demand balance determines natural gas prices in North America. Storage levels and weather patterns also affect prices as these factors impact the market's ability to respond to additional demand. Lower storage levels could lead to higher prices and vice-versa. Lower than normal temperatures in the winter and higher than normal temperatures in the summer could lead to increased demand and higher prices.

Alberta Gas Reference Prices

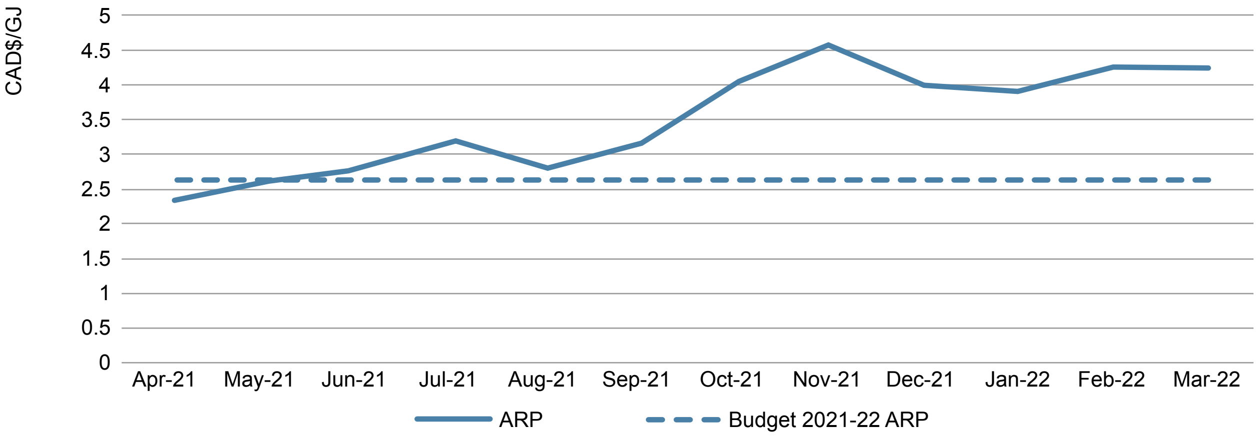


Source: Government of Alberta

Royalties in Budget 2021 were based on a gas price forecast of ARP at CAD$2.60/gigajoule (GJ). The realized ARP averaged CAD$3.48/GJ in the fiscal year 2021-22. The actual gas price was above budgeted levels at the end of the fiscal year due to a combination of strong domestic and export demand, and extreme cold winter weather conditions, which induced strong heating demand.

Furthermore, North America is becoming more integrated into world markets through U.S. liquefied natural gas (LNG) exports. Global gas market trends continue to affect the Western Canadian gas market, including the U.S. becoming a large LNG exporter. Increasing LNG export demand from the U.S. will potentially allow Canadian gas supply to fill the supply gap in the North American markets; therefore, Alberta's gas is in a position to serve some undersupplied regional markets.

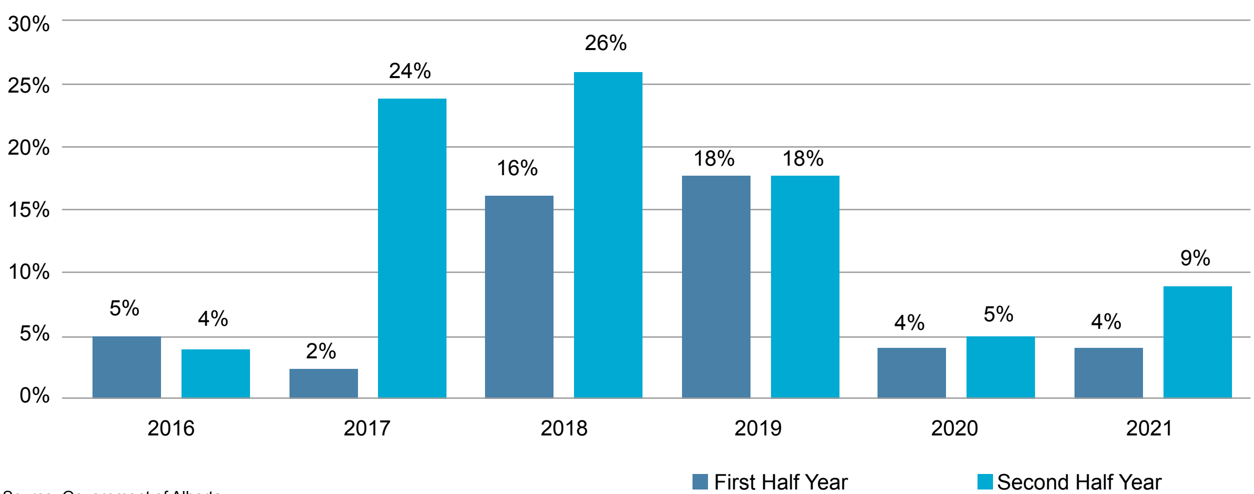
2021-22 Alberta Gas Reference Prices



Source: Government of Alberta

Measuring the AECO price volatility helps to identify if further regulatory intervention is required. While some volatility in a market reflects a functional market balancing supply and demand dynamics, excessive volatility can result from insufficient market regulation. Assessing with a semi-annual frequency strikes a balance between responding to market volatility, while not overreacting to short-term swings.

Average Daily AECO Price Change



Source: Government of Alberta

During 2016 and the first half of 2017, market volatility was low, under five per cent, and representative of a stable natural gas market. From the second half of 2017 through the second half of 2019, market volatility was much higher. The increase in market volatility in the second half of 2017 coincided with infrastructure issues and restriction protocol on the Nova Gas Transmission Ltd. (NGTL) system.

The subsequent decrease in volatility from 2019 to 2020 coincided with the introduction of the temporary service protocol in October of 2019. The temporary service protocol prioritizes delivery and storage injection on the NGTL system during planned outage and maintenance periods. Volatility remained low in 2020, reflecting a natural gas market with improved stability.

The spot AECO price experienced some volatility in late summer 2021, mainly due to planned and unplanned maintenance, and construction activities on the NGTL system, limiting access to export destinations and storage facilities. As such, AECO pricing was observed to disconnect with Dawn (Eastern Canadian benchmark) and Henry Hub prices on a few occasions.

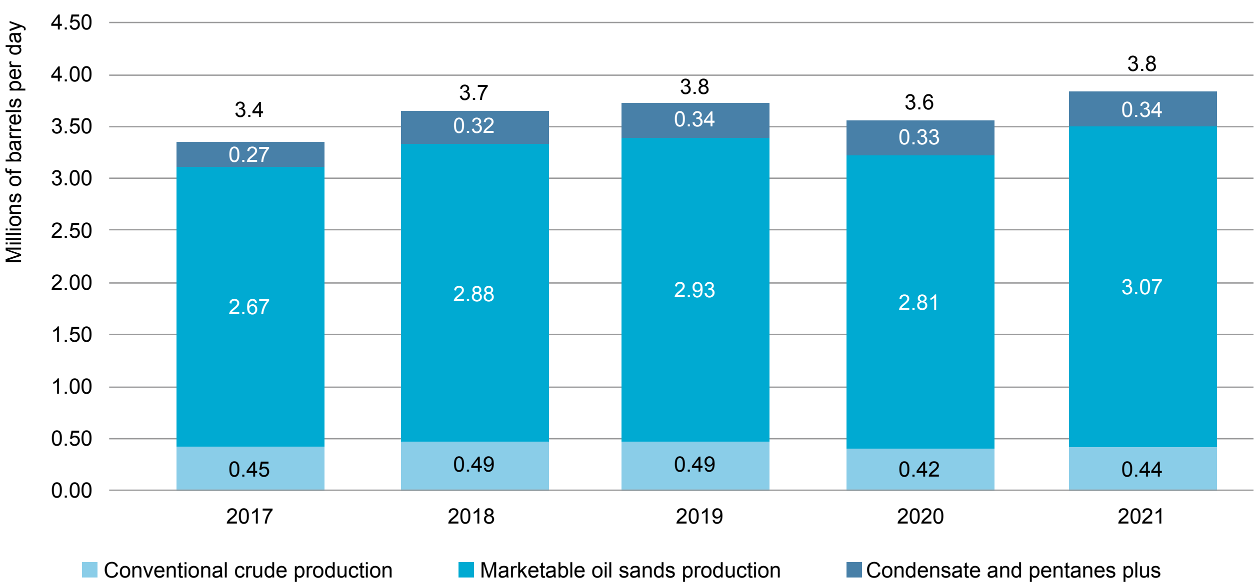
Volatility to AECO spot pricing is normal during planned summer maintenance on NGTL. During the second half of 2021, AECO did exhibit more volatility compared to Henry Hub and Dawn. However, the volatility was much smaller compared to the AECO prices prior to 2020.

Production: Performance Indicator 1.b[3]

Alberta Crude Oil and Equivalent Production

Alberta's crude oil and equivalent production consists of conventional crude oil production, marketable oil sands production, which consists of non-upgraded bitumen and upgraded bitumen, and condensate and pentanes plus.

Alberta Crude Oil and Equivalent Production



Source: Alberta Energy Regulator

[3] Note: Further information on sources and methodology for this performance indicator can be found in the Performance Measure and Indicator Methodology section on page 86.

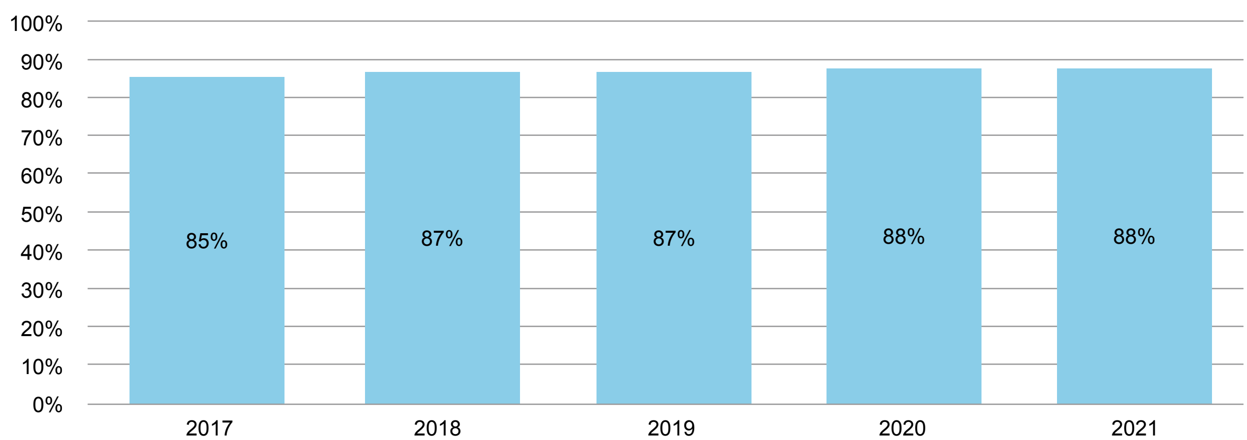
Marketable oil sands production comprises a significant majority of Alberta's crude oil and equivalent production. Over the 2017-2021 period, the share of marketable oil sands production in the province remained in the approximate range of 78 to 80 per cent of the total crude oil and equivalent production. In 2020, oil sands production in Alberta declined due to the impacts of COVID-19 pandemic, which significantly affected crude oil demand in Alberta's traditional market, the United States. However, in 2021, oil sands production increased by about 9 per cent from the 2020 level. The increase took place as the impacts of COVID-19 pandemic in 2021 were less pronounced than in 2020. The demand for oil, including the demand in the United States, experienced some recovery. COVID-19 mitigation measures and safety practices at the oil sands facilities were also well in place by 2021, minimizing any disruptions, which helped to increase production. In 2021, marketable oil sands production reached an all-time record of approximately 3.07 million bpd, exceeding the average annual production of 3 million barrels per day for the first time ever. It should be noted that marketable oil sands production is different from crude bitumen production, as some volumes are reduced during the upgrading process; therefore, the overall marketable oil sands production volumes are lower than overall crude bitumen production volumes.

Even though the share of conventional crude oil production as a per cent of total crude oil and equivalent production, at about 11 per cent, reached its lowest level in 2021 for the entire 2017 – 2021 period, the actual conventional crude oil production increased from about 0.42 million bpd in 2020 to 0.44 million bpd in 2021. Conventional crude oil production in Alberta remained in the approximate 0.42 million bpd – 0.49 million bpd range during the 2017-2021 period; during this period, it was at its lowest level, at 0.42 million bpd in 2020, and peaked at 0.49 million bpd in 2018.

The production of condensate and pentanes plus increased by about 4 per cent from 2020 to 2021, from about 0.33 million bpd in 2020 to 0.34 million bpd in 2021. The total production of condensate and pentanes plus remained fairly stable over the 2019 – 2021 period, as decreases in condensate production were counter-balanced by increases in the production of pentanes. During the entire 2017-2021 period, the lowest level of production was in 2017, at 0.27 million bpd, and the highest – in 2021. In 2021, the total production of condensate and pentanes plus in the province reached an all time annual record level.

Alberta also accounts for a significant majority of Canada's crude oil and equivalent production. According to the Canada Energy Regulator, in 2021, total Alberta crude oil and equivalent production was estimated to account for 81.9 per cent of total Canadian production. This represented an increase from the 2020 share of 80.4 per cent of Canadian production. Over the 2017-2021 period, Alberta's share of Canadian production was generally consistent at around 80 per cent, ranging from about 80.4 per cent in 2020 to 81.9 per cent in 2021.

Total Percentage of Crude Oil and Equivalent Leaving Alberta



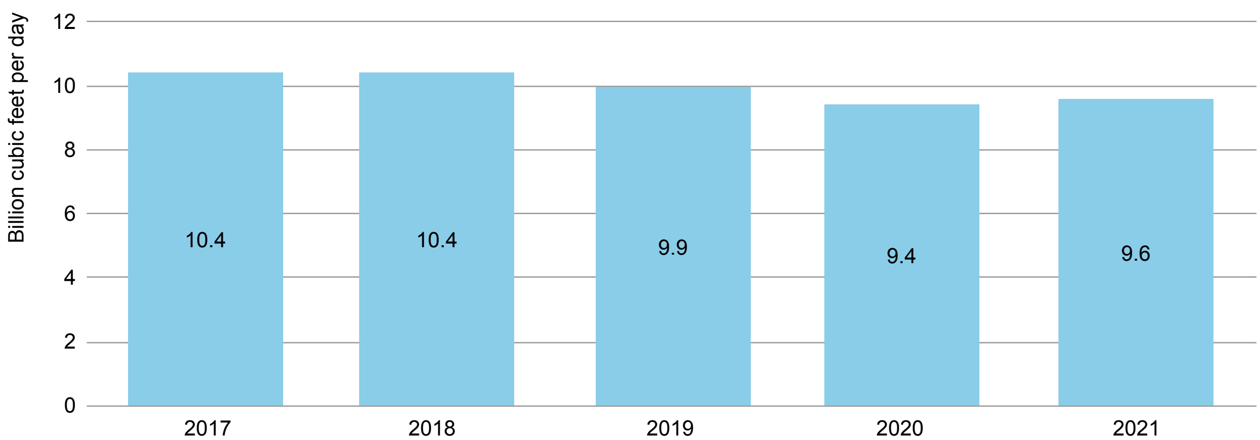
Source: Alberta Energy Regulator

The significant majority of Alberta oil disposition goes to the United States and other Canadian jurisdictions. In 2021, about 88 per cent of Alberta's total crude oil disposition left the province, which is generally in line with the 2020 result. During the entire 2017-2021 period, more than 85 per cent of all Alberta crude oil disposition left the province every year.

Natural Gas Production

From 2020 to 2021, marketable natural gas production increased approximately 2.5 per cent, with a 0.2 billion cubic feet per day increase from 9.4 billion cubic feet per day in 2020 to 9.6 billion cubic feet per day in 2021.

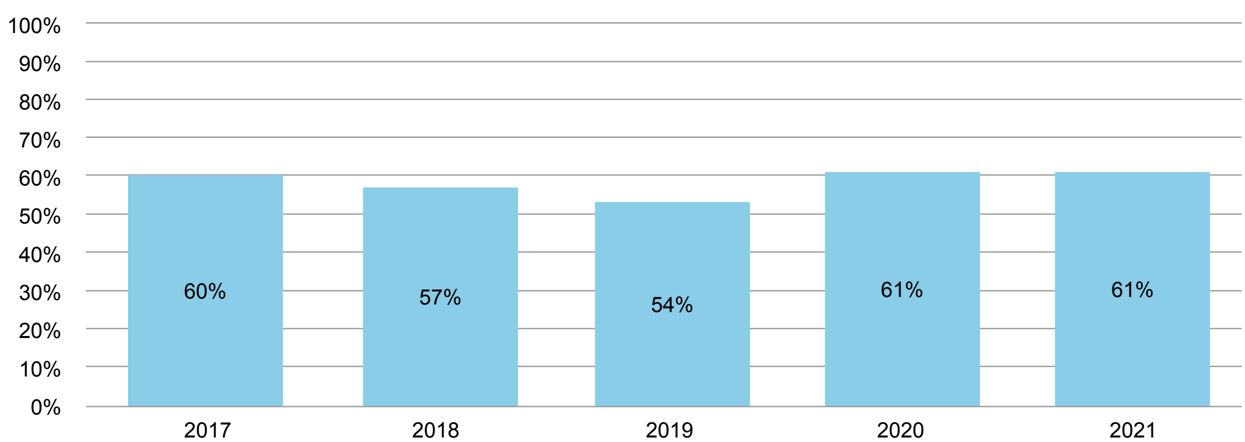
Alberta Marketable Gas Production



Source: Alberta Energy Regulator

Alberta accounts for a majority of Canada's marketable natural gas production. In 2021, according to the Canada Energy Regulator, Alberta accounted for an estimated 62.4 per cent of total Canadian production. Even though Alberta's production level increased from 2020 to 2021, Alberta's 2021 production represented a decline in the national share of production from 62.9 per cent in 2020. Over the 2017-2021 period, Alberta accounted for approximately two-thirds of Canadian production, ranging from 62.4 per cent in 2021 to 67.9 per cent in 2017. Alberta's share of Canadian production was declining every year over the 2017-2021 period, with the share of British Columbia increasing.

Total Percentage of Gas Leaving Alberta



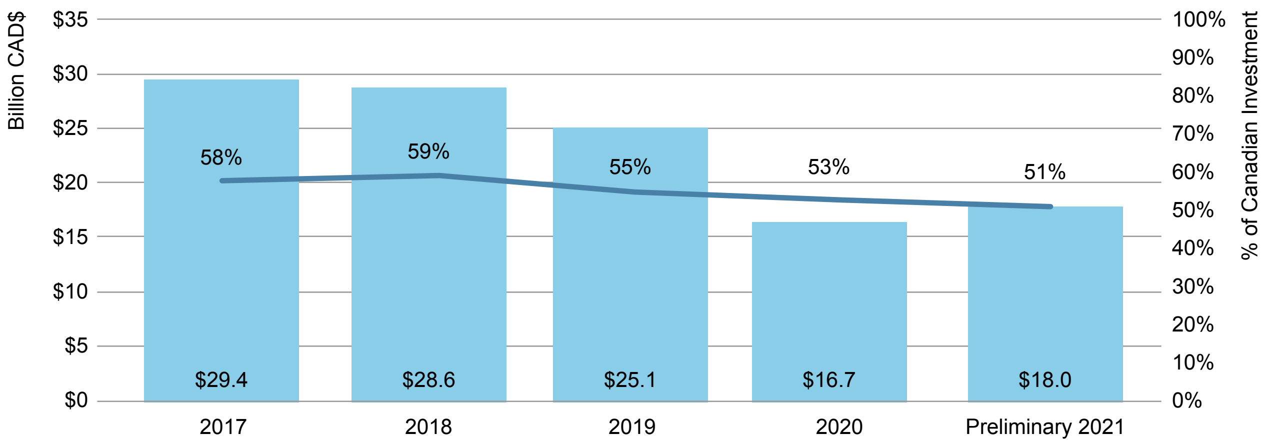
Source: Alberta Energy Regulator

In 2021, a majority of Alberta's total gas disposition, about 61 per cent, was exported to the rest of Canada (27 per cent) and the United States (33 per cent)[4]. In 2021, share of gas disposition leaving the province was virtually the same as in 2020.

Investment: Performance Indicator 1.c[5]

Upstream energy investment in Alberta consists of mining, quarrying, conventional oil and gas investment, oil sands investment, as well as support activities. Alberta has to compete for investment with other oil and gas producing jurisdictions to ensure continuous development of its energy industry.

Capital Investment in Alberta
Mining, Quarrying, and Oil & Gas Extraction Sector



Source: Statistics Canada

Total upstream energy industry investment in Alberta for 2020 was $16.7 billion, accounting for about 53 per cent of the Canadian upstream investment; these results supersede the preliminary actual results for 2020 that were reported in the 2020-21 Annual Report.

The COVID-19 pandemic had a major negative impact on investment in the industry compared to the pre-2020 period. In fact, the $16.7 billion investment in Alberta's mining, quarrying, and oil and gas extraction sector in 2020 was at the lowest level for the entire 2006-2021 period, with 2006 being the first year of the capital expenditure data series was reported by Statistics Canada.

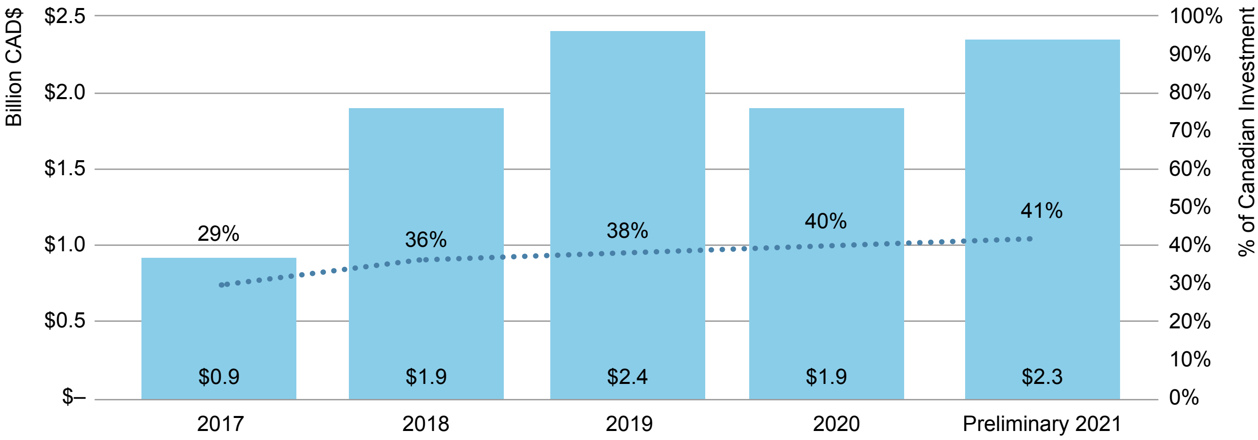
Investment in the mining, quarrying, and oil and gas extraction industry in Alberta has been estimated to increase to $18 billion in 2021, accounting for 51 per cent of the total Canadian investment in this industry.

It is significantly more difficult to examine the downstream energy industry than the upstream, as the downstream impacts are diffused throughout different industries, and, therefore, cannot be easily captured. Due to these limitations, downstream investment is focused on petroleum and coal product manufacturing, and chemical manufacturing. This allows for the coverage of petroleum refining and petrochemical manufacturing activity, among other downstream activities.

[4] Note: Totals may not add up due to rounding.

[5] Note: Further information on sources and methodology for this performance indicator can be found in the Performance Measure and Indicator Methodology section on page 86.

Capital Investment in Alberta Downstream Sector



Source: Statistics Canada

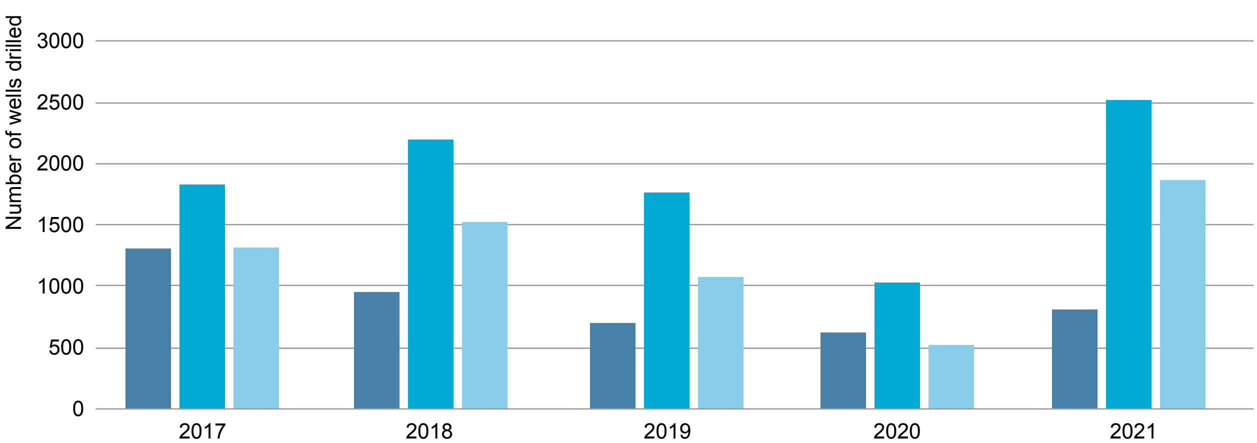
Overall, the trends that were observed, in Alberta, for the upstream energy industry investment over the 2017-2021 period did not consistently translate into similar trends for the downstream investment. The smaller downstream capital investment is much more susceptible to significant year-over-year swings due to major one-time investment decisions that may not actually reflect industry trends. For example, from 2018 to 2019, while investment in the mining, quarrying, and oil and gas extraction sector declined, investment in the downstream actually went up. Preliminary results for 2021 indicate a 21 per cent increase in Alberta downstream investment from the 2020 level to $2.3 billon. Overall, it is difficult to determine the trend for Alberta downstream investment, which consists of a range of industries with varying manufacturing end products.

Alberta has one of the most established petrochemical manufacturing centres in Canada, with room for potential growth in new and expanded facilities.

Alberta has a tremendous opportunity to capitalize on the growing global petrochemical sector, with our abundant natural gas reserves and a competitive, investor-friendly business environment. The Alberta Petrochemicals Incentive Program (APIP) is a key part of Alberta's Recovery Plan and the Natural Gas Vision and Strategy to turn the province into a top global producer of petrochemicals. It provides grants to companies to attract investment in new or expanded market-driven petrochemical facilities.

Drilling

Drilling Activity in Alberta



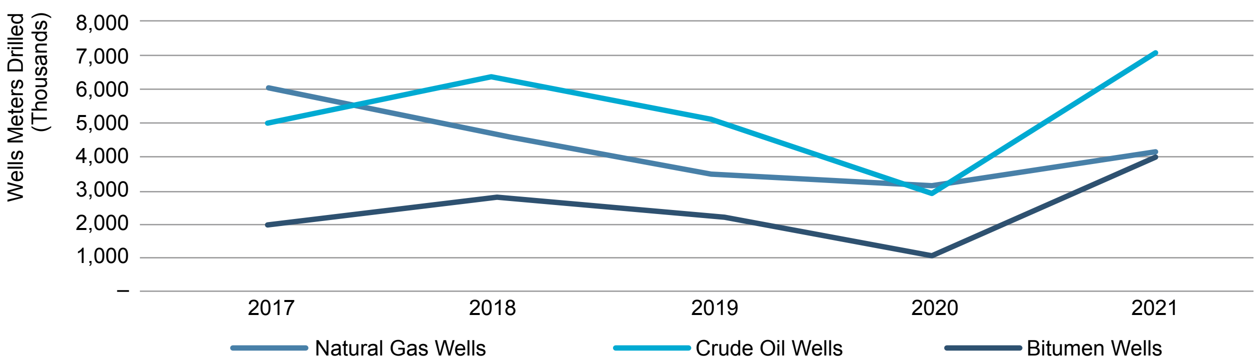
Source: Alberta Energy Regulator

Wells drilled include both development and exploratory wells. In 2018, the number of crude oil and bitumen wells increased relative to the 2017 level, while the number of natural gas wells declined. In 2019 and 2020, drilling activity declined for all three types of wells – crude oil, bitumen and natural gas wells, while in 2021 the trend reversed as drilling activity increased for all type of wells. The declines in 2019 and 2020 were primarily driven by the relatively low oil and gas price environment, which made it harder for companies to reach break-even points, and discouraged drilling activity. The COVID-19 pandemic exacerbated challenges facing the industry, and had a further negative impact on the overall drilling activity. However, as the demand for oil and gas in 2021 gradually recovered with eased global COVID-19 restrictions, the price environment improved. The drilling activity significantly recovered in the later months of 2021.

The total successful natural gas wells drilled increased by 34 per cent, from 598 in 2020 to 802 in 2021. Similarly, the total successful crude oil wells drilled increased by 148 per cent, from 1,014 in 2020 to 2,519 in 2021. Bitumen wells drilled also followed the upward trend, increasing by 271 per cent from 503 in 2020 to 1,866 in 2021.

Between 2017 and 2021, the highest total number of meters drilled in crude oil and bitumen wells occurred in 2021, while for natural gas it was in 2017.

Wells Meters Drilled

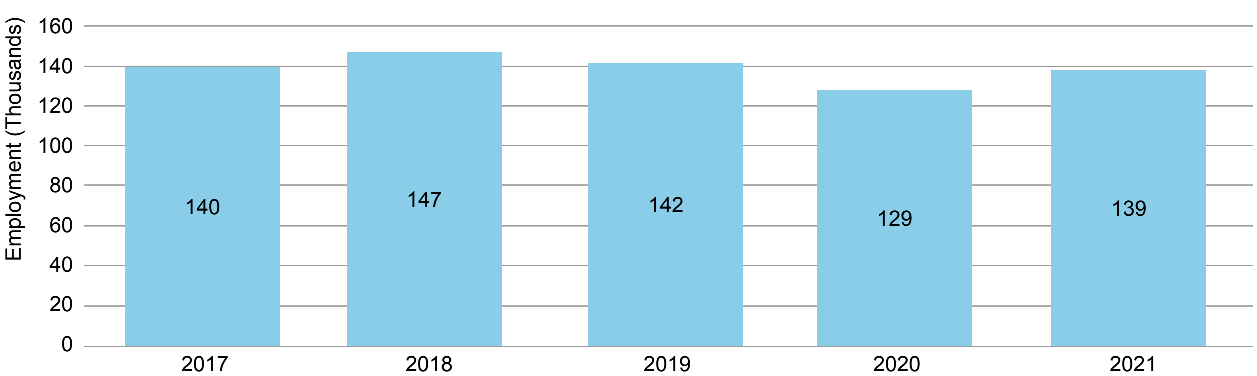


Sources: Alberta Energy Regulator

Employment

Employment in the mining, quarrying, and oil and gas extraction sector has been important to Alberta's economic performance. From 2017 to 2018, employment in the sector increased from 140,000 people to 147,000 people. In 2019, employment in the sector declined by about four per cent relative to its 2018 level to about 142,000 people. This trend continued in 2020, when employment in mining, quarrying and oil and gas extraction declined to 129,000 people due to impact of COVID-19 pandemic. However, in 2021, employment in the sector increased by eight per cent compared to 2020, to 139,000 people employed.

Employment in Mining, Quarrying, and Oil & Gas Extraction Sector



Source: Statistics Canada

Royalty Programs

The Government of Alberta owns 81 per cent of oil and gas resources in Alberta and collects royalties from companies when an oil or gas well, oil sands project, or mineral project is in production. On behalf of Albertans, the ministry reviews and maintains a competitive and effective royalty regime that attracts industry investment, which provides jobs, business opportunities, tax and royalty revenue, and numerous other benefits to the provincial economy. This work supports outcome one from the Ministry of Energy's 2021-24 Business Plan: Albertans benefit from investment in responsible energy and mineral development and access to global markets.

Royalty programs exist for a number of reasons, including:

- to provide appropriate royalty structure to attract investment in Alberta's energy sector in specific situations where the overall regime needs adjustment to achieve strategic investments;
- to encourage the development, use and commercialization of innovative technologies to produce resources; and
- to achieve certain strategic policy objectives such as increased value-added upgrading.

There are programs under the two royalty frameworks in Alberta: the Modernized Royalty Framework and the Alberta Royalty Framework.

The Modernized Royalty Framework took effect on January 1, 2017 and includes two strategic programs. Wells that were previously operating under the Alberta Royalty Framework and its programs are being grandfathered, either for a period of 10 years or until they reach certain expiring milestones already built into the programs.

To understand reporting for the royalty programs under the two Frameworks, it is important to consider the following points:

- The total royalty revenue for each royalty program is sourced from various royalty reporting systems for crude oil, natural gas and oil sands. Amendments by industry can be filed for up to three years from the production year. In addition, the total royalty revenue for each royalty program reflects the revenue from wells that are qualified for the respective royalty programs in a given year. It does not represent the net revenue from those wells as the royalty revenue on natural gas and gas products can be further reduced by eligible deductions, such as the Gas Cost Allowance.
- The royalty programs under the Alberta Royalty Framework are reported on a calendar year basis and reflect the amendments filed by industry each year.
- The royalty programs under the Modernized Royalty Framework are reported on a fiscal year basis to align with government reporting as a whole and reflect amendments filed by industry each year.
- In June 2019, government introduced the *Royalty Guarantee Act* to increase investor certainty that the royalty structure in place when a well is drilled will remain in place for at least 10 years.

Modernized Royalty Framework Royalty Programs

The Modernized Royalty Framework creates harmonized royalty formulas for crude oil, liquids and natural gas-based investment, and encourages industry to reduce costs. In 2017, Energy established two programs under the Modernized Royalty Framework: the Enhanced Hydrocarbon Recovery Program and the Emerging Resources Program.

Enhanced Hydrocarbon Recovery Program

This program came into effect on January 1, 2017 to promote incremental production through enhanced recovery methods intended for legacy fields, and replaces the Enhanced Oil Recovery Program that is being phased out. Enhanced recovery methods use the injection of fluids such as water, hydrocarbons, carbon dioxide, nitrogen, polymers or chemicals to recover additional hydrocarbon reserves.

The objectives of the Enhanced Hydrocarbon Recovery Program are to:

- provide appropriate royalty treatment for incremental hydrocarbon production to account for the higher costs associated with enhanced recovery methods,
- generate incremental hydrocarbon production through enhanced hydrocarbon development, and
- collect incremental royalty revenue for Alberta over the long-term.

During the 2020-21 fiscal year, the Enhanced Hydrocarbon Recovery Program received three applications in comparison to nine applications in the 2019-20 fiscal year. The decrease may be due to impacts from the COVID-19 pandemic, such as cost inflation due to supply chain disruptions and labor shortages increasing development costs for new projects. Since the program's inception in 2017, 35 applications were received from 22 companies, of which 17 were approved.

Enhanced recovery techniques are typically used in a phased approach in legacy fields where primary production has already occurred.

- Three applications for the secondary recovery phase of oil, which includes enhancing the recovery of oil from an oil pool by water flooding, gas cycling, gas flooding, polymer flooding or similar techniques, were approved during the 2020-21 fiscal year.
- Three applications for the tertiary recovery phase of oil, which includes enhancing the recovery of oil from an oil pool by miscible flooding, immiscible flooding, solvent flooding, chemical flooding or similar techniques, were approved during the 2020-21 fiscal year.

	2017-18	2018-19	2019-20	2020-21	Total
Number of Applications Received	11	12	9	3	35
Number of Different Companies Submitting Applications[6]	8	11	7	3	22
Number of Applications Approved	0	4	7	6	17
Number of Applications Denied	0	11	4	1	16
Number of Applications Withdrawn	0	1	0	1	2
Applications to be Processed at the end of 2020-21 Fiscal Year					0

Note: Application approval/denial/withdrawal are counted in the year a decision is made, not in the year of receipt of application.

The active enhanced recovery schemes in the program generated a total Crown production of 128,918 cubic metres of oil, and 181,071,700 cubic metres of gas in 2020-21. In comparison, active enhanced recovery schemes generated a total Crown production of 103,874 cubic meters of oil, and 202,207,200 cubic meters of gas in 2019-20, a year-over-year increase of 24.1 per cent for oil and a decrease of 10.5 per cent for gas. The increase in oil can be attributed to developed wells in the approved schemes starting hydrocarbon production, while the decrease in gas production can be attributed to a slowdown as a result of the COVID-19 pandemic.

[6] Note: Annual numbers of companies do not add up to the total as some companies submitted applications in more than one year.

Total Crown royalty volumes from the approved enhanced recovery schemes totaled 6,448 cubic metres of oil, 2,967 cubic metres of natural gas liquids and 14,569,900 cubic metres of gas, which translates to about $3.1 million in total royalty revenue in 2020-21, a decrease of 0.1 per cent from 2019-20.

	2017-18	2018-19	2019-20	2020-21
Total Crown Royalty Volumes – Oil (m^3)	1,071	2,698	5,195	6,448
Total Crown Royalty Volumes – NGL (m^3)	164*	1,395*	2,347	2,967
Total Crown Royalty Volumes – Gas (10^3m^3)	5,773*	12,407*	15,275	14,570
Total Crown Royalty Revenue ($)	817,788*	1,820,232*	3,114,633	3,112,904

*Previous year's data has been restated to show the Crown Royalty Volumes after the Royalty Rate is applied to align with control record methodology for determining oil data.

It is important to note that, without the program support, enhanced recovery schemes are generally not economic and unattractive to investors due to higher production costs and lower rates of return on investments. Without the program, the enhanced recovery schemes may not proceed to even produce the base production. In that regard, any royalty generated from those enhanced recovery schemes could be considered "incremental" to the Crown.

Emerging Resources Program

The Emerging Resources Program came into effect on January 1, 2017. This program encourages industry to develop new oil and gas resources in higher-risk and higher-cost areas that have large resource potential. The objectives of the Emerging Resources Program are to:

- provide appropriate royalty treatment for strategic emerging oil and gas resources that are high cost and high risk,
- promote innovation and industry experience to accelerate the development of these resources, and
- generate incremental royalty revenue for Albertans over the long-term.

During the 2020-21 fiscal year, the Emerging Resources Program received two applications. Since the program was launched, 23 applications have been received from 14 companies. Seven applications were approved, 14 applications were denied, one was withdrawn, and one was under review at the end of the 2020-21 fiscal year.

	2016-17	2017-18	2018-19	2019-20	2020-21	Total
Number of Applications Received	4	7	6	4	2	23
Number of Different Companies Submitting Applications[7]	4	6	5	4	1	14
Number of Applications Approved	0	1	3	3	0	7
Number of Applications Denied	0	4	1	5	4	14
Number of Applications Withdrawn	0	0	1	0	0	1
Applications to be Processed at the end of 2020-21 Fiscal Year						1

The cumulative number of potential new project wells participating in the program in 2020-21 fiscal year was 4,080. The number of new project wells did not increase in 2020-21 as no new applications were approved.

	2017-18	2018-19	2019-20	2020-21
Number of New Project Wells	766*	2,190*	1,124	0
Cumulative Number of Project Wells	766*	2,956*	4,080	4,080

*Previous year's data has been amended to match control record methodology.

[7] Note: Annual numbers of companies do not add up to the total as some companies submitted applications in more than one year.

Approved projects in the program generated a total Crown production of 305,744 cubic metres of oil, 22,179 cubic metres of condensate, and 1,921,373,600 cubic metres of gas in 2020-21. Increased production can be attributed to new project wells starting to produce.

Total Crown royalty volumes from Emerging Resources Program projects totaled 15,289 cubic metres of oil, 82,577 cubic metres of natural gas liquids, 1,109 cubic metres of condensate, and 83,788,100 cubic metres of gas. This translates to about $33.9 million in total royalty revenue in 2020-21 from approved Emerging Resource Program projects, a 99 per cent increase from 2019-20 – this increase can be attributed to a ramp up of production as the pandemic eased. This royalty revenue to the Crown may not have been generated without the program incentives.

	2017-18	2018-19	2019-20	2020-21
Total Crown Royalty Volumes – Oil (m^3)	9.5	7,387	7,246	15,289
Total Crown Royalty Volumes – NGL (m^3)	0	9,706*	37,126	82,577
Total Crown Royalty Volumes – Condensate (m^3)	1.7	1,888*	1,242	1,109
Total Crown Royalty Volumes – Gas (10^3m^3)	0.3	10,499*	34,120	83,788
Total Crown Royalty Revenue ($)	4,692	7,441,782*	17,068,405	33,911,792

*Previous year's data has been restated to show the Crown Royalty Volumes after the Royalty Rate is applied to align the methodology for determining oil data.

Alberta Royalty Framework Royalty Programs

The department has a number of royalty programs under the Alberta Royalty Framework that, as of 2017, are no longer accepting new entrants and will be phased out once their related regulation expires. The programs to be phased out include the Natural Gas Deep Drilling Program, Emerging Resources and Technologies Initiative, Incremental Ethane Extraction Program and the Enhanced Oil Recovery Program. The ministry will continue to monitor and report on the progress of these programs until they officially expire.

Natural Gas Deep Drilling Program (NGDDP)

The NGDDP has been making progress towards achieving its intended outcomes of encouraging new exploration and developing production by providing a royalty adjustment to wells with a vertical depth greater than 2,000 metres.

The royalty adjustment is based on the well's measured depth and is provided for a period of up to five years following the wells finished drilling date. The minimum royalty rate applied to natural gas and natural gas products is five per cent. For condensate, the minimum adjustment rate is zero.

The total residue gas production from eligible wells decreased by 51 per cent and liquids production decreased by 50 per cent from 2019 to 2020. Residue gas is the gas mixture left after separation and processing of natural gas liquids that are ready for delivery to the pipeline. The decrease in residue gas and liquids production is due to the termination of the program enrollment.

	2016	2017	2018	2019	2020
Total gas production from eligible wells	Residue Gas: 38,752,706 Liquids: 12,138,887	Residue Gas: 33,746,930 Liquids: 13,274,152	Residue Gas: 22,850,190 Liquids: 8,084,252	Residue Gas: 13,482,771 Liquids: 4,523,810	Residue Gas: 6,578,175 Liquids: 2,254,175
Total Royalty from NGDDP gas wells	$261 million	$307 million	$176 million	$86 million	$43 million

*Units of measurement for gas is 10^3m^3 and liquids is m^3.

The total royalty revenue for the NGDDP has decreased by 50 per cent from the 2019 result. In 2019, gas wells in the program contributed about $86 million in total royalty revenues. Total royalty revenue has decreased by $43 million in 2020. The decline in royalty revenue is consistent with the decline in production under the program. This is likely due to well production decline, wells reaching the NGDDP net cap, or 60 calendar months cap.

As of December 31, 2016, the NGDDP no longer accepts new wells into the program, which is being phased out.

The Emerging Resources and Technologies Initiative

Introduced in 2010, the purpose of the Emerging Resources and Technologies Initiative (ER&T) is to stimulate investment and encourage development of Alberta's unconventional resources through the deployment of new technologies. The initiative supports new exploration, development and production from Alberta's emerging resources in horizontal oil, shale gas, horizontal gas and coalbed methane. The ER&T was implemented to increase investors' ability to recover upfront investments by extending the maximum five per cent New Well Royalty Rate to acknowledge the higher costs and risks in the following four situations: horizontal oil, horizontal gas, shale gas and coalbed methane. No new wells have been accepted into the program since December 31, 2016.

Production under the program is measured for wells in each of the four situations. In shale gas wells, horizontal gas wells and horizontal oil wells, the production has decreased significantly. This is the result of expected production declines in existing wells. No new wells qualified for the program and production began to decline in existing wells.

The trend for coalbed methane production in the province is consistently downwards, which is supported by the AER ST98 report. The economics of coalbed methane wells continue to be challenging compared to other gas wells. Despite relatively low drilling costs, the supply cost for coalbed methane wells are among the highest. Coalbed methane wells produce mainly dry gas and have very low initial production rates. In addition, coalbed methane wells are typically drilled on a single-well basis and do not benefit from economies of scale associated with drilling multiple wells at one location. This is commonly used in tight and shale formations.

Overall production from horizontal oil and gas wells decreased in 2020 compared to 2019. Gas production under the horizontal gas new wells decreased to 0.04 billion cubic metres in 2020 from 0.08 billion cubic metres in 2019. Liquids production also saw a decrease to 0.03 million cubic metres in 2020 from 0.04 million cubic metres in 2019. This is due to termination of the program, since no new wells that spud from 2017 onwards are eligible for the program, and production from the existing wells decline as they mature. In addition, the pool of the ER&T wells has been shrinking as some of the remaining wells in the pool reach their production or volume cap, which also leads to production decreases.

Horizontal oil wells showed decreases of 77 per cent in oil production and 58.7 per cent in solution gas production in 2020, respectively from 2019. Oil production decreased to 0.05 million cubic metres in 2020 from 0.2 million cubic metres in 2019. Solution gas production decreased to 0.0006 billion cubic metres in 2020 from 0.0016 billion cubic metres in 2019. These decreases are due to termination of the program and high decline rate of the existing well production. Solution gas is the gas that is separated from crude oil or crude bitumen after recovery from a well event.

Production from shale gas wells include shale gas, liquids, oil and solution gas. Production from shale gas wells has decreased since no new wells qualified for the program in 2017. These decreases are due to termination of the program and high decline rate of the existing well production.

The total royalty revenue for ER&T in 2020 was approximately $4.2 million compared to the 2019 total royalty revenue of $18.7million. This accounts for 0.47 per cent of Alberta's total conventional Crown oil and gas revenues. Total revenue generated by wells in the program has decreased by 77.3 per cent compared to 2019. Due to the fact that no new wells were accepted into the program since 2016, and with prolonged low commodity prices, the total contribution of these wells to royalty revenue will likely be limited too.

The results for the ER&T initiative only reflect the wells that are qualified and receiving program benefits for a given year. As discussed previously, the ER&T lowers the royalty rate for qualified wells at the beginning of a well's production life for a limited time period (up to four years) or a maximum production amount. This is intended to reduce the return-on-investment time period for owners and to maintain Alberta's competitiveness. Most of these wells continue to produce and generate additional royalty revenue and other economic benefits for the Crown after they exit the program.

Incremental Ethane Extraction Program

Implemented in 2007, the Incremental Ethane Extraction Program (IEEP) provides $350 million in royalty credits to petrochemical companies that consume incremental ethane for the production of higher-value products, such as ethylene and its derivatives. The objective of the IEEP is to supply an additional 60,000 to 85,000 barrels per day of ethane for petrochemical companies to use as feedstock. The IEEP was being phased out, and ended on December 31, 2021.

The program allowed for a 60-month royalty credit eligibility period. In the 2020 calendar year, 13 of the 16 approved projects were in-service for the program. These 13 in-service projects are capable of providing up to 85,073 barrels per day of additional ethane or about 93 per cent of the total incremental ethane capacity approved by the minister for the IEEP. In the 2021-22 fiscal year, the department issued approximately $11 million in royalty credits to these projects for 2020 production year.

Approximately 80 per cent of the incremental ethane capacity was from natural gas sources with the remaining 20 per cent obtained from off-gas sources.

The supply and demand for ethane has continued to strengthen over the past few years and Alberta's petrochemical supply and demand balance is considered stable. Energy will continue to process royalty credits associated with in-service ethane extraction projects that are within their 60-month credit eligibility period.

Enhanced Oil Recovery Program

The Enhanced Oil Recovery Program was implemented in 2014 and has been making progress towards achieving its intended outcomes. This includes encouraging incremental crude oil production through enhanced oil recovery methods (EOR). This involves injecting approved materials other than water to increase oil recovery from a pool at existing developments. The program provides a maximum five per cent royalty rate for all oil produced from program-approved schemes for a defined period of up to 120 months. The program is intended to encourage increased investment in incremental oil production, realize incremental royalty volumes and ultimately increased royalty revenue.

No new applications were received in 2020 under this program, and no new schemes were approved into the program since the program is being phased out, and is scheduled to end on December 31, 2026.

Total Crown production from enhanced oil recovery in 2020 was 0.4 million cubic metres, which is a decrease of 96,337 cubic metres from the previous year. The Crown royalty volumes from active EOR schemes totaled to 39,121 cubic metres, which translates to approximately $12.6 million in total royalty revenue in 2020. The total royalty revenue decreased by over $14.6 million in 2020 from approximately $27.2 million reported in

2019. The decline in royalty revenue can be explained by a combination of substantially lower West Texas Intermediate (WTI) price and a significant drop in total Crown production from EOR. WTI was around US$39/bbl in 2020, compared to US$57/bbl in 2019. Crown production from EOR (and in turn, total Crown royalty volumes from EOR) dropped in 2020 due to economic shut-ins after the oil price crash, wells reaching maturity, and schemes terminating after reaching their benefit periods. Of this total royalty revenue, approximately $12.5 million was considered incremental royalty to the Crown that otherwise would not have been generated without the program. This is also a $14.6 million decrease from approximately $27.1 million in incremental royalty revenue reported in 2019.

	2017	2018	2019	2020
Total Crown production from EOR	717,828 m^3	642,834 m^3	502,289 m^3	405,962 m^3
Total Crown royalty volumes from EOR	103,927 m^3	103,891 m^3	69,605 m^3	39,121 m^3
Total Crown royalty revenue from EOR	$37.2 million	$44.6 million	$27.2 million	$12.6 million
Incremental Crown royalty revenue from EOR	$34.6 million	$41.6 million	$27.0 million	$12.5 million

It is important to note that, without the program support, EOR schemes are generally uneconomic and unattractive to investors due to higher production costs and lower rates of return on investments. Without the program, the EOR schemes may not proceed to even produce the base oil production. In that regard, any royalty generated from those EOR schemes could be considered “incremental” to the Crown.

Actions that Support the Priorities of the Government of Alberta Strategic Plan

Priority Two:
Protecting Livelihoods

Objective One:
Building on our province's strengths by growing key and emerging sectors, and ensuring greater pipeline access

- Energy continues to advocate for all projects that secure additional market access for oil and gas producers and help protect the value of Alberta's resources by intervening in all regulatory and legal proceedings where the province has standing, meeting with federal and state-level governments to advance projects in the U.S., participating in intergovernmental forums to build support for oil pipelines, and meeting with investors and attending industry events globally to promote Alberta's energy sector.
- Energy continued the implementation of the Natural Gas Vision and Strategy, including:
  - working with LNG project proponents, pipeline developers, and other governments to advance additional LNG projects on the west and east coasts of Canada;
  - capitalizing on opportunities in petrochemical manufacturing through the Alberta Petrochemical Incentive Program (APIP), with the first project to be approved, Inter Pipeline Heartland Petrochemical Complex, that will receive a grant of up to $408 million when it is operational – this will support 16,000 jobs during construction and 300 direct and 1,000 indirect jobs when in operation;
  - creating conditions for development of emerging opportunities like hydrogen through the release of the Hydrogen Roadmap in November 2021 as a path forward for Alberta to become a leader in the global clean hydrogen economy, while ensuring the province retains its place as an international supplier of responsible energy products; and
  - advancing work to help the province achieve more from plastic waste through pursuing a plastic circular economy.
- Energy continued to invest in job creation through environmental stewardship through the Site Rehabilitation Program – as of March 31, 2022, over $780.0 million in grant funding has been approved and is being allocated to 579 Alberta-based companies, creating over 3,700 jobs so far. Of the total approved applications:
  - $477.5 million has been allocated for 26,386 abandonment sites,
  - $20.6 million has been allocated for 13,781 Phase 1 environmental site assessments,
  - $67.7 million has been allocated for 4,402 Phase 2 environmental site assessments,
  - $56.8 million has been allocated for 981 remediation sites, and
  - $157.4 million has been allocated for 9,823 reclamation sites.
- In 2017, the Government of Alberta loaned the Orphan Well Association (OWA) $335 million interest-free to accelerate the reclamation of oil and gas well sites that no longer have a responsible owner. As of December 31, 2021, the Orphan Well Loan Program has spent the full $335 million, generating approximately 271 direct jobs, and reported the following results from its effort to address the growing inventory of orphaned sites:
  - a total of 3,512 wells abandoned,
  - 4,282 pipelines decommissioned, and
  - 2,303 sites reclaimed.

The work resulting from this loan is in addition to the OWA's ongoing work. As of April 2022, the OWA has repaid $91.6 million. The total amount loaned to OWA must be repaid by October 31, 2031.

Actions that Support the Priorities of the Government of Alberta Strategic Plan

Priority Two:
Protecting Livelihoods

Objective Two:
Reducing red tape

- Energy supported job creators by developing a regulatory system that encourages further private sector investment in oil and gas, and new investment in geothermal energy and mineral resource development – key achievements in 2021-22 included:
  - the release of the Minerals Strategy and Action Plan, "Renewing Alberta's Mineral Future," on November 4, 2021 to establish strategic directions and actions, towards making Alberta an attractive place for mineral exploration and development;
  - proclamation of the *Geothermal Resource Development Act* on December 8, 2021, which led to receipt of 33 tenure applications for exploration and development of Alberta's geothermal resources by March 31, 2022;
  - the release of the first Requests for Full Project Proposals (RFPP) for Carbon Capture, Utilization and Storage (CCUS) projects that would sequester emissions from the Industrial Heartland Region, which led to the selection of six proposals, announced on March 31, 2022, that will begin exploring how to safely develop Canada's first carbon storage hubs; and
  - in March 2022, released the second RFPP for CCUS projects that would sequester emissions for the rest of Alberta not covered by the first RFPP.
- Energy, including its agencies, have achieved the target of 20 per cent reduction in red tape for 2021-22, with a total reduction of 22 per cent, leading to nearly $1 billion in anticipated cost savings in the energy industry by 2022-23. This has all been achieved without compromising environmental protections or safety measures within the industry.
  - In 2021-22, Energy regularly engaged with stakeholders through industry panels and has made substantial progress in addressing industry concerns about regulatory burdens. Energy continues to solicit project ideas and prioritize initiatives to achieve red tape reduction goals and to address industry and public red tape reduction recommendations.

Discussion and Analysis of Results

COVID-19/Recovery Plan

Alberta's Recovery Plan is a plan to revitalize Alberta's economy and create new opportunities for every Albertan. It's a plan to build, to diversify, and to create jobs. The Government of Alberta launched the plan in June 2020 during a worldwide pandemic, global recession, and collapsing world oil prices. Today, Alberta's economy is on the rebound.

Alberta's energy sector will continue to play a key role in helping to meet the world's post-pandemic energy needs as it enables other emerging sectors to grow and succeed. Energy is setting an unprecedented path toward a new, innovative and diversified energy future while reducing emissions, supporting the development of ground-breaking technology and encouraging investment. Some key initiatives under Alberta's Recovery Plan that advanced these goals in 2021-22 include:

- continued to advocate for all projects that secure additional **market access** for oil and gas producers, and help protect the value of Alberta's resources;
- released a **hydrogen roadmap** that will chart Alberta's path to becoming a key part of the global clean hydrogen economy and supporting Alberta's place as an international supplier of responsible energy products;
- leveraged Alberta's natural geological advantages and furthered energy diversification by introducing a new **minerals strategy** with an investment of over $16 million in 2021-22;
- amended the *Mineral Resource Development Act* to clarify regulatory ownership for brine-hosted and hard-rock mineral exploration and development to enable responsible mineral development in Alberta;
- developed **geothermal related regulations** and regulation amendments to provide the Alberta Energy Regulator with the authority to regulate the safe, efficient and responsible development of Alberta's geothermal resources, investing over $1 million to advance this work in 2021-22;
- continued to invest in job creation through well, pipeline and site clean-up efforts in the oil and gas sector through the $1 billion commitment from the Government of Canada to the **Site Rehabilitation Program**, which also ensured Indigenous businesses and communities played a meaningful role in the post-pandemic energy strategy and become partners in prosperity;
- working with **utilities** and regulators to provide homes, farms and businesses with a $150 rebate over 3 months to cover the high costs this past winter, with a 2021-22 budget commitment of $296 million;
- beginning the work to provide **rebates to address high winter heating costs** from October 2022 to March 2023; and
- joined other provinces in supporting the development of **small modular nuclear reactors**.

Further information on these initiatives can be found in this report's discussion and analysis of results under Outcome One and Outcome Two.

Red Tape Reduction

Energy continues to remove regulatory barriers and reduce costs for Alberta's job creators, modernize our regulatory systems, and improve the delivery of government services while ensuring effective regulatory oversight over vital consumer, environmental, health and safety protections, and fiscal accountability. The Government of Alberta's ongoing commitment to reduce red tape by one third by 2023 is helping to make our province the most attractive destination for investment and job creation in North America, while strengthening Alberta's competitive advantage.

Energy, along with its agencies, have achieved the target of 20 per cent reduction in red tape for 2021-22, with a total reduction of 22 per cent, leading to nearly $1 billion in anticipated cost savings in the energy industry by 2022-23. This has all been achieved without compromising environmental protections or safety measures within the industry.

In 2021-22, Energy regularly engaged with stakeholders through industry panels and has made substantial progress in addressing industry concerns about regulatory burdens. Energy continues to solicit project ideas and prioritize initiatives to achieve red tape reduction goals and to address industry and public red tape reduction recommendations. Red tape reduction initiatives completed in 2021-22 include:

- Completed legislative amendments to help clarify geothermal legislative and regulatory requirements and enable responsible development of geothermal resources in Alberta.
- Amended the *Mineral Resource Development Act* to clarify regulatory ownership for brine-hosted and hard-rock mineral exploration and development to enable responsible mineral development in Alberta.
- Completed administrative efficiencies in petroleum and natural gas tenure agreement management to provide a means for industry to change the designated representative when agreements become stranded. This will allow lessees to more effectively manage agreements in which they have an interest.
- Amended the Natural Gas Billing Regulation to reduce the security deposit for competitive natural gas retailers to reduce red tape and barriers to entry into the natural gas retail market.
- The Alberta Energy Regulator (AER) completed the subsurface spacing and well testing requirements project, which included revised Directive 065 and Directive 040. The AER's Directive 040 sets out industry requirements for conducting pressure tests and fluid sampling on wells. Directive 065 details the AER's application process and requirements for operators looking to obtain approval to implement a strategy to produce oil or gas resources from an underground pool.
- The AER improved clarity for industry through the amendment of several manuals, which ultimately reduces administrative burden on oil and gas producers.
- The Alberta Petroleum Marketing Commission completed its streamlining auto payback of over deliveries. Completion of this project has resulted in time savings of one day per month for industry.
- The Alberta Utilities Commission (AUC) accomplished a 48.2 per-cent reduction in the regulatory requirements set out in its rules. Reducing regulatory burden has resulted in cost and time savings as well as other benefits for stakeholders, industry and the AUC.
- The AUC has overall decreased the length of time it takes to review applications by 39 per cent and found one-time savings of $4.1 million in 2021-22, which helped to reduce its administration fee.

Outcome One:

Albertans benefit from investment in responsible energy and mineral development and access to global markets.

What it means:

The ministry develops and manages policies and programs related to the province's royalty system to attract industry investment, provide jobs, business opportunities, tax revenue, and numerous other benefits to the provincial economy. It advocates for increased pipeline and takeaway capacity to access global markets to strengthen both provincial and national economies, while proactively communicating how the Government of Alberta produces energy with the highest environmental, labour, and human rights standards in the world. It seeks to influence challenges facing the natural gas sector, including those related to market access, price volatility, and intra- and interprovincial natural gas transportation and storage. The ministry advances a modern, market driven electricity system in Alberta that attracts investment and provides competitive rates for investors and Albertans. Ministry activities to reduce burdensome red tape and improve investor certainty in the energy sector will further these outcomes and help get Albertans back to work.

Key objectives to support this outcome included:

1.1 Improve market access for Alberta's energy resources and products to get Alberta's oil and gas to market and support Alberta's economic recovery.

1.2 Build on Alberta's strengths in responsible energy resource and mineral development, support industries and communities in economic recovery through innovation, diversification and job creation by:

- reinforcing Alberta's long-standing commitment to responsible energy and mineral resource development and communicating the province's energy industry performance;
- implementing the Natural Gas Strategy and Vision, including capitalizing on opportunities in liquefied natural gas and petrochemical manufacturing, and creating conditions for development of emerging opportunities like hydrogen and the plastics circular economy; and
- creating a regulatory environment that encourages the development of natural gas, geothermal, and minerals to leverage Alberta's natural geological advantages in these emerging areas.

1.3 Enhance Alberta's investment climate through measures to improve the province's standing with investors and support economic recovery, such as:

- continuing to invest in job creation through environmental stewardship by providing support to site rehabilitation and orphan wells;
- reducing red tape while streamlining legislative requirements and regulatory processes; and
- ensuring Alberta's safe, reliable electricity system provides competitive electricity rates for investors and Albertans to support the creation of jobs in the economy and attract investment as electricity costs are a factor in attracting and retaining investment in most sectors.

Key Objective 1.1

Improve market access for Alberta's energy resources and products to get Alberta's oil and gas to market and support Alberta's economic recovery.

Market Access

The Government of Alberta supports proposals for, and the development of, projects that can unlock new markets for Alberta's resources, including oil and gas and new mineral production. Every credible forecast of future world energy consumption sees oil and gas continuing to dominate the supply mix for the next several decades. The ministry continues to vigorously advocate on behalf of Albertans and Canadians whose livelihoods depend on it, and to engage with the Government of Alberta's counterparts in the federal government to market Canada's responsible and affordable energy.

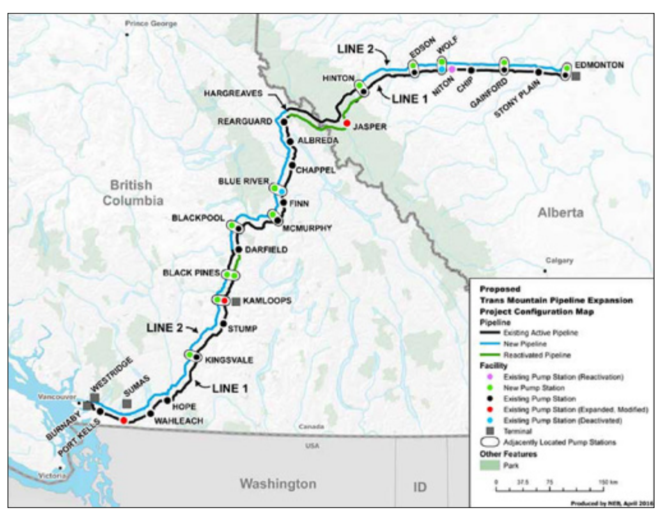
The Government of Alberta is advocating for all projects that secure additional market access for oil and gas producers, and help protect the value of Alberta's energy resources, through:

- intervening in all regulatory and legal proceedings where the province has standing;
- meeting with federal and state-level governments to advance projects in the U.S.;
- participating in intergovernmental forums to build support for oil pipelines, including the Energy Council, Council of State Governments, National Governors Association, Council of the Federation, and the Energy and Mines Ministers' Conference;
- meeting with investors and attending industry events globally to promote Alberta's energy sector, including CERAWeek;
- working collaboratively with other provinces in Canada to build national support for oil and gas pipelines; and
- contributing to the development of a provincial environmental, social and governance (ESG) approach aimed at strengthening and promoting Alberta's position as a responsible energy producer and attracting investment to the province's energy sector.

Market access activities in the department cost $1 million in 2021-22.

Trans Mountain Expansion Project

The Trans Mountain Expansion Project is the twinning of an existing 1,150-kilometre pipeline between Strathcona County, Alberta and Burnaby, British Columbia. Nominal system capacity will increase from approximately 300,000 barrels per day to 890,000 barrels per day. This pipeline will result in billions of dollars of economic prosperity for Canadians and create well-paying jobs throughout the country.



In February 2022, Trans Mountain Corporation announced, after completing a full review of the project schedule and cost estimates, mechanical completion of the project is anticipated to occur in the third quarter of 2023 and the project cost increased from $12.6 billion to $21.4 billion. This estimate includes all the costs of all known project enhancements, changes, delays and financing, including the substantial impact of the November 2021 floods in British Columbia.

As of March 2022, construction on the Trans Mountain Expansion Project is 50 per cent complete and the ministry continues to work with the federal government and Trans Mountain Corporation to ensure this critically important, federally approved project is completed. Approximately 11 per cent of the project workforce is Indigenous and the company has approximately 4,000 contracts with Indigenous businesses and partnerships worth over $2.7 billion. According to Trans Mountain Corporation, it has also entered into Mutual Benefit Agreements with 69 Indigenous Communities, worth more than $580 million – nearly $200 million more than the project's previous estimate.

Enbridge Line 3 Replacement Project

Originally built in the 1960s, Line 3 is an approximately 1,700-kilometre crude oil pipeline extending from Edmonton, Alberta to Superior, Wisconsin – it is an integral part of the Enbridge Mainline System. Enbridge recently replaced its Line 3 pipeline, restoring the line to its original capacity of 760,000 barrels per day, increasing Alberta's egress to the U.S. Midwest and other connecting markets for the first time since 2010. The project, brought into service in October 2021, replaced an aging pipeline with a new pipeline equipped with state-of-the-art technology and safety measures to protect the environment.

Enbridge Line 5

The Government of Alberta continued to support and advocate for Enbridge in legal cases against its Line 5. Line 5 is vital to the energy supply and economies of both the U.S. and Canada and has operated safely and reliably for decades. It is a critical source of propane and crude oil supply to Ontario, Quebec, Michigan and the Great Lakes Region. It also provides reliable energy jobs and economic benefits on both sides of the border. Shutting it down would lead to a serious disruption of the energy market and set a dangerous precedent for existing, safely-operating energy infrastructure.

On November 13, 2020, Enbridge was notified that the State of Michigan intended to revoke and terminate the 1953 easement, which allows the company to operate its dual pipelines in the Straits of Mackinac. The termination required Enbridge to cease operations of the dual pipelines in the Straits no later than May 2021 to allow for an "orderly transition that protects Michigan's energy needs." In response, Enbridge filed a federal complaint seeking an injunction to stop the State of Michigan from taking any steps to prevent the operation of Line 5. Enbridge also filed a petition to move the overall complaint to federal court. To date, Enbridge has refused to comply with Michigan's shut-down order, and there has been no further action from Michigan in response to the company's continued operation of the line beyond the arbitrary May 2021 deadline.

In alignment with Enbridge's objectives, and in support of ensuring this critical infrastructure continues to operate, the Government of Alberta continued to advocate as part of a "team Canada" approach on Line 5:

- In 2021 and early 2022, Alberta supported Canada's amicus briefs, submitted in May 2021 and February 2022 to the federal court in support of Enbridge's legal position.
- In October 2021, Canada formally invoked Article IX of the 1977 Transit Pipelines Treaty States, triggering bilateral negotiations over Enbridge's Line 5 with the United States government.
    - Approved on August 3, 1977, the Transit Pipelines Treaty was negotiated between Canada and the U.S. to ensure the uninterrupted transmission of hydrocarbons between the two nations. In order to protect this bilateral trade, the treaty broadly requires that neither Canada nor the U.S. implement measures that would "have the effect of impending, diverting, redirecting or interfering with the transmission of hydrocarbons in transit."

- In February 2022, Alberta also submitted a comment letter in support of Enbridge's plans to reroute a section of Line 5 in Wisconsin.

The legal challenges and Treaty discussions initiated by Canada are expected to take years to resolve. The broad precedent of a safely operated, fully regulated pipeline being pulled out of service has broad implications for existing and future energy projects.

Keystone XL

The Alberta portion of the Keystone XL pipeline project was 269 kilometres, starting in Flagstaff County, extending through the M.D. of Provost, Special Areas and Cypress County in southern Alberta. The pipeline would have continued into Saskatchewan and crossed the border through Montana, South Dakota and finally to Steele City, Nebraska. The Keystone XL Pipeline would have finalized the existing base Keystone Pipeline System. Approximately 145 kilometres of pipe was installed in Alberta and the Canada-U.S. border segment was completed in April 2020. The pipeline would have transported 830,000 barrels of oil per day to the U.S.

The Government of Alberta committed to provide $1.5 billion of equity investment in the project and a $6 billion loan guarantee in 2020 to accelerate construction on the pipeline. Alberta's investment in this project was linked to the province's long-term economic interests, such as higher oil prices, as well as increased volumes of oil sands crude production, projected to generate at least $30 billion in increased royalties over 20 years for Alberta taxpayers. The project was projected to put 17,000 Canadians to work and generate billions of dollars of employment income for Canadian and U.S. workers at a time when these increases would have helped with economic recovery.

After the 2020 U.S. election outcome, TC Energy Corporation and the Government of Alberta continued to work to demonstrate the importance of Keystone XL to North American energy security. However, the executive order revoking the Presidential Permit for Keystone XL was signed by President Joe Biden in January 2021, resulting in TC Energy suspending its activity on the pipeline.

On June 9, 2021, Alberta Petroleum Marketing Commission (APMC) and TC Energy reached an agreement for an orderly exit from the Keystone XL project and partnership. Final negotiated costs to the government remain materially within $1.3 billion, comprised of $384 million in equity investment and $941 million in loan guarantees. APMC and TC Energy continue to explore all options to recoup the government's investment in the project including proceeds from the sale of assets and legal recourse options.

In February 2022, the Government of Alberta, through the APMC, initiated a legacy North American Free Trade Agreement claim under the Canada-United States-Mexico Agreement over the cancellation of the presidential permit for the Keystone XL pipeline border crossing. It was determined that a legacy claim was the best avenue to recover the government's investment in the Keystone XL project. The claim will seek to recover no less than $1.3 billion of the government's investment.

As part of the Government of Alberta's ongoing efforts to protect the province's investment in the Keystone XL project, the government submitted an amicus brief in the Texas lawsuit challenging President Biden's cancellation of Keystone XL. In addition, following an analysis of divestment estimates regarding KXL assets, an agreement was reached to provide APMC, on behalf of the Government of Alberta, proceeds from the disposition of certain KXL assets. To date, APMC has received approximately CAD$38 million in proceeds from the sale of project assets, which were fair valued at March 31, 2022 to be CAD$82 million.

Federal Advocacy

Energy advocates for Alberta's market interests through participation in industry committees and CER proceedings regarding federally regulated energy infrastructure and service applications. This work supports Energy's objectives to strengthen market access for Alberta's natural resources. In 2021-22 this included:

- advocating for Alberta's position on the Enbridge Mainline Contracting application before the CER,
- supporting Trans Mountain positions in Canada Energy Regulator (CER) considerations for Notice of Constitutional Questions filed by the City of Burnaby, and
- intervening in CER processes to support the ongoing expansion on the NGTL system through various applications.

Public Inquiry Report

On July 4, 2019, the Government of Alberta launched a public inquiry, under the *Public Inquiries Act*, into the existence of anti-Alberta energy campaigns and the foreign sources of funds behind it. The public inquiry final report was delivered to government on July 30, 2021, and was publicly released on October 21, 2021. The report identified foreign funding flowing into Canada, which has the potential to influence matters of public interest to Albertans and Canadians.

According to the report, total foreign funding of environmental initiatives was $1.28 billion between 2003 and 2019. This funding directly impacted the lives and livelihoods of Albertans.

The Government of Alberta has completed or started work on a number of wide-ranging initiatives in alignment with the commissioner's recommendations and will continue to examine opportunities to further its commitment to protecting the best interests of Albertans and supporting the province's energy sector. Over the past two-plus years, government has already completed or commenced work on a number of initiatives – spanning many different departments – that are in alignment with the commissioner's recommendations.

The government remains committed to protecting the best interests of Albertans and supporting the province's energy sector.

U.S. Engagement

Alberta is recognized as an essential part of the reliable, affordable and integrated North American energy system. As a result, it is imperative for sustained and coordinated engagement to build mutually beneficial relationships that will help reinforce the importance of Alberta's energy products to the system and Alberta's strong environmental, social and governance record. Elected officials in the U.S. understand the importance of Alberta's energy resources to the North American energy system. Energy worked closely with the Alberta Washington Office to coordinate U.S. engagement related to energy files.

Due to pandemic-related travel restrictions, meetings and conferences were mostly conducted virtually for the 2021-22 fiscal year. The Minister of Energy's expertise in the North American energy system was recognized broadly and this led to key meetings and speaking opportunities that were unprecedented. Minister Savage met with energy officials from governments, companies and industry associations across the globe, including:

- attending the World Petroleum Congress and Energy Council in December 2021, and
- headlining speaking role at CERAWeek 2022.

In all her engagements, Minister Savage shared Alberta's progress on key energy files, including CCUS, methane emission reduction, well reclamation, critical minerals, natural gas, and hydrogen.

Building an Interprovincial Coalition of Provinces

Energy continued to work with provinces, territories, and the federal government through formal forums and ongoing bilateral relationships to make Alberta's energy industry a top priority. Through interprovincial engagements – including work related to methane equivalency and small modular reactors – the government is committed to engaging with other provinces on mutual priorities.

The government continues to explore opportunities to strengthen the provincial government's relationships with Canada's energy ministers.

Crude by Rail

In May 2019, the Alberta Petroleum Marketing Commission was tasked with divesting nineteen crude-by-rail contracts from the government to the private sector. As of March 31, 2022, APMC has assigned or terminated 100 per cent of the value of the original crude-by-rail contracts and fully divested the program. The estimated cost of continuing to operate the program was between $2.3 and $2.7 billion. The total cost of divestment was $2.2 billion, which included $866 million in 2021-22.

The start of the COVID-19 pandemic and an OPEC price war in 2020 brought a crash in commodity prices resulting in delays in assigning the crude by rail contracts.

The contracts, entered into by the previous government, covered all aspects of the crude-by-rail program, including rail cars, buffer cars, inspection and delivery fees, railway tolls, terminals, storage tanks, loading at terminals, interconnection, various taxes, customs, cross-border fees, and logistics. The crude-by-rail program was intended to ship an additional 120,000 barrels of oil per day from the province. It was developed to ease market access issues associated with rising production volumes and a lack of pipeline takeaway capacity. When the program was setup in 2018-19, Alberta was producing significantly more crude oil and bitumen than it could export by pipeline or rail. The lack of export capacity resulted in storage build-up and significant price discounts for Alberta's crude oil and negatively impacted the price-sensitive government royalties and industry activity. Rail is a higher-cost option that is not accessible to all producers: large producers use rail when price discounts are significant and/or to fill long-term commitments, while small producers cannot finance their own rail program and often do not have contracts to ship on pipelines.

Curtailment

In January 2019, the Government of Alberta implemented a policy that limited crude oil production to match the province's takeaway capacity. The policy was to remain in place for one year until additional takeaway capacity in the form of additional pipelines and rail became available. This was done to protect the value of the province's oil by helping prevent Canadian crude from selling at large discounts. Throughout 2019, Energy continued to refine the Curtailment Rules to provide industry with options and enhance production limits, including:

- The number of operators affected was reduced by almost half by increasing the production exemption from 10,000 barrels per day to 20,000 barrels per day.
- The use of special production allowances permitted curtailed operators to increase production above their curtailment limit on the condition that the additional volumes were shipped out of Alberta by rail.
- Effective November 2019 all new conventional oil wells spud on or after November 8, 2019 were exempt from curtailment.

Due to continuing pipeline delays, the policy was extended by an additional year until December 31, 2020.

In October 2020, due to continuing pipeline delays, the policy was further extended, as an insurance policy, until December 31, 2021. Through 2021, the Government of Alberta closely monitored production storage inventories, pipeline capacity, and rail shipments as well as global demand to ensure that production and take away capacity did not come out of balance. Government intended only to put production limits back in place if there was a significant risk of inventories reaching maximum capacity. During 2021, storage and other indicators did not reach these significant limits and thus production limits were not implemented. As a result of Enbridge's Line 3 being operational and the expected completion of the Trans Mountain Expansion Project in 2023, the decision was made in October 2021 to allow the Curtailment Rules to expire on December 31, 2021.

The Curtailment policy, created under highly volatile market conditions, was an unprecedented event for government. Government's intervention in the market was not viewed as ideal; however, it was accepted as necessary. The policy was intended to be a short-term measure until additional take away capacity was available. As the market is now working as it should, it has met its required objective and is no longer needed.

NGTL Pipelines

Alberta continued to advocate for increased market access to protect the value of Alberta's energy exports. The NOVA Gas Transmission Ltd. (NGTL) system transports natural gas produced in the Western Canadian Sedimentary Basin to markets in both Canada and the U.S. The NGTL system is federally regulated by the Canadian Energy Regulator (CER) and is a wholly owned subsidiary of TC Energy. According to the CER, the NGTL delivered over 4.2 trillion cubic feet of natural gas in 2020. This equates to 11.6 billion cubic feet per day. A little over half of transported natural gas volumes were destined for markets in eastern Canada/northeastern U.S., mid-western U.S. and the Pacific Northwest/California markets. The remaining natural gas was delivered to customers in Alberta and British Columbia.

Since 2020, NOVA Gas Transmission Ltd. has received several expansion approvals:

- Governor in Council (GIC) approval granted in October 2020 for the 2021 NGTL System Expansion Project, which includes the construction of 344 kilometres (km) of 48-inch diameter pipe and three 30-megawatt (MW) compressor station unit additions.
- NGTL continues to advance the Project's construction but highlights delays on account of COVID-19 restrictions, weather conditions and challenges attracting and retaining crews. TC advises the Project will not be fully completed until the first quarter of 2023.
- North Corridor Expansion Project GIC approval granted in April 2021, which includes the construction of 56 km of 48 inch diameter, 25 km of 36 inch pipeline and a new 30-megawatt compressor station unit addition. Pipeline construction are ongoing with full completion expected in the fall of 2022 or first quarter of 2023. It is anticipated that construction will be complete and project components placed into service by second quarter of 2023.
- Edson Mainline Expansion Project GIC approval granted June 2021, which includes nearly 85 km of 48 inch diameter pipeline. Construction activities commenced in third quarter 2021 and it is anticipated that construction will be complete and the project placed into service in fourth quarter 2022.

Another expansion project, the West Path Delivery 2023 project, which would include the construction and operation of approximately 40 km of 48 inch diameter pipe in Alberta, is being reviewed by the Canadian Energy Regulator and a decision is pending.

Key Objective 1.2

Build on Alberta's strengths in responsible energy resource and mineral development, support industries and communities in economic recovery through innovation, diversification and job creation by:

- reinforcing Alberta's long-standing commitment to responsible energy and mineral resource development and communicating the province's energy industry performance;
- implementing the Natural Gas Strategy and Vision, including capitalizing on opportunities in liquefied natural gas and petrochemical manufacturing, and creating conditions for development of emerging opportunities like hydrogen and the plastics circular economy; and
- creating a regulatory environment that encourages the development of natural gas, geothermal, and minerals to leverage Alberta's natural geological advantages in these emerging areas.

Environmental, Social and Governance Performance (ESG)

The Government of Alberta is prioritizing the development of a provincial ESG approach aimed at strengthening and promoting Alberta's position as a responsible energy producer and attracting investment into the province. In March 2021, the Premier announced the creation of a secretariat within Executive Council to coordinate and integrate ESG-related work across the Government of Alberta. Energy continues to provide input to and coordinate with the ESG Secretariat to build capacity and knowledge on ESG-related issues in the energy sector. Through a jurisdictional ESG lens, Alberta has the opportunity to show investors how government, industry, institutions and Indigenous communities are working together to lead the world in ESG performance.

ESG criteria are increasingly being used by investors to screen potential investment opportunities, highlight corporate behavior, and identify material risk traditionally left undisclosed. ESG criteria are non-financial performance measures used to assess the sustainability and societal impact of a particular investment. Over the past 10 years, ESG investment has grown from USD$13.3 trillion to USD$31.7 trillion – a 238 per cent increase – which is now growing at an accelerated rate. The goals of the government's ESG-related activities are to:

- showcase Alberta's ESG success with key audiences, Canadians and investors, and provide accurate information related to Alberta's ESG performance to support investment in Alberta;
- combat misinformation that is targeted to paint the industry in a bad light; and
- clearly articulate the role for Alberta's industry, particularly its energy industry, within a carbon-constrained world.

Canada – led by Alberta – demonstrates strong leadership in ESG performance among energy producing nations. As a result of technological innovation, Alberta's oil sands producers have reduced emissions per barrel by 36 per cent since 2000 (22 per cent over the past decade), with leading producers on track for another 16-to-23 per cent reduction over the next 10 years. As a result, the carbon intensity of many oil sands crudes fall within the range of other commonly traded crude oils. Over 95 per cent of major oil sands producers in Canada, largely in Alberta, have committed to net-zero by 2050 through further emissions intensity reduction, mitigation, and sequestration engineering solutions.

Natural Gas Investment Attraction

Alberta's Investment and Growth Strategy supports recovery efforts to drive new investments into Energy's key industries and emerging sectors that will ultimately lead to more jobs for Albertans. The Natural Gas Strategic Engagement Plan is aligned with the broader Government of Alberta investment strategies by diversifying key industries, including petrochemicals, and building new investment opportunities for clean hydrogen, liquefied natural gas and the plastics circular economy.

Natural gas investment attraction activities include targeted investor and stakeholder discussions to facilitate investments, collaborations with Global Affairs Canada and Canadian Trade Commissioner Service on investment inquiries, high-level participation at strategic events, and media engagements to promote Alberta's natural gas investment opportunities. Alberta has a tremendous opportunity to capitalize on the growing global petrochemical sector and diversify the province's economy, with Alberta's abundant natural gas reserves and Energy's competitive, investor-friendly business environment. Sitting on top of the Western Canadian Sedimentary Basin, Alberta has potential reserves of 223 trillion cubic feet, representing a multi-generational supply of gas deposits.

Targeted investment discussions were held with Japan, Korea, Malaysia, Taiwan, Netherlands, Switzerland, U.S., and United Kingdom, among others. Associate Minister Nally met with executives at various natural gas related events that were attended by domestic and international stakeholders. In addition, Alberta received recognition from the World Hydrogen Council on Alberta's experience and progress on hydrogen deployments at the 2021 World Hydrogen Summit. In 2021, Energy attended 13 natural gas related events and a number of bilateral engagements with key stakeholders.

Did you know?

Canadian natural gas has the ability to supplant coal use in other parts of the world, and is produced with consistent reductions in emissions intensity?

https://www.canadianenergycentre.ca/cleaner-canadian-natural-gas-overall-emissions-intensity-down-by-nearly-22-since-2011/

Alberta Petrochemical Incentive Program (APIP)

The APIP is a grant based program launched on October 30, 2020 with the intent of propelling Alberta to become a global leader in petrochemical production, and bringing long-term investments and thousands of jobs to the province. In 2021-22 there has been significant interest in the program, including the announcement of multi-billion dollar investments as a direct result of APIP and Alberta's competitive advantage in this sector. Projects that have submitted initial applications so far represent billions in total investment if they are all built and tens of thousands of construction and permanent jobs.

The Inter Pipeline Heartland Petrochemical Complex is the first project to be approved under APIP, and will receive a grant of up to $408 million when it is operational. The complex is a $4.3 billion facility in Strathcona County that will come online in late 2022, converting Alberta propane into polypropylene, a recyclable plastic. The construction of this facility is estimated to have generated 16,000 jobs with the support of over 150 Alberta-based businesses, with Alberta businesses receiving 75 per cent of the project spend. When operational, this facility would support 300 direct and 1,000 indirect jobs. Inter Pipeline estimates it contributed $200 million in direct provincial revenue during construction and will contribute $50 million per year once operational.

Alberta's Industrial Heartland Association estimates that there is an opportunity to attract more investments like Inter Pipeline's and grow the sector by more than $30 billion by 2030, resulting in tens of thousands of jobs for Albertans. For more information on the program, visit: https://www.alberta.ca/alberta-petrochemicals-incentive-program.aspx

Liquefied Natural Gas (LNG)

Energy continues to work with industry and government partners to explore options to advance LNG projects that utilize Alberta natural gas as feedstock. LNG was identified as one of the priority markets in Alberta's 2020 Natural Gas Vision and Strategy, and represents a significant opportunity for western Canadian natural gas sector growth and diversification. LNG is critical to gain access to global markets for western Canadian natural gas. Energy's goal is for Alberta's natural gas to have access to Asian and European markets through two to three additional mega LNG projects by 2030.

Alberta collaborated with British Columbia, Nova Scotia, the federal government, and foreign governments to preserve and attract new investment to Canada's LNG sector. This includes regular information sharing, joint meetings with targeted investors, and supporting Canada's ability to attract investments to the LNG sector. Energy is also working with LNG project proponents, pipeline developers, and other governments to advance additional LNG projects on the west and east coasts of Canada.

Did you know?

Canada is among the top five natural gas producers in the world, and about two-thirds of Canada's production comes from Alberta.

The natural gas industry directly employs tens of thousands of Albertans and many more indirectly working in related sectors such as petrochemicals.

Supplying Canadian natural gas to replace coal-fired electricity production, especially in growing Asian markets, can help reduce global greenhouse gas emissions by millions of tonnes per year.

Energy security is getting increased global attention following Russia's war with Ukraine and the resulting impact on European energy markets - Europe's LNG contracts have increased drastically to compensate for the reduction in natural gas from Russia, triggering global LNG buying competitions and LNG price hikes. Responsibly-sourced, Western-Canadian natural gas and LNG has the opportunity to be part of the solution for Europe.

Hydrogen Roadmap

Alberta is already the largest hydrogen producer in Canada, and it has the resources and expertise needed to become a major global supplier of this emerging resource. The Hydrogen Roadmap, released November 2021, is the path forward for Alberta to be leader in the global clean hydrogen economy, while ensuring the province retains its place as an international supplier of responsible energy products. The Hydrogen Roadmap will help further reduce carbon emissions and strengthen Alberta's ongoing leadership in environmental, social and governance measures. Alberta is already moving ahead with immediate actions identified in the Hydrogen Roadmap to grow domestic markets and develop understanding of opportunities to grow Alberta's hydrogen exports. Immediately after the Hydrogen Roadmap release, Energy initiated work to inform development of regulatory and legislative changes to enable hydrogen blending into natural gas distribution systems. This involved targeted stakeholder engagement. As a next step in this process, on March 23, the Minister of Energy directed the Alberta Utilities Commission to undertake an inquiry on hydrogen blending, with a final report submitted by June 30, 2022.

Energy has also initiated foundational work to understand Alberta's hydrogen export market opportunities, examine ways to deploy hydrogen into the provincial transportation market, and develop carbon intensity thresholds for clean hydrogen. Energy staff are also participating in numerous working groups led by the Government of Canada to implement the federal Hydrogen Strategy.

Targets of the Hydrogen Roadmap include:

- clean hydrogen integrated on a large scale into provincial energy systems by 2030;
- exports of clean hydrogen and hydrogen-derived products to jurisdictions across Canada, North America and globally in place by 2030;
- over $30 billion in new capital investment allocated to clean hydrogen production;
- tens of thousands of jobs and billions of economic activity during the construction phase; thousands of jobs and hundreds of millions of economic activity during the project operations phase; and
- greenhouse gas reductions of 14 megatonnes.

A number of major international and domestic companies announced plans to develop hydrogen projects in Alberta, including Air Products, Itochu and Petronas, Mitsubishi, Shell, ATCO and Suncor. Together these projects may represent billions of dollars of investment and show significant international interest in Alberta's hydrogen opportunities.

Did you know?

Alberta is already the largest hydrogen producer in Canada with significant volumes of hydrogen supporting bitumen upgrading and chemical manufacturing. Alberta has a multi-decade experience and expertise producing and handling hydrogen at scale.

Hydrogen is the most abundant molecule in the universe and can be used to produce energy for many different applications, such as in transportation, electricity generation, industrial processes, and even blended with natural gas to heat homes and businesses.

Hydrogen emits no carbon dioxide when it is burned – the only by-product is water.

Hydrogen can be produced from a number of sources, including water and natural gas.

Emissions Reduction Alberta and Alberta Innovates have provided over $60 million in funding to 14 hydrogen projects. These projects include hydrogen powered buses, trucks, and locomotives, new hydrogen production technologies, hydrogen blending into utility markets, and development of hydrogen hubs.

Clean Hydrogen Centre of Excellence

The Clean Hydrogen Centre of Excellence will be established in spring 2022 and fulfills the Government of Alberta's commitment to support hydrogen technology and innovation across the provincial economy. The Centre's primary purpose is to identify promising hydrogen technologies and accelerate its development so that Alberta companies can head towards commercialization faster. This sends an important signal to investors that Alberta is prepared to move quickly into this new value chain, close innovation gaps, and accelerate technology commercialization.

Work was carried out throughout 2021-22 to set up the Centre of Excellence, including establishing its operations and capital budget as well as setting up its governance structure. This involved close collaboration between: Energy; Jobs, Economy, and Innovation; Advanced Education; and Alberta Innovates.

The Centre of Excellence will be funded by the Technology Innovation and Emissions Reduction (TIER) program, receiving $50 million spread out over the next four years. Investments and grants from industry and other levels of government are expected to amount to an additional $150 million. The Centre of Excellence will be operated by Alberta Innovates, which has a proven track record of accelerating Alberta-made technologies, and will tie it into Alberta's existing innovation support systems.

Plastic Circular Economy

A circular economy is restorative and regenerative by design, with materials flowing in a closed-loop system, rather than used once and discarded. In the case of plastic, the value of plastics in the economy is retained, without leakage into the natural environment. The plastic circular economy involves rethinking the way plastics are made, used, reused, and recycled. Mechanical and chemical recycling both play an important role in determining how much plastic material can re-enter the market. Through a systemic approach, post consumer plastics are not waste, but rather become a commodity to be collected and used again.

Plastics circular economy is one of five pathways identified in Alberta's Natural Gas Vision and Strategy that has great potential for growth. Alberta's goal is to be established as the Western North America centre of excellence for plastics diversion and recycling by 2030. This goal will be achieved by advancing plastics recycling research to complement province-wide recycling and diversion systems. Through the Plastics Alliance of Alberta (PAA), the Government of Alberta is collaborating with industry, academia, and key organizations to help transform and innovate Alberta's plastics sector by creating a plastics circular economy within the province.

Did you know?

Plastic is not the problem. Waste is.

Alberta is home to Canada's largest petrochemicals industry and as global demand for plastics continues to grow, initiatives to support responsible production will become even more important in the future.

Plastics keep food safe and fresh and are used in vehicle air bags, bike helmets, eyeglasses, cell phones, computers, and perhaps most importantly right now: personal protective equipment and medical supplies.

Possible future economic benefits from increased recycling in Alberta are CAD$1.4 billion and approximately 13,300 jobs (direct, induced and indirect).

In 2021-22, Energy continued to work with the PAA, to help the province achieve more from plastic waste through pursuing a circular economy. The PAA provided policy recommendations for government to advance the plastics circular economy – these recommendations support identifying challenges and potential solutions to shape government policy and strategy. The PAA recommendations focused on four areas: advancing extended producer responsibility, regulatory improvements to encourage plastic circular economy activities, develop recycled content policy and government funding mechanisms for the value chain. Further work is being undertaken to understand the implications of these recommendations and how Alberta can continue to work with stakeholders across the plastics value chain to prioritize the transition to a circular economy. Energy is also supporting Environment and Parks as they develop Alberta's Extended Producer Responsibility regulation. Energy has been actively working to form partnerships and shepherd investments in advancing the plastics circular economy in Alberta. Partnerships will stimulate ongoing growth opportunities and accelerate the commercial deployment of technologies, as well as infrastructure build-out in industrial areas.

Alberta's existing recycling economy creates about 7,500 direct and indirect jobs. Increasing recycling in Alberta has the potential to create an additional 13,300 jobs and $1.4 billion dollars in economic activity. Alberta is home to Canada's largest petrochemicals industry, and as global demand for plastics continues to grow, initiatives to support responsible production will become even more important in the future. Alberta has ambitions to become a leading hub, not just in plastics recycling, but in petrochemical production, and government sees the two industries growing in tandem.

Minerals Strategy and Action Plan

Worldwide demand for metals and critical minerals is rising due to technological advancements, growing populations, and national security goals. Alberta is well positioned to leverage its vast expertise in resource development to advance a competitive and sustainable minerals sector. Alberta's established and experienced energy sector provides many strategic advantages that can help advance the province's minerals sector.

The Government of Alberta released its Minerals Strategy and Action Plan, namely "Renewing Alberta's Mineral Future" on November 4, 2021 to establish strategic directions and actions toward making Alberta an attractive place for mineral exploration and development. The strategy will help capitalize on Alberta's potential to become a preferred international producer and supplier of minerals and mineral products such as lithium, uranium, vanadium, rare earth elements, potash, and diamonds. The full strategy and action plan can be viewed at: https://www.alberta.ca/minerals-strategy-and-action-plan.aspx

As a first step towards implementation of the Minerals Strategy and Action Plan, Alberta passed Bill 82: the *Mineral Resource Development Act* in December 2021 to enable a robust and competitive regulatory environment for mineral development in the province. The act helps ensure the responsible management and development of the province's mineral resources and establishes Alberta Energy Regulator (AER) as the full-lifecycle regulator for Alberta's mineral resources – from exploration through reclamation – providing certainty for the industry, helping position the province as a preferred mineral producer and spurring growth in the sector. This one-window approach provides regulatory clarity for industry, while protecting the best interests of Albertans by ensuring the safe, orderly, efficient and responsible development of the province's mineral resources. The act helps set out regulatory processes and requirements, and provides a clear regulatory roadmap to reduce investors' risk and enhance regulatory certainty and clarity.

Key Actions

The Minerals Strategy and Action Plan focused on key actions including:

- improving public access to quality data about mineral occurrences in Alberta,
- having a streamlined regulatory environment in place that assures environmentally responsible development,
- enhancing opportunities for Indigenous Peoples,
- developing public awareness and a skilled workforce, and
- promoting innovation and attracting investment.

To foster a smooth transition, the Government of Alberta is pursuing a phased approach for implementation: the first phase, which is underway, focuses on establishing a regulatory framework for brine-hosted mineral development, and the second phase will enhance the regulatory framework for hard-rock mineral development.

Throughout 2020 and 2021, Energy hosted a series of stakeholder and Indigenous engagement sessions to inform the development of the Minerals Strategy and Action Plan as well as its implementation of Bill 82. In April 2020, the Government of Alberta established the Mineral Advisory Council to offer strategic advice, guidance, and recommendations throughout the stakeholder engagement process. The Mineral Advisory Council consists of members representing key stakeholders in the minerals industry across Canada and internationally, or members who have senior or executive leadership experience in geology, resource development, Indigenous relations, regulatory and environmental affairs, and investor and industry perspectives.

Engagement sessions included:

- Phase 1: an online survey on the minerals strategy, mineral regulatory regimes and tenure - October 2020;
- Phase 2: roundtable discussions on mineral regulatory regimes and tenure - January 2021;
- Phase 3: roundtable discussions on hard rock mineral regulatory regime and the *Mineral Resource Development Act* legislative engagement - August and November 2021 respectively; and
- Phase 4: a virtual roundtable on mineral tenure modernization - March 2022.

Alberta has strong partnerships with Indigenous communities that will help achieve the economic and social benefits from responsible mineral development. A guiding principle of the mineral strategy and action plan, Renewing Alberta's Mineral Future, is to advance opportunities for Indigenous Peoples. This includes: ensuring that traditional Indigenous land uses are recognized regarding mineral development; enhancing involvement of Indigenous entrepreneurs and business in mineral exploration and development; and understanding opportunities, interests and potential concerns of Indigenous Peoples. Indigenous Peoples were engaged throughout the finalization of the Minerals Strategy and Action Plan, as well as the development of mineral policies and regulations, including the work around Bill 82 and Tenure Modernization. The engagement will continue in the coming years to inform the implementation of the Minerals Strategy and any policy and regulatory development.

In 2021-22, $28 million was earmarked for Geothermal Resource Development and the Minerals Strategy, including mapping of targeted public geoscience information in Alberta and support for the AER to establish the regulatory frameworks for geothermal and minerals. Of the $28 million, $17 million was spent in 2021-22, which included $1.9 million on mineral regulation and $14.3 million on mineral mapping. Unused funding will carry over into future fiscal years.

Maps to Minerals Program

One key area to support Alberta's Minerals Strategy and Action Plan is increasing the amount and accessibility of geoscience information and data. Publicly accessible, robust, and current geoscience information provides all Albertans with a better understanding of the resource potential in Alberta. It will also contribute to attracting investment for exploration and development as it reduces exploration risk and contributes to well-informed resource development and land use decisions. Alberta has potential in many metallic and industrial minerals, such as lithium, uranium, vanadium, nickel, rare earth elements, potash, and diamonds; however, further mapping and exploration is required, as much of the province is under-mapped and under-explored for minerals.

Through a provincial grant, Alberta Geological Survey, which is a branch of the AER, was given $25 million in funding to survey and map Alberta's landscape. The Mineral Mapping program was initiated late in fiscal 2021-22, and work is currently underway to acquire and analyze geological information to improve our understanding of Alberta's mineral potential. Some of the activities include airborne geophysics, remote sensing, and analyzing current core, rock, and oilfield well water samples the AER has collected to map and better understand the mineral occurrences and potential in Alberta. Data will then be collated, analysed and interpreted, then made available on the Alberta Geological Survey website at: https://ags.aer.ca/

Canadian Mineral Collaboration

Alberta continues to work with the federal and other provincial and territorial governments, through the Critical Minerals and Battery Value Chain Task Force and Mines Intergovernmental Working Group, in pursuing Canada's approach targeting the critical minerals and battery value chains. These critical minerals initiatives, as well as other pan-Canadian initiatives under the Canadian Minerals and Metals Plan help advocate for Alberta's minerals opportunities, raise awareness around the Alberta government's initiatives, and position Alberta as a potential mineral supplier and manufacturer along the critical minerals value chains to support a low carbon future.

Geothermal Resource Development

Energy led efforts in establishing a geothermal regulatory framework to help diversify the energy sector, while creating jobs and supporting the province's recovery efforts. Using made-in-Alberta technical ingenuity and decades of drilling and geology expertise, this framework helps create the conditions for industry to safely and successfully harness clean energy from the earth.

In December 2020, the Government of Alberta passed Bill 36: *Geothermal Resource Development Act*. The act provides the Alberta Energy Regulator (AER) with authority to regulate the safe, efficient, and responsible development of Alberta's geothermal resources. The legislation clarifies industry requirements, establishes the AER's oversight authority, and establishes the government's ability to receive revenues, such as royalties and fees, for geothermal development. This was the first step in enabling a geothermal legislative framework. While in the process of developing a more permanent geothermal policy, Energy also offered an interim approach to facilitate more advanced geothermal projects to enter into the regulatory approval process. This interim approach provided opportunities for data collection and "stress-testing" of the policy elements for consideration.

Throughout 2021, Energy, along with Environment and Parks and the AER, advanced the development of required regulations and rules to support the proclamation of the legislation, established the AER as the lifecycle geothermal regulator, and administered and issued geothermal tenure rights. The *Geothermal Resource Development Act* was proclaimed and became effective on December 8, 2021.

New geothermal regulations, such as the Geothermal Resource Development Regulation and Geothermal Resource Tenure Regulation, and amendments to existing regulations such as Conservation and Reclamation Regulation, Specified Enactments (Jurisdiction) Regulation, and *Responsible Energy Development Act* General Regulation came to force on January 1, 2022. Developing geothermal regulations that align with other resource activities ensures a cohesive approach to responsible energy development across the province, while ensuring the regulatory regime is adaptive and flexible as this new sector unfolds.

As of March 31, 2022, Energy received 30 tenure applications and granted the first geothermal leases for exploration and development of Alberta's geothermal resources on March 24, 2022. Companies have expressed interest in exploring Alberta's geothermal potential. Having established legislation and a robust regulatory system will help further Alberta's economic recovery by attracting investment and creating jobs. Alberta is positioned to attract investment in this emerging industry due to its natural geographical advantage, world-renowned research and data, leadership in drilling technology, and extensive oil and gas expertise.

Throughout the development of regulations and AER Rules and Directives, Energy engaged key stakeholders in oil and gas, geothermal industry, landowners and surface rights holders, freehold mineral owners, Indigenous communities, and municipalities. In April 2021, the Government of Alberta conducted a stakeholder engagement session to further guide implementation and regulation development; this included inviting written submissions with respect to Alberta's geothermal liability management approach. In August 2021, government conducted a follow-up engagement session to test proposed geothermal tenure design and gather feedback to further inform regulation development and implementation.

The AER is currently finalizing their rules around geothermal development, which are anticipated to be ready in summer 2022.

In 2021-22, $28 million was earmarked for Geothermal Resource Development and the Minerals Strategy, including mapping of targeted public geoscience information in Alberta and support for the AER to establish the regulatory frameworks for geothermal and minerals. Of the $28 million, $17 million was spent in 2021-22, which included $1.3 million on geothermal regulation. Unused funding will carry over into future fiscal years.

Carbon Capture Utilization and Storage (CCUS)

Carbon dioxide (CO2) is a greenhouse gas that comes from burning fossil fuels, such as coal, oil and natural gas, through activities like driving a car or creating electricity. For large stationary sources of CO2, like an oil refinery, use of carbon capture, utilization and storage can help prevent these emissions from entering the atmosphere. Captured CO2 is injected into carefully selected sites deep underground for safe, long-term storage. Alberta is seeing rapidly growing interest in CCUS, and the Government of Alberta is carefully considering how CCUS will be developed in Alberta.

The Government of Alberta recognizes the value CCUS will bring to Alberta and the critical role it is playing in a low carbon economy - especially clean hydrogen. CO2 is a greenhouse gas pollutant, and needs to be reduced to meet any emissions reduction target/goal/commitment – by any particular company or by the federal government. CCUS is a necessary, yet not sufficient part of reducing Alberta and Canada's emissions. It is a technology that can be used across industries and sectors (hydrogen, petrochemicals, oil sands, cement, power, etc.). CO2 can be used for enhanced oil recovery operations, and assists in producing more of the resource that would otherwise not be produced using conventional methods.

Carbon Capture and Storage Program

In 2008, the Government of Alberta committed $2 billion to establish a Carbon Capture and Storage Program fund to incentivize the development of large-scale projects in Alberta, with the objective of storing up to five million tonnes of CO2 per year and reducing overall greenhouse gas emissions. Through a comprehensive selection process, four projects were chosen to receive the allocated funding; however, only two projects decided to proceed with their plans: the Quest and the Alberta Carbon Trunk Line projects. For these two projects, $1.24 billion in funding allocated to the end of 2025 to capture approximately 2.76 million tonnes of CO2 each year. This is roughly equivalent to annual emissions of 600,000 vehicles. Yearly presentations and annual reports are also completed by Quest and the Alberta Carbon Trunk Line. Project learnings are shared through a knowledge sharing program that helps to reduce the future costs of CCUS and the broader adoption of this technology around the world – summary and detailed reports for the knowledge sharing program are submitted annually on or before April 1. For the first time, the 2020 Quest and Alberta Carbon Trunk Line Knowledge Sharing documents included information on the cost per tonne of CO2 (both captured and avoided). These reports are available at www.alberta.ca.

Previous work by the Government of Alberta on CCUS includes the Carbon Capture and Storage Program, which was initiated in 2008 and continues to realize benefits for Albertans. Over the 2021-22 fiscal year, annual injection payments for the Alberta Carbon Trunk Line project and the Quest project totaled approximately $43 million. The funding provided to the two projects will allow them to capture up to a combined 2.76 million tonnes of CO2 per year. The amount of the greenhouse gas emission reductions are certified by third party verifiers.

Quest Project Update: The Quest project is capturing approximately a million tonnes of CO2 per year from the Shell Scotford Upgrader, transporting it 65 km north by pipeline and permanently storing it underground in a deep saline aquifer. As of 2021, the Quest project completed its sixth year of CO2 injection. Since entering operation in 2015, the project has exceeded its targets for the capture and safe, permanent storage of CO2 at a lower-than-anticipated cost.

Alberta Carbon Trunk Line Project Update: Having achieved commercial operation in May 2020, the Alberta Carbon Trunk Line project is now transporting over one million tonnes of CO2 captured from the North West Sturgeon Refinery and the Nutrien Redwater Fertilizer Plant, through a 240-km pipeline, for use in enhanced oil recovery in Clive, Alberta. Designed with the expectations to hook up to many new CO2 producers in the future, the pipeline has the potential to transport up to 14.6 million tonnes of CO2 annually. In April 2021, Enhance Energy, the owner and operator of the utilization and storage portion of the project, received approval from Energy and the AER on an updated monitoring, measurement and verification plan, which will allow them to expand the area of injection in the Clive oilfield. As the Alberta Carbon Trunk Line is an enhanced oil recovery project, it holds a conventional Petroleum and Natural Gas (PNG) lease, and does not pay into the Post-Closure Stewardship Fund.

The Post-Closure Stewardship Fund

The Post-Closure Stewardship Fund is administered by the department and financed by carbon capture, and storage operators in Alberta. The fund will help ensure that the storage sites are properly maintained, over the long term, after operations cease, and to offset the costs of the government's obligations, particularly in the post-closure period. Those operators that obtain a lease under the Carbon Sequestration Tenure Regulation are required to contribute to the fund. The amount paid into the fund is based on a project-specific rate per tonne of CO2 injected into the sequestration lease each year. However, in 2022, this rate will undergo its periodical update, which ensures that the cost of the amount collected is equivalent to the Government of Alberta's obligations. This update adjusts the changing values, incorporating interest and inflation rates and the expected costs of future activities.

To date, the Post-Closure Stewardship Fund has collected six annual injection levy payments from the Quest project. The fund is currently valued at $1.67 million after collecting $218,000 in levy payments in 2021-22.

As the Alberta Carbon Trunk Line is an enhanced oil recovery project, it holds a conventional PNG lease, and does not pay into the Post-Closure Stewardship Fund.

Carbon Sequestration Tenure Management

CCUS is critical to clean hydrogen development, low carbon oil sands development, petrochemicals, and other large emission industries. The department has received significant interest from industry for the authorization to use pore space for the sequestration of CO2. The pore space used for CCUS are carefully selected, secure underground geological formations that can safely and permanently store the captured CO2. As the areas impacted can be very large, ensuring a well-defined and strategic approach to make sure CO2 storage options are available and accessible to all industries is essential.

The province is advancing a strategic hub concept through a competitive process. A carbon sequestration hub will be an area of pore space overseen by a private company that can effectively plan, enable, and undertake carbon sequestration of captured CO2 from various emissions sources as a service to industrial clients. Having an industry steward of the location, with the oversight of Alberta's regulatory system, will work toward efficient use of the pore space and support strong modelling, monitoring, and risk management practices. Successful proponents will be expected to have the technical, financial, and operational capacity to manage such an important aspect of Alberta's energy system, and will be responsible for obtaining all necessary regulatory approvals, and ensuring the safe and effective operation and closure of the hub, enabling sequestration services to Alberta's industrial sector at fair service rates. This program will encourage investment and job creation by giving CCUS proponents the sequestration tenure rights to proceed with the planning, construction and operation of their projects.

Energy solicited Expressions of Interest from stakeholders to gather information on proposed CCUS projects in fall 2021, then at the beginning of December 2021 Energy released the first Requests for Full Project Proposals (RFPP) for CCUS projects that would sequester emissions from the Industrial Heartland Region, which resulted in six successful applicants:

- Meadowbrook Hub Project, Bison Low Carbon Ventures Inc. for a potential sequestration hub north of Edmonton
- Open Access Wabamun Carbon Hub, Enbridge Inc. for a potential sequestration hub west of Edmonton
- Origins Project, Enhance Energy Inc. for a potential sequestration hub south of Edmonton

- Alberta Carbon Grid™, Pembina Pipeline Corporation and TC Energy for a potential sequestration hub north and northeast of Edmonton
- Atlas Carbon Sequestration Hub (Atlas Hub), Shell Canada Limited, ATCO Energy Solutions Ltd., Suncor Energy Inc., for a potential sequestration hub east of Edmonton
- Wolf Midstream and partners for a potential sequestration hub east of Edmonton

Companies will be invited to work with government to further evaluate the suitability of each location for safely storing carbon from industrial emissions. If the evaluation demonstrates that the proposed projects can provide permanent storage, companies can work with the government on an agreement that provides them with the right to inject captured CO2. This agreement will also ensure they provide open access to all emitters and affordable use of the hub. The Alberta Energy Regulator will ultimately approve only projects that meet Alberta's rigorous safety and environmental standards.

At the beginning of March 2022, the department released the second RFPP for CCUS projects that would sequester emissions for the rest of Alberta. CCUS stakeholders who are selected to move forward with projects will benefit from surety provided by this program. Albertans will benefit from reduced CO2 emissions once the program is up and running,

A contract for up to $75,000 was procured to provide fairness monitoring services for the competitive process. The fairness monitor provided advice and support in designing and conducting a fair process to select CCUS proposals.

For more information, visit: https://www.alberta.ca/carbon-sequestration-tenure-management.aspx

Sturgeon Refinery

Sanctioned in 2012, the objective of the Sturgeon Refinery was to process bitumen into diesel and other value added products. The Alberta Petroleum Marketing Commission (APMC), an agent of the Government of Alberta, has a binding 40-year tolling commitment, as amended on June 30, 2021, to provide bitumen to the refinery that will be processed into refined products – primarily ultra-low sulphur diesel – and in return pay a cost-of-service toll.

On June 30, 2021, APMC executed an Optimization Transaction where APMC acquired 50 per cent ownership of the Sturgeon Refinery enabling the Government of Alberta to capture the value of processing bitumen as both a toll payer and as an owner of the facility. The Transaction improves the government's net present value for the refinery by approximately $2 billion over the life of the project and frees up $1 billion in cash flow to the government over the next five years. The restructured deal also reduces previous operational risks by aligning the refinery's toll payer/ownership structure.

With this Optimization Transaction, the government has an equal vote in the control of the refinery to which it is the majority toll payer, enabling greater government returns in the project's upside. The APMC continues to manage the government's commitment to the Sturgeon Refinery, including the responsibility for providing 75 per cent of the bitumen feedstock to the refinery and managing the Government of Alberta's 50 per cent ownership position. Canadian Natural Resources Limited (CNRL), the other 25 per cent toll payer and 50 per cent owner, continues to provide operational leadership to the refinery, working to maximize efficiency and production capacity.

Starting in November 2017, the Sturgeon Refinery was processing synthetic crude oil into diesel and other valuable products as part of the commissioning and start up process. The refinery reached commercial operations on June 1, 2020 and at that point began processing bitumen, rather than synthetic crude oil, into diesel in the following amounts per calendar year:

- total diesel production was 11.0 million barrels in 2019
- total diesel production reached 11.8 million barrels in 2020
- total diesel production reached 13.1 million barrels in 2021

The refinery has a capacity of 79,000 barrels per day of diluted bitumen feedstock, which is equivalent to 50,000 barrels per day of bitumen. Sturgeon Refinery will add value to the resources Albertans own and further demonstrate Alberta's contribution to commercial-scale carbon capture and storage. The refinery produces low carbon diesel and has added a significant number of well-paying jobs to the economy, providing more than 400 jobs related to the long-term operation of the facility.

For 2021-22, the non-cash provision is $0.35 million based upon net present value calculations. As of March 31, 2022, the APMC has $1.1 billion outstanding that was borrowed from Treasury Board to fund APMC's ongoing activities with the Sturgeon Refinery. During fiscal 2021-22, APMC repaid $254 million of net repayments from free cash flows from the Sturgeon Refinery. Returns will be predominately affected by commodity prices for refined products and feedstock and foreign exchange. In addition, returns will be impacted by how well the refinery operates, as measured by the onstream factor. The APMC, with its partner CNRL, continues to improve refinery performance to maximize profitability and value to government and Albertans.

Clean Fuel Regulation

The federal government's Clean Fuel Regulation (CFR) is intended to reduce the lifecycle emissions from gasoline and diesel fuels used in Canada, stimulate investment and innovation in low-carbon intensity fuels and technologies, and minimize compliance costs through various compliance options.

In 2021-22, Energy supported Environment and Parks in engaging with the federal government on the draft CFR, including:

- providing technical and policy input to address potential unintended consequences, including lost investment and revenue to other jurisdictions and increased risk for trade-exposed industries;
- advocating and pressing for revisions to the CFR that enhance competitiveness and reduce the creation of additional red tape; and
- advising on ways to ensure the CFR is outcome based as opposed to prescriptive on the basis of technology.

Publically available analyses have highlighted the risks to refineries and increasing input costs due to compliance with the CFR, which could increase costs for consumers by 8 to 15 cents per litre of liquid fuel by 2030. Liquid fuel refiners will face higher long-term compliance costs. Costs are expected to rise significantly starting in approximately 2025 when the regulatory obligations require more action than the expected low-cost and business-as-usual compliance options can satisfy. While the CFR could lead to investment opportunities in the oil and gas sector (like carbon capture and storage, bio crude co-processing, hydrogen production and low carbon electricity), the current design of the CFR, on its own, does not provide the investment certainty that is required to get these projects off the ground.

The province is continuing to work closely with industry stakeholders to ensure it is accurately and effectively incorporating their perspectives into the province's engagement policy.

Key Objective 1.3

Enhance Alberta's investment climate through measures to improve the province's standing with investors and support economic recovery, such as:

- continuing to invest in job creation through environmental stewardship by providing support to site rehabilitation and orphan wells;
- reducing red tape while streamlining legislative requirements and regulatory processes; and
- ensuring Alberta's safe, reliable electricity system provides competitive electricity rates for investors and Albertans to support the creation of jobs in the economy and attract investment as electricity costs are a factor in attracting and retaining investment in most sectors.

Site Rehabilitation Program (SRP)

The SRP launched on May 1, 2020, accessing up to $1 billion from the Government of Canada's COVID-19 Economic Recovery Plan. It provides relief funding to eligible oil field service workers to perform well, pipeline, and oil and gas site closure and reclamation work. The SRP supports economic recovery by increasing employment in the oilfield service sector and enhancing Alberta's investment climate, while also decreasing the environmental liability associated with oil and gas development. An Industry Advisory Committee, including representatives from the Indian Resource Council, was established to provide advice and feedback on the program. A roundtable with Indigenous oil field service companies has also been established to help connect communities with Indigenous oil field services and to provide two-way communication and information on the program.

The SRP is expected to generate almost 5,300 direct jobs and lead to indirect employment and economic benefits across the province, as other businesses will benefit from the increased clean-up work occurring in many rural areas. Grant funding was made available in the five open funding periods in 2021-22, each with targeted priorities, application criteria, and timelines:

Closed Periods from the 2020-21 fiscal year:

- Period one made $100 million in funding available from May 1, 2020 to May 15, 2020. Grant applications were accepted for oil and gas sites needing abandonment and/or reclamation across Alberta for projects that required 100 per cent government funding with contracts of up to $30,000 (per application, per closure activity). As period two was not fully subscribed, $83 million of available funding was reallocated to period one, and a total of $183 million in funding was allocated.
- Period two made $100 million in funding available from May 15, 2020 to June 15, 2020. Grant applications were accepted for oil and gas sites on land where government is paying compensation to landowners as required under Section 36 of the *Surface Rights Act* for projects that require 100 per cent government funding, with no contract cost limit. Of the available funding, $15.4 million in funding was allocated to 63 companies, with another $83 million reallocated to period one.
- Period three made $100 million in funding available from July 17, 2020 to March 31, 2021, or until licensees fully expended their allocations. Grant applications were accepted for up to $139,000 in funding for each active site licensee in the province. Oil field service contractors could contract with these licensees to do closure work and apply for an SRP grant to get funding to do the work and were eligible for 100 per cent grant funding. Of the funding available, $54.1 million in funding was allocated to 279 companies.

Open Periods in the 2021-22 fiscal year:

- Period four made $100 million in funding available from August 7, 2020 to March 31, 2022, or until allocations are fully subscribed. The closing date was extended from September 30, 2021 to March 31, 2022. Grant applications are accepted for licensees who have submitted either confirmed or proposed Area-Based Closure plans to the Alberta Energy Regulator. Projects are eligible for up to 50 per cent grant funding, with the licensee responsible for paying the remaining cost. Grant funding is increased up to 100 per cent of the project value if the licensee contracts with Indigenous oil field service companies. As of March 31, 2022, $96.8 million of the available funding was allocated to 226 companies.
- Period five made $300 million in funding available from February 2021 to March 31, 2022, or until allocations are fully subscribed. Licensees with confirmed hydrocarbon production in 2019, and that spent corporate funds doing closure work in 2019 or 2020, have been allocated SRP grant funding amounts for period five. Projects are eligible for up to 50 per cent grant funding. Grant funding will be increased up to 100 per cent of the project value if contracted with Indigenous oil field service companies. In January 2022, the period five allocations were increased by a third for a total of $400 million in available funding using underutilized funds from existing periods. As of March 31, 2022, $302.4 million of the available funding was allocated to 252 companies.
- Period six made $100 million in funding available from February 12, 2021 to May 2, 2022, provided applications match work already received in allocation trackers submitted by March 31, 2022. First Nations that have each been allocated a portion of $85 million in SRP closure funding, and Metis Settlements have each been allocated a portion of $15 million in SRP closure funding, to work with licensees and applicants to close sites on reserve and on settlement. Out of these total allocations, First Nations allocations were developed in cooperation with the Alberta member First Nations of the Indian Resource Council and are distributed based on the number of eligible well licenses on each First Nations reserve, in proportion to the total number of eligible wells in all First Nations where eligible wells are located. Metis Settlements allocations were developed in cooperation with the Metis Settlements General Council office and are distributed based on the number of eligible well licenses on each Settlement, in proportion to the total number of eligible well licenses on all Settlements. First Nations communities and Metis Settlements approve the sites that are eligible for closure work using their allocation, and work with licensees and contractors to approve the associated spending. Once this is done, the First Nations and Metis Settlements inform Energy which licensees are eligible for SRP funding, and for how much. Contractors can then apply directly to government for SRP grants to do the work. In January 2022, the period six allocations were increased by a third for a total of $133 million in available funding, using underutilized funds from previous periods. As of March 31, 2022, $59.1 million of the available funding was allocated to 40 companies.
- Period seven made $100 million in funding available from August 9, 2021 to March 31, 2022, or until the allocations are fully subscribed. This funding was made available for post-abandonment closure work on two categories of sites: those abandoned prior to April 30, 2017, and nominated sites with abandoned wells, facilities or pipelines abandoned prior to April 30, 2017. Licensees with eligible abandoned sites have been allocated SRP grant funding amounts for period seven. Projects are eligible for up to 50 per cent grant funding. Grant funding will be increased up to 100 per cent of the project value if contracted with Indigenous oil field service companies. As of March 31, 2022, $50.9 million of the available funding was allocated to 105 companies.
- Period eight made $100 million in funding available from August 9, 2021 to March 31, 2022, or until the allocations are fully subscribed. This funding was made available for closure work in Sage Grouse, native trout and caribou Species at Risk in specific geographic areas identified. One-third of the $100 million in

funding has been allocated to each of the three Species at Risk (Sage Grouse, native trout and caribou). Licensees with eligible sites in the identified geographic areas for each species have been allocated SRP grant funding amounts for period 8. Projects for post-abandonment work activities are eligible for up to 100 per cent grant funding. Abandonment projects will be accepted within the identified Sage Grouse area and are eligible for up to 50 per cent of grant fund. As of March 31, 2022, $36.6 million of the available funding was allocated to 63 companies.

As of March 31, 2022, over $780.0 million in grant funding has been approved and is being allocated to 579 Alberta-based companies, creating over 3,700 jobs so far. A total of 32,791 applications have been approved. Of the total approved:

- $477.5 million has been allocated for 26,386 abandonment sites,
- $20.6 million has been allocated for 13,781 Phase 1 environmental site assessments,
- $67.7 million has been allocated for 4,402 Phase 2 environmental site assessments,
- $56.8 million has been allocated for 981 remediation sites, and
- $157.4 million has been allocated for 9,823 reclamation sites.

Taking an incremental approach to making the funding available through different periods was critical to success, allowing feedback and lessons learned to be incorporated into each round.

With more work to do, Government of Alberta requested that the previous timelines be extended. As announced on April 6, 2022, the federal government granted an additional 45 days for the Site Rehabilitation Program. This will allow more time for the processing of applications received by March 31, and will provide a few extra weeks for companies to carry out clean-up work. For more information, visit https://www.alberta.ca/site-rehabilitation-program.aspx

Methane Emissions Reduction

Alberta was the first sub-national jurisdiction in North America to commit to an oil and gas methane reduction target, committing in 2015 to an oil and gas methane reduction target of 45 per cent by 2025 from 2014 levels. Shortly thereafter, the federal government announced a similar target of 40 to 45 per cent by 2025 from 2012 levels.

Alberta companies continue to show great leadership, using innovative technologies and industry expertise to reduce methane emissions. Since the start of 2020, the Government of Alberta has also made more than $270 million available for methane reduction projects, including $57 million from the TIER fund. The Government of Alberta's January 2022 Methane Emissions Management report, which includes data from the 2020 reporting year, shows Alberta has achieved a 34 per cent methane emissions reduction from 2014 levels, putting Alberta on the path to reach its 2025 target of a 45 per cent reduction.

As part of their election platform, the federal government set a new target of a 75 per cent reduction in methane emissions by 2030 from 2012 levels for the oil and gas sector. Energy is actively supporting Environment and Parks to ensure Alberta is able to continue operating in a way that maintains jurisdiction with Alberta-based approaches to methane that are cost-effective and maximize benefits to all Albertans.

Alberta's Electricity Market

Alberta's electricity system is critical to support the province's economic recovery from COVID-19.

The Government of Alberta is committed to maintaining a safe, reliable and affordable electricity system for all Albertans. This means working with stakeholders to determine where the system needs to be modernized to meet the needs of consumers and investors. Government made significant progress in identifying gaps in the current legislative framework, ensuring the continued support of technical innovations and providing the needed clarity for investors, electricity agencies, and Albertans. Energy conducted significant engagement with impacted stakeholders – including consumer associations, investors, utility companies and other interested organizations – to better understand the nuanced perspectives that impact policy decisions in this sector.

A culmination of engagement on self-supply with export policy, energy storage, and distribution planning resulted in Bill 22, *Electricity Statutes (Modernizing Alberta's Electricity Grid) Amendment Act*, which passed the legislature in May 2022. A similar bill was initially introduced in the fall of 2021, and was amended based on stakeholder feedback to ensure it better fulfills the policy intent of enabling technological innovation while also protecting existing investment and overall consumer costs.

The *Electricity Statutes (Modernizing Alberta's Electricity Grid) Amendment Act* will encourage the adoption of new technologies and create a planning framework to improve distribution, while still making sure that infrastructure costs borne by Alberta ratepayers are reasonable and fair. The legislation will also begin winding down the Balancing Pool by redistributing its remaining responsibilities and laying the groundwork for its dissolution.

Together, the proposed legislative amendments will help to continue to build investor confidence in Alberta's electricity grid and support a modern and innovative electricity system, giving industry further options to control their electricity costs and long-term price stability for consumers.

The act harnesses market forces to support Alberta's electricity system in meeting the evolving needs of consumers and create a low-carbon future through investment from industry rather than costly subsidies from taxpayers. The act enables the integration of energy storage into Alberta's interconnected electric system as a technology that can participate in either the competitive electricity market or the transmission and distribution system. It also enables electricity generation for unlimited self-supply with export while ensuring that transmission system costs are balanced among all system participants.

The act initiates work to define a long-term planning framework for the distribution system by requiring distribution facility owners to develop long-term plans and enabling the Minister to develop regulations outlining the specifics of the long-term plans. This builds on the Alberta Utilities Commission's Distribution System Inquiry, which in its final report released in February 2021, pointed to the need for the province to develop a long-term planning framework to better integrate distributed energy resources.

The act transfers all non-expiring Balancing Pool business to other entities. This includes all the agency's responsibilities, except Power Purchase Arrangements (PPAs) related business, and H.R. Milner Decommissioning and its funding mechanisms, which remain with Balancing Pool.

The Government also initiated broad engagement on transmission policy, with a focus on enabling policy that optimizes use of the current transmission system, ensuring an efficient and cost effective future system, and maintaining investor confidence in Alberta's electricity sector.

Alberta's energy-only market-based system continues to attract investment without additional government financial support.

Renewable Electricity

The Government of Alberta welcomes market-driven renewables – like wind, solar, hydro, geothermal and biomass – that can compete with other forms of power production. Alberta's long-standing commitment to a fair, efficient and openly competitive electricity market has created the conditions for market-based renewables to expand and be profitable within Alberta. There has been significant growth in market-based renewable energy because of the government's environmental policies, electricity market, and the falling costs of wind and solar technology.

Renewable energy resource means an energy resource that occurs naturally and that can be replenished or renewed within a human lifespan, including, but not limited to (i) moving water, (ii) wind, (iii) heat from the earth, (iv) sunlight, and (v) sustainable biomass. In 2020, 12.41 per cent of total generation was renewable electricity. The data is just starting to show the growth in renewable energy. The 2021 data for renewables will be released in mid-2022 by the Alberta Utilities Commission.

The implementation of the Technology Innovation and Emissions Reduction (TIER) regulation has accelerated investment in market-based renewables by ensuring they benefit from providing emissions-free electricity to Alberta. Alberta has seen over $2 billion worth of utility scale renewable generation projects, representing over 1,200 megawatts of new generation, announced since 2019. This growth in renewables is funded by private investors, not government subsidies – meaning there is no associated public debt.

The Government of Alberta will also continue to honour the contracts under the Renewable Electricity Program (REP), implemented by the previous government. The program utilizes a contract for difference design, where confidential strike prices are contractually agreed to with each REP participant. The government receives revenue when electricity pool prices are higher than the strike price and is obligated to fund generators when the pool price is lower than the strike price. The program has provided government approximately $36 million in revenue since inception due to electricity prices being significantly higher than anticipated by the project developers.

Balancing Pool

The Balancing Pool was established by the Government of Alberta in 1999 to manage Power Purchase Arrangements (PPAs) when Alberta deregulated its electricity market. There were very few generators in the market at the time, all with strong market positions. PPAs were created as a transition mechanism to promote competition in the newly created energy-only market by separating the right to sell power from the ownership of the power plant and auctioning it to outside parties. These contracts gave the buyers the right to purchase electricity generated by contracted generators at a fixed price for a specified period of time. Electricity purchases through these PPAs were sold in the wholesale electricity market at the pool price. When the pool price was above the contracted price, the PPAs generated revenue, and when the pool price was below the contracted price, the PPAs lost money.

With the expiry of the PPAs at the end of 2020, the main responsibility of the Balancing Pool has concluded. In 2021-22, the Balancing Pool's mandate was reviewed for ongoing relevancy and to ensure it continued to serve in the best interest of Albertans, and it was determined that it would be appropriate to begin the process of dissolving the Balancing Pool. A staged dissolution plan has been developed that will transfer ongoing responsibilities of the Balancing Pool to other entities and maintain the Balancing Pool with a limited scope until expiring responsibilities are completed. *Alberta's Electricity Statutes (Modernizing Alberta's Electricity Grid) Amendment Act* enables this dissolution, with further changes to be implemented through regulations.

In the short term, the Balancing Pool will be downsized but will still fulfill necessary roles and responsibilities in the electricity system. Red-tape reduction and cost savings will be achieved when the dissolution plan is executed and expiring responsibilities wind down naturally. At that time, the Balancing Pool can be eliminated, including its board, corporate services, and all obligations associated with having a standalone agency.

Natural Gas Rebate Program

On February 24, 2022, the Natural Gas Rebate Program was announced as part of Budget 2022. The Government of Alberta is developing an innovative energy rebate program for next winter to help Albertans manage higher heating costs. This is part of the government's commitment to support Albertans through the province's economic recovery, and in response to global increases to the costs of natural gas. The rebate will go towards the costs of natural gas for the months of October 2022 through to March 2023. Consumers with less than 2,500 gigajoules of annual natural gas consumption will be eligible. This threshold includes most households, small apartment buildings, farms, as well as small industrial and commercial operations.

The rebate program will be triggered if regulated natural gas companies charge Albertans regulated monthly natural gas rates above $6.50/GJ. Additional details are being determined and will be released prior to the program launching in October 2022.

Electricity Rebate Program

On March 7, 2022, the Government of Alberta announced an Electricity Rebate Program. Many Albertans facing high electricity bills in winter 2022 reached out to the government to express their concerns, and in response the Government of Alberta will be providing $150 in electricity rebates ($50 rebate for three months) to more than 1.9 million homes, farms and businesses. Targeted relief will be provided for residential, farm, and small business customers who consume less than 250 megawatt hours per year. Exact eligibility criteria for the program is specified in the Utility Commodity Rebate Regulation, which came into force in May 2022.

Utility Payment Deferral Program (UPDP)

In March 2020, the Government of Alberta announced the UPDP, which allowed residential, farm and small commercial utility ratepayers to defer utility payments until June 18, 2020 – a period of 90 days - and that utility services would not be cut off or reduced during this period for non-payment. Consumers eligible for the deferral program included anyone who was experiencing financial hardship and could not make regular payments as a result of COVID-19 pandemic. This deferral applied to bills for residential, farm and small commercial service:

- Electricity consumers, who consume less than 250,000 kilowatt hours of electricity per year.
- Natural gas consumers, who consume less than 2,500 gigajoules per year.

During the period from March 18 to June 18, 2020, there were approximately 181,000 customers enrolled in the natural gas deferral program and about 245,000 customers enrolled in the electricity deferral program, representing 16 per cent of each consumer base. The program applied to bills for residences, farms, and small businesses. In addition, the government ensured that no Albertan was cut off from these services or saw their services reduced while the program was in place. Participants of the program had until June 2021 to repay their deferred payments. The default repayment plan for all consumers was 12 equal monthly installments, interest free. Alternatively, customers had the option of contacting their utility provider to discuss an alternate repayment plan.

All outstanding payments that remained unpaid after June 18, 2021 were added to a small, temporary rate rider – a fee paid by all utility customers in the province – with one for natural gas and one for electricity. Rate riders are commonly used to address unanticipated costs incurred by a regulated utility provider. The Alberta Utilities Commission coordinates the rate rider process and finalizes the total cost based on the outstanding amounts owed through the deferral process, and on August 18, 2021, the AUC issued a decision regarding the implementation of UPDP rate riders. The AUC determined the rider amount would be approximately $8.77

million for electricity and $6.10 million for natural gas. The AUC completed the rate rider collection for electricity and natural gas on February 28, 2022.

From November 2021 to February 2022, "Utility Deferral Adjustment" rate riders – one for electricity and one for natural gas – appeared on consumer utility bills:

- Electricity rate rider – 0.045 cents per kilowatt-hour (an average residential consumption of 600 kilowatt-hour pays 27 cents per month).
- Natural gas rate rider – 3.7 cents per gigajoule (an average residential winter consumption of 21 gigajoules pays 78 cents per month).

Small Modular Reactor Memorandum of Understanding (MOU) and Strategic Plan

On April 14, 2021, the Government of Alberta signed a MOU with New Brunswick, Ontario and Saskatchewan to support the development of small modular nuclear reactors (SMRs). A key action identified in the MOU is the development of a joint strategic plan.

On March 28, 2022, the governments of Alberta, Ontario, Saskatchewan and New Brunswick agreed to a joint strategic plan outlining the path forward on small modular reactors (SMRs), including five key priority areas for SMR development and deployment:

- Positioning Canada as an exporter of global SMR technology by propelling three separate streams of SMR development, covering both on-grid and off-grid applications.
- Promoting a strong nuclear regulatory framework that focuses on the health and safety of the public and the environment while ensuring reasonable costs and timelines.
- Securing federal government commitments on financial and policy support for new SMR technologies that would lead to vast economic benefits across the country and help meet the Government of Alberta's emissions reduction targets.
- Creating opportunities for participation from Indigenous communities and public engagement.
- Working with the federal government and nuclear operators on a robust nuclear waste management plan for SMRs.

The partner provinces will continue to work together and across the nuclear industry to help ensure Canada remains at the forefront of nuclear innovation while creating new opportunities for jobs, economic growth, innovation and a lower-carbon future.

Canadian Energy Centre (CEC)

The CEC was created by the Government of Alberta in 2019 as an independent provincial corporation under the *Financial Administration Act*. It has a mandate to respond to misinformation about Canadian oil and natural gas, create original content to elevate the general understanding of Canada's energy sector, and to centralize and analyze data that targets investors, researchers and policymakers.

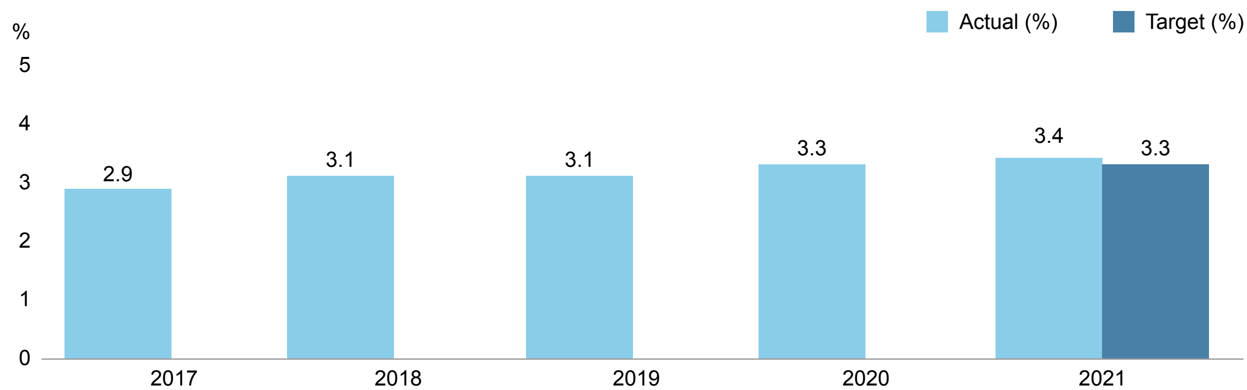
The CEC promotes energy literacy, and responds quickly and factually to misinformation about Canada's energy industry. The CEC engaged in information campaigns and produced original content on issues including Indigenous involvement in the energy industry, industry innovation in environmental protection, and benefits of responsibly produced Canadian energy to the world. This work has taken on increased importance with the Russian invasion of Ukraine, and the broad concern for energy security by Western nations taking on a vital importance.

In the 2021-22 fiscal year, expenditures were $4.16 million. Highlights of the CEC's achievements in 2021-22 include:

- Reached over 1.5 million Canadians per month through all its social media channels using graphics, videos, rapid response communications products and content highlighting the impact oil and gas has on the individual lives of Canadians across the country.
- Significantly increased its email database to more than 40,000 supporters, double what it was the previous year. These supporters send letters, sign pledges, and work to ensure the good news story of Canadian energy moves across Canada.
- Ran the friendly energy campaign in Times Square and other strategic locations in New York and Washington D.C. The campaign reminded Americans there is secure, reliable and environmentally sound oil and gas north of the border. It was viewed by more than 12 million people.
- Launched the YouTube video campaign, Oil & Gas Always On, consisting of three videos that were seen 1.5 million times over three weeks.
- The CEC mounted a counter-campaign that brought attention to the large number of Indigenous voices that supported the Coastal Gas Link Pipeline and highlighted the strenuous efforts by the company to affix and adhere to rigorous environmental measures during construction. This was in response to anti-oil and gas groups' "week of action" in December 2021, which was intended to falsely demonstrate allegedly illegal activity by the RCMP and company officials to run roughshod over peaceful Indigenous protestors.
- To promote a balanced conversation about the energy mix, and what is possible in the short-, medium- and long-term, the CEC also promoted alternate energy forms, including hydrogen and small modular nuclear reactors.

Performance Measure 1a: Alberta oil sands supply share of global oil consumption.

Target: 3.3 per cent of global oil consumption is supplied by Alberta's oil sands.



Sources: Alberta Energy Regulator; International Energy Agency[8]

Discussion of Results

Development of Alberta's oil sands, and its role in the global energy mix, is part of a highly complex system, in which policy must balance multiple priorities while it adapts to changing global dynamics.

There are several levers available to the Government of Alberta, which indirectly impact the results of the measure. Key levers are the fiscal and royalty regimes, which directly act to incent industry's resource development activities while ensuring that Albertans receive direct financial benefits in the form of taxes and royalties. In addition, there are other government policies that influence industry performance, and therefore oil sands production levels, including promotion of market access, intergovernmental relations, energy research and development, and environmental regulations.

The 2021 supply share reached 3.4 per cent, and exceeded its target of 3.3 per cent. The rate of global year-over-year oil consumption increased by 6.1 per cent from 90.9 million bpd[9] in 2020 to 96.4 million bpd in 2021, as the oil demand gradually recovered with eased global COVID-19 restrictions.

Total crude bitumen production in Alberta increased from 2020 to 2021, from about 2.98 million bpd to 3.26 million bpd. The production result in 2021 was an annual record, exceeding the previous record of 3.10 million bpd that was set in 2019. Overall, Alberta's total crude bitumen production increased by 9.4 per cent from 2020 to 2021. As the rate of growth in the bitumen production from 2020 to 2021 in Alberta was higher than the rate of growth in global consumption, Alberta's oil sands supply share of global oil consumption increased to 3.4 per cent in 2021, and exceeded the target by about 0.1 per cent.

The increase in crude bitumen production in Alberta took place as the impacts of COVID-19 pandemic in 2021 were less pronounced than in the previous year. The demand for oil, including the demand in Alberta's traditional market, the United States, experienced some recovery. Also, COVID-19 mitigation measures and safety practices at the oil sands facilities were well in place by 2021, minimizing any disruption and helping to increase production.

[8] For more information, see the Performance Measure and Indicator Methodology section of this report on page 86.

[9] Previous, 2020-21 Annual Report reported 91.0 million bpd of global oil consumption for 2020. This volume has been retroactively revised to 90.9 million bpd.

Although both mined and in-situ production experienced an increase, in-situ production grew at a faster pace. Year-over-year growth rates were 11.6 per cent for in-situ production and 7.3 per cent for mined production. In-situ production increased from 1.49 million bpd in 2020 to 1.66 million bpd in 2021, and mined production increased from 1.48 million bpd in 2020 to 1.59 million bpd in 2021.

As a result of a more rapid growth of in-situ production in 2021, the proportion of in-situ and mined production in Alberta was slightly adjusted. In 2020, both mined and in-situ production accounted for about 50 per cent of total bitumen production in the province in 2020, with in-situ production accounting for a marginally larger share of production. In 2021, in-situ production and mined production accounted for about 51 per cent and 49 per cent of total bitumen production in the province, respectively.

Outcome Two:

Effective, efficient stewardship and regulation of Alberta's energy and mineral resources.

What it means:

The ministry will improve the clarity and efficiency of Alberta's energy regulatory system, while modernizing legislation and regulations to enhance the competitiveness of the Alberta energy sector, win back the confidence of investors and create jobs. A strategic and integrated system approach to responsible resource development balances the overall environmental, economic and social outcomes for the benefit of Albertans while ensuring the province has a predictable and streamlined regulatory environment that is attractive to investors and does not include unnecessary red tape and regulatory burden.

Key objectives to support this outcome included:

2.1 Collaborate with other ministries to maintain and strengthen a balanced, sustainable approach to managing the cumulative effects of resource development, including implementation of the liability management framework.

2.2 Optimize regulation and oversight of:

- Alberta's energy and mineral resource sector to utilize and develop resource potential in a responsible manner; and
- Alberta's utilities to ensure interests of Albertans are protected.

Key Objective 2.1

Collaborate with other ministries to maintain and strengthen a balanced sustainable approach to managing the cumulative effects of resource development, including implementation of the liability management framework.

Liability Management Framework

Along with Environment and Parks, industry, and Albertans, Energy continued to address the liability management challenges facing energy development. A large focus of this work was operationalizing the new Liability Management Framework for upstream oil and gas. Alberta's former approach to governing the clean-up of these wells was put in place decades ago, when the oil and gas industry was developing and largely focused on growing production and building core infrastructure. As the province's oil and gas sector has matured, a new framework was required to more actively manage site closure and anticipated liability throughout the development life cycle. This means working on existing sites that require clean up and preventing new sites from joining the inactive and orphan inventories in the future.

Announced by the Government of Alberta in July 2020, the new framework includes both short- and long-term initiatives to address the root, and not only the symptoms, of an issue that all energy-producing jurisdictions are facing. This approach is designed to establish significant long-term change, while at the same time, striking an important a balance. Ensuring that the clean up of inactive wells is addressed by producers in a manageable and sustainable way will shrink the inventory of inactive and orphaned wells across the province and create thousands of jobs for Albertans. The framework is the result of a comprehensive multi-year review undertaken by the Government of Alberta. This process included extensive engagement with a wide range of partners including industry, the financial community, environmental groups, municipalities, Indigenous communities, and landowners.

The polluter-pays principle is foundational to liability management in Alberta and is embedded within the new framework. This demonstrates Alberta's commitment to ensuring that clean-up costs will remain the responsibility of industry. It is anticipated that many of the challenges associated with oil and gas liability management will be addressed efficiently through the new framework. Setting clear expectations throughout the lifecycle of oil and gas projects, the framework ensures that industry is better-able to manage clean up of oil and gas wells, pipelines and facilities at every step of the development life cycle – from exploration and licensing, through operations, reclamation, and post-closure. Clarifying the rules and proactively working with struggling operators, provides industry with the certainty needed to make long-term investment decisions and protects landowners and communities by ensuring more timely restoration of land to its original state. This approach is helping support long-term sustainable oil and gas development, while protecting future generations of Albertans from experiencing a backlog of sites needing cleanup and from paying these costs.

In Alberta's regulatory system, the government sets the province's policy approach to liability management, and then works with the Alberta Energy Regulator (AER) on its implementation. The government worked with the AER over the past year to operationalize the new framework, which is being done in a phased approach. This approach strikes a balance of driving progress, while also providing producers with the necessary time to implement these significant changes and ensure they are included in their future operations. It also supports refinements to programs and regulatory tools based on early learnings.

Under the new framework's Inventory Reduction Program, mandatory annual closure spend targets for site clean-up that every licensee must adhere to, and incentives for additional voluntary closure work were established. This initiative, which builds on the success of the AER's area-based closure program, will ensure sites get cleaned up while also providing flexibility for licensees to close sites in a cost effective and efficient manner. It will also drive consistent economic activity in the oil field and environmental services sectors for years to come as each year there is a minimum closure spend for industry.

Another part of the Inventory Reduction Program is a formal opt-in mechanism, which will provide a way for landowners, land users, and communities to nominate specific inactive sites for clean up to the regulator. Licensees will have to provide rationale for keeping the well or facility, otherwise it will be required to be cleaned up. Sites nominated through the Site Rehabilitation Program will be considered by the AER and potentially transitioned into the Site Closure Opt-In Program if they meet the eligible requestor and site criteria. The AER published materials and held initial information sessions on the opt-in program in early 2022. Further public engagement is expected later in 2022.

In June 2021, the AER announced the first mandatory closure targets for the oil and gas industry. These came into effect on January 1, 2022. In 2022, industry must spend $422 million on closure activities.

There are many factors that impact development and a company's capability to meet regulatory and liability obligations. The framework's new holistic assessment approach, supported by a Licensee Capability Assessment, will assess the capabilities of oil and gas licensees to meet their obligations prior to receiving regulatory approvals, protecting Albertans from the financial and environmental burden of more inactive or orphaned sites. The improved holistic licensee assessment, will replace the AER's current Liability Management Rating ratio.

The first step toward implementing the holistic licensee assessment occurred in April 2021 when the AER issued an update to Directive 067, Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals, to ensure that licensees are eligible to hold licences, and that they maintain eligibility across the lifecycle of operations. Updates included the ability for AER to collect financial information annually and when required. Collecting this financial information through Directive 067 supports the AER's ability to assess licensee levels of financial distress as part of the holistic approach to assessing a company's ability to manage their regulatory and liability obligations. More information on the Licensee Capability Assessment can be found at: https://www.aer.ca/regulating-development/project-closure/liability-management-programs-and-processes/holistic-assessment-and-licensee-capability-assessment

In December 2021, the AER issued Directive 088, Licensee Life-Cycle Management, introducing the holistic approach. The new approach is a more comprehensive and accurate assessment, taking into account a wider variety of assessment parameters. As part of this, the AER may now consider unpaid municipal taxes and surface lease payments when determining a company's eligibility to hold a license and municipalities and landowners are encouraged to submit statement of concerns at time of application. This improved assessment approach also enables the AER to reach out proactively through the Licensee Management Program before licensees are struggling. This new program provides practical guidance and proactive management for operators, helping them manage their regulatory and liability obligations throughout the energy development life cycle. The AER will work with licensees on mitigations and actions that can help them manage their liabilities, maximize their assets, and maintain their operations.

While this framework will place additional responsibility on industry, it is a fair and appropriate approach, developed after extensive consultation with stakeholders that takes into account the conditions they are facing. The framework is being operationalized in stages to provide oil and gas companies the necessary time to plan for the short and longer terms. The AER is also providing clear information on the changes and new requirements, including publishing manuals and holding information sessions.

Integrated Resource Management

The Government of Alberta approaches natural resource management from an integrated and systems approach, where the cumulative impacts of non-renewable resource development are examined in relation to economic, environmental and social interests. The Integrated Resource Management System (IRMS), Land-use Framework and associated planning processes were designed to provide decision-makers with the information they require to make public policy decisions about natural resource development, including consideration of impacts on communities and the environment.

Energy's mission is to assure sustained prosperity in the interests of Albertans through the stewardship of energy and mineral resource systems, responsible development, and wise use of energy. Included in this are Energy's efforts to inform the Government of Alberta's resource management policies. The role of Energy is to identify risks and opportunities and, through consultation and engagement, ensure land use and resource management policies consider the interests of Albertans as owners of Crown mineral resources and take into account the obligations the Crown has in relation to these resources, such as tenure agreements.

Delivering on these objectives for the province requires reconciling various perspectives to clearly define what is in the public interest. It involves exploring the benefits of continued development, or conserving resources, and understanding and meeting other societal expectations – that is finding balance among economic, social and environmental interests. Conducting analysis, and sharing data and information are the ways in which the ministry ensures the opportunity costs and benefits of land management decisions are well understood and considered in decision-making.

The ministry supports informed decision making by leading the Engaging Communities Practice Group, collaborating with other ministries through IRMS, and building relationships with Indigenous communities, industry participants and stakeholders. In 2021-22, Energy worked collaboratively with cross-ministry partners and external stakeholders at all levels to advance the department's responsible resource development and stewardship objectives.

The examples below are a few highlights:

- **Conserved Land:** In 2021-22, Energy supported Environment and Parks in its efforts to expand Kitaskino Nuwenëné Wildland Park, located south of Wood Buffalo National Park. The expansion, which was completed February 2, 2022, nearly doubled the size of the existing park and added more than 375,000 acres to what was already the largest area of protected boreal forest in the world. The expansion was a collaboration between the Government of Alberta, the Government of Canada, Indigenous communities and industry, with Energy contributing to the socio-economic assessment of the proposal and assisting the Crown mineral rights holders who voluntarily surrendered agreements to support the initiative.

- **Sub-Regional Planning:** On May 29, 2021, Environment and Parks completed public engagement on the draft Bistcho Lake and Cold Lake sub-regional plans. Energy worked alongside IRMS partners throughout the remainder of 2021-22 to revise those plans considering the feedback received from stakeholders and Indigenous peoples. Cold Lake and Bistcho Lake task forces provided recommendations in spring 2021, while Upper Smoky recommendations were received in fall 2021.

  Detailed socio-economic assessments were completed to inform these plans. Both plans are expected to be finalized and begin implementation in 2022.

Energy also provided support to the two caribou sub-regional task forces that were active in 2021-22: Berland and Wandering River. Each task force includes representatives from the local municipalities, Indigenous peoples and communities, the energy sector, the forestry sector, trappers, recreational users, environmental non-government organizations, and other local stakeholders and knowledge holders, and has a mandate to provide recommendations on land use planning at the local scale, including caribou recovery actions. The recommendations from the Berland and Wandering River task forces are expected in spring 2022.

Area Based Closure Program

The AER's area-based closure (ABC) program encouraged companies to work together to close oil and gas infrastructure and sites more efficiently and effectively. 2021 marks the last year of the ABC program as this work shifts to the AER's new Inventory Reduction Program under Directive 088 in 2022. The ABC mapping tool and approach can still be used by licensees and service providers to collaborate and execute on closure work in similar areas, regardless of their closure targets.

For the 2021 calendar year, 66 companies had committed to spend nearly $355.2 million towards closure work. In 2021, ABC participants conducted approximately 65 per cent of all abandonment and reclamation in Alberta. Due to impacts of COVID-19, individual licensee spend targets for 2020 were suspended and licensees were allowed to carry over any reported 2020 closure spend to be credited towards 2021 targets. In 2020 and 2021, ABC participants spent more than $578 million towards the reported closure spend of $853 million. A 2021 ABC Program Highlights report will be published by the AER later this year.

Grant funding received through the Government of Alberta's Site Rehabilitation Program (SRP) did not count towards the voluntary ABC closure spend targets for 2020 and 2021. Where SRP funding did not cover full closure costs of an activity, the portion paid for by licensees could be applied to closure costs in the ABC program.

Orphan Wells

The Orphan Well Association (OWA) plays an important role in the liability management system by cleaning up wells or sites that do not have a viable or responsible owner. Since 2014, the low commodity price environment and other economic challenges led to an unprecedented surge of orphan wells in the OWA's inventory. In response, the Government of Alberta strengthened the OWA's work by making legislative changes that enabled them to better manage these liabilities, and providing and expanding a loan to the OWA to increase the pace of clean up and immediately generate jobs. Additionally, the liability management framework is focused on preventing wells and sites from becoming orphaned in the first place by ensuring that industry addresses their financial and environmental liabilities obligations. These efforts are helping protect the long-term sustainability of the oil and gas industry in Alberta, as well as ensuring these liabilities are managed appropriately.

In 2020-21, enhanced management of orphan sites was enabled through the *Liabilities Management Statutes Amendment Act*, as one part of Alberta's new liability management framework, ensuring a responsible, sustainable oil and gas industry in the province for generations to come. The amendments added authorities for the AER to compel operators to take reasonable care and measures to prevent damage or impairment on oil and gas sites and expanded the mandate of the OWA and enable the association to effectively manage and accelerate the cleanup of orphan sites, helping the AER and OWA protect the value of producing assets and mitigate the risk of an expanding volume of orphan sites. With this enhanced authority and expanded scope the AER has greater ability to take steps to prevent sites from becoming orphaned in the first place, and the OWA has more delegated authority to protect the value of producing assets, protect jobs, protect public safety, and mitigate the risk of a growing inventory of orphan sites. Both the AER and OWA worked to integrate and implement these enhanced authorities into their operations in 2021-22.

Did you know?

The OWA is an independent, non-profit organization that operates under the delegated legal authority of the Alberta Energy Regulator through the Orphan Fund Delegated Administration Regulation. The OWA's mandate is to manage the abandonment and closure of orphan sites – sites that do not have a solvent and responsible owner – to protect people and the environment, and remove the potential risk of unfunded liability. The orphan fund levy is collected from industry players based on licensees' percentage of liability out of the total industry liability. The OWA is led by an independent Board of Directors, which includes industry, regulatory, and government representatives.

The OWA's recent reporting demonstrates how these legislative changes and supports have made a noticeable difference in the province's cleaning up of wells or sites. In 2020-21, the OWA reported that they decommissioned more wells and completed more reclamation projects than any other period in their history; this included:

- Well decommissioning increased 38 per cent to $63.7 million, from $46.2 million the year before.
- Site reclamation increased 78 per cent to $47.8 million, from $26.9 million the year before.
- Facilities decommissioning increased 82 per cent to $22 million, from $12.1 million the year before.
- Pipeline decommissioning increased 53 per cent to $11.3 million, from $7.4 million the year before.
- Working Interest Participant reimbursements and other administration, primarily related to receiverships, remained relatively even at $13.1 million compared to $13.0 million the year before.

The OWA decreased the overall orphan inventory despite receiving a substantial number of new orphan wells, which was a result of the economic downturn. The 2021-22 orphan fund levy was $70 million for industry, helping continue the OWA's momentum in managing and reducing orphan site closure liabilities, while supporting Alberta businesses and communities.

Orphan Well Loan Program

In 2017, the Government of Alberta loaned the OWA $235 million interest-free to accelerate the reclamation of oil and gas well sites that no longer have a responsible owner. In 2020, the loan was expanded by $100 million for a total of $335 million in the Orphan Well Loan Program, creating direct and indirect jobs in the oil field services sector, and allowing for more wells to be decommissioned and additional site assessments for reclamation. The additional loan focused on closure work on lands receiving compensation under section 36 of the *Surface Rights Act*. As of December 31, 2021, the Orphan Well Loan Program has spent the full $335 million, generating approximately 271 direct jobs, and reported the following results from its effort to address the growing inventory of orphaned sites:

- a total of 3,512 wells abandoned,
- 4,282 pipelines decommissioned, and
- 2,303 sites reclaimed.

The work resulting from this loan is in addition to the OWA's ongoing work. The funding received from industry through the annual Orphan Fund Levy is used by the OWA to repay the loan. As of April 2022, the OWA has repaid $91.6 million. The total amount loaned to OWA must be repaid by October 31, 2031.

Annual Wells Decommissioned: Performance Indicator 2.e

Decommissioning is part of the closure process and involves the company removing surface equipment and sealing the well to prevent the well from impacting the environment. This indicator demonstrates the degree to which industry is moving inactive well inventory through the lifecycle towards closure. Increases in insolvent companies and low commodity prices during the COVID-19 pandemic resulted in an unprecedented number of wells and facilities being sent to the OWA.

	2017	2018	2019	2020	2021
Number of wells decommissioned	5,392	5,301	5,994	6,503	11,754
Per cent compared to inactive well population	5.7	5.6	6.0	6.3	11.4

Source: Alberta Energy Regulator[10]

In 2021, 11,754 wells were decommissioned in Alberta. This is an increase of over 80 per cent from 2020. The notable increase in well decommissioning is related to a variety of efforts including the organized and staged implementation of the Liability Management Framework, Directive 088, the continuation of the Area-Based Closure initiative, and the ongoing efforts of the Site Rehabilitation Program, in addition to the increased closure activity underway by the OWA. An increase in year-over-year numbers is a positive signal that operators are addressing their inactive well inventory, which prevents the well from impacting the surrounding environment.

Industry is responsible for these liabilities. Obligations related to the full closure of oil and gas sites are the responsibility of the company (the licensee) licensed by the AER to conduct activity on the site. Alberta's liability management system for upstream oil and gas development maintains the polluter-pays principle to ensure environmental and financial liabilities associated with energy development remain the responsibility of industry. If a licensee goes bankrupt, and there are no related parties to conduct closure activities on their sites, the AER will declare the site an orphan and transfer the responsibility of the site to the OWA. The OWA is funded by industry and was established to address closure requirements for sites held by bankrupt licensees.

Coal Policy

The Government of Alberta rescinded the 1976 Coal Development Policy effective June 1, 2020. In response to concerns raised by Albertans, the policy was reinstated on February 8, 2021, including reinstating the four coal categories that dictated where and how coal leasing, exploration and development could occur. The AER

[10] For more information, see the Performance Measure and Indicator Methodology section of this report on page 86.

was also directed to ensure that all restrictions under the 1976 coal categories were applied, including all restrictions on surface mining in Category 2 lands. In addition, mountaintop removal was prohibited and all future coal exploration on Category 2 lands was prohibited pending widespread engagement on a modern coal policy. Coal lease sales on Category 2 lands were paused.

In accordance with Energy's January 18, 2021 decision to cancel all coal leases issued through the December 15, 2020 public sale, 11 coal leases were compensated and cancelled with a total cost of $80,579.

On March 21, 2021, an independent Coal Policy Committee (CPC) was appointed to lead a comprehensive public engagement to inform the development of a modern coal policy, with deliverables including a report that describes Albertans' perspectives on coal development and a report with recommendations for the management of coal in Alberta.

Alberta produces two types of coal:

- Subbituminous coal is a lower grade of coal that is used domestically to produce electricity. It does not contribute to exports.
- Bituminous coal is a higher grade of coal that is exported overseas for electricity production (thermal coal) or to make steel from iron ore (metallurgical coal).

Leases do not give companies a right to develop. A lease only gives a proponent coal rights in that parcel of land, which they can only produce if they get all the requisite regulatory approvals.

The committee received more than 170 technical submissions and over 1,000 direct emails. Technical submissions and committee updates were shared with Albertans through a custom website developed to support the engagement. The committee also engaged extensively with Albertans and Indigenous communities including:

- more than 70 engagement sessions with Albertans and stakeholders,
- 35 engagement sessions with Indigenous communities and groups, and
- three field tours.

In addition, concurrent to the committee's work, Energy conducted an online survey to gather input from Albertans to inform the coal engagement. Almost 25,000 Albertans from across the province responded to the online survey from March 29 to April 19, 2021. Energy also held five virtual multi-community regional meetings in June 2021, and conducted 13 one-on-one meetings with 12 Indigenous communities and organizations between April and October 2021. Energy engaged with some organizations whose membership consists of leaders from First Nations, such as Tribal organizations, and with the Métis Nation of Alberta Association Provincial Council and the Métis Nation of Alberta Association's Regional Councils as well as other Métis organizations. The results from this engagement helped inform the CPC's recommendations to government.

The committee's engagement report and final report with recommendations were submitted to the Minister of Energy on December 28, 2021 and released to the public on March 4, 2022. The final report provided eight principal recommendations and five associated observations. The Alberta government accepted the findings of the CPC and will look to address its recommendations by updating, strengthening or reinforcing existing regulations and legislation in the future. The reports are available at: https://www.alberta.ca/coal-policy-engagement.aspx

Following the government's acceptance of the committee's recommendations, a Ministerial Order was issued to direct the AER to expand the restrictions on coal exploration and development throughout the Eastern Slopes until further direction has been provided through land-use planning. The order does not extend to activities already in progress for active mines and advanced coal projects, nor does it impact activities related to security or safety, or abandonment and reclamation activities. The order allows abandonment and reclamation activities to resume in Category 2 lands and continue in Category 3 and 4 lands. All existing legislation related to coal activities and Alberta's rigorous regulatory system remain in place. In addition, Energy will not be accepting any new Crown coal lease applications in all land categories within the Eastern Slopes.

The decision to halt new coal activities throughout most of the eastern slopes until new policy direction for coal is provided by new or amended regional and sub-regional plans was made to ensure that coal activities are considered not in isolation but along with all other land use activities and values. It is through this integrated planning that government will effectively manage Alberta's lands and natural resources now and into the future.

Key Objective 2.2

Optimize regulation and oversight of:

- Alberta's energy and mineral resource sector to utilize and develop resource potential in a responsible manner; and
- Alberta's utilities to ensure interests of Albertans are protected.

Alberta Energy Regulator (AER)

The AER is responsible for regulating the life cycle of oil, oil sands, natural gas and coal projects in a manner that protects public safety and the environment. The energy industry fully funds these activities, and in 2021-22, operating costs totalled $205 million. Under the direction of the Government of Alberta, the AER's mandate is expanding to include emerging energy and mineral resource development. In 2021-22, the Government of Alberta provided grants to support costs of $17 million towards the development of these new sectors and associated regulatory frameworks.

Red Tape Reduction at the AER

In 2021-22 the AER revised 37 regulatory instruments – more than it has on any previous year on record. This translated to the removal of 3,225 regulatory requirements in 2021-22 and a total of 5,978 requirements removed, or 15 per cent off the April 1, 2019 baseline of 41,173 (baseline adjusted January 2022). Examples of changes in 2021-22 include:

- Centralized Fluid Storage (Directive 058/Directive 055)
  - These directives were updated to incorporate the storage of large volumes of water, such as produced water, water-based flow back, and oilfield landfill leachate in storage devices for reuse in hydraulic fracturing. In addition, the directives were revised to improve clarity and remove redundant and outdated requirements.
  - Provided a regulatory framework that aligned with the *Red Tape Reduction Act* and resulted in a reduction of 1,150 requirements.
- Directive 050: Drilling Waste Management
  - The changes clarify the requirements, improve regulatory application efficiency, and enable operators to reduce land disturbance from drilling waste management practices.

- Provided a regulatory framework that aligned with the *Red Tape Reduction Act* and resulted in a reduction of 514 requirements.

- Directive 017: Measurement Requirements for Oil and Gas Operations
  - Aligned the well testing requirements for thermal in situ oil sands operators with operating conditions at project sites. This change enables the collection of more-representative well-level production data and provides operators additional flexibility in how they conduct their well testing programs.
  - Provided a regulatory framework that aligned with the *Red Tape Reduction Act* for thermal in situ oil sands operations and resulted in a reduction of 216 requirements.

The red tape reduction mandate has provided an opportunity for the AER to examine its full suite of regulatory instruments.

In completing its work, the AER continued to ensure that the environment was protected, and public safety was maintained. The AER carried out stakeholder and public engagement on any changes that were significant and impactful to stakeholders and rights holders. The AER's efforts have focused on reducing obsolete and redundant requirements to allow regulated operators to be better able to navigate the revised regulatory instruments and understand the requirements.

Indigenous Engagement at the AER

The AER is always seeking to improve how it engages with Indigenous communities and considers their values, interests, and concerns. A foundation of AER's approach is the book "Voices of Understanding" which was co-created in 2017 with an Indigenous Elder and AER staff. The book is a guide to the AER that covers Indigenous worldviews and how to initiate and engage in respectful decision-making processes, and is available at www.aer.ca.

Some of the AER's activities that supported this work in 2021-22 included:

- developing and delivering foundational Indigenous Relations training content for AER staff;
- continuing to create opportunities for First Nations and Metis Settlements to participate in joint compliance inspections on their lands;
- engaging at the executive-level with Indigenous leaders and organizations;
- creating a four-year activity roadmap, as the first step in creating an Indigenous Relations Plan for the AER, providing context, scope and approach for enterprise-wide collaboration;
- completing a communication audit to further develop culturally appropriate materials to support communication with or about Indigenous communities;
- developing an Indigenous engagement guide; and
- hosting an Elder Grandmothers' Circle on National Truth and Reconciliation Day with staff.

This work is intended to support informed decision making, demonstrate AER's responsible approach to energy development, and assist in strengthening relationships and understanding with Indigenous peoples and their interaction with energy development.

AER Industry Performance Program

The industry performance program is an important way that the AER measures, evaluates, and reports on key energy development activities that they regulate. The industry performance program holds companies accountable for their decisions and actions, drives companies to improve their performance, and shares more information with Albertans. The program provides reports in three areas: water use, pipelines, and methane:

- **Water Use** – The water use performance report provides Albertans with information on energy industry water use in Alberta relative to the amount of water available in the province at both a sector level and a company level. Water availability information provides stakeholders and the public with context on how much water is used relative to what is allocated and what is available – this context can help alleviate potential concerns about too much water use by showing that the situation is being regulated adequately and there is enough water available compared to the amounts allocated and used. This report also supports AER efforts to implement the Water Conservation Policy for Upstream Oil and Gas Operators, released in December 2020. The 2021 release of the report can be viewed at: https://www.aer.ca/protecting-what-matters/holding-industry-accountable/industry-performance/water-use-performance
- **Pipelines** – The pipeline performance report provides Albertans with information on the inventory and substances being transported by pipelines in the province, the number of pipeline incidents, and the type of failures and causes of pipeline incidents. The pipeline performance report has enabled the AER to identify issues, gaps, and opportunities on a provincial scale. Where appropriate, these are being incorporated into the draft Pipeline Rules project to improve performance, safety and reduce incidents. The AER evaluates all pipeline failures to understand the cause and to assess compliance with rules, then use what they learn to educate companies, either during pipeline inspections or, for example, through the publication of bulletins. Bulletin 2021-36 was issued in response to an increase in the number of pipeline failures resulting from a form of stress-corrosion cracking on high-temperature carbon steel surface pipelines – this bulletin resulted in an increased awareness of the issue so that companies could proactively identify potential problems and take preventive actions to mitigate the risks. The 2021 release of the report can be viewed at: https://www.aer.ca/protecting-what-matters/holding-industry-accountable/industry-performance/pipeline-performance
- **Methane** – The methane performance report provides Albertans with information on the progress that has been made on reducing methane emissions from upstream oil and gas. The data shows that Alberta's oil and gas methane emissions are estimated to have been reduced by around 34 per cent between 2014 and 2020. AER modelling predicts that Alberta is on track to exceed the Government of Alberta's 45 per cent reduction policy target by 2025. Most of the methane reductions shown occurred prior to AER Directive 060, Upstream Petroleum Industry Flaring, Incinerating, and Venting coming into effect. The reductions can be attributed to improved industry practices, the Alberta Offset System, direct funding programs, and the new methane reduction requirements. The 2021 release of the report can be viewed at: https://www.aer.ca/protecting-what-matters/holding-industry-accountable/industry-performance/methane-performance

Regulatory Compliance: Performance Indicator 2.c

The Alberta Energy Regulator tracks the per cent of inspections that did not result in enforcement actions, and the per cent of inspections in compliance with regulatory requirements, reflecting the AER's ability to achieve its mandate through inspection (prevention) activities. Inspections allow field inspectors to determine if regulatory requirements have been met and provide an opportunity to work directly with companies to bring them back into compliance. Inspections that result in noncompliance are triaged and assessed based on the AER's Integrated Compliance Assurance Framework to determine the best course of action to the correct the noncompliance. Based on the results of the triage assessment an investigation may be warranted. The investigation may result in an enforcement action. An enforcement action is defined as an exercise of statutory power of the regulator in response to a finding of significant noncompliance.

	2017-18	2018-19	2019-20	2020-21	2021-22
Compliant Inspections: Per cent of inspections in compliance with regulatory requirements	76	76	78	79	75

Source: Alberta Energy Regulator[11]

In 2021-22, the AER conducted 7,825 field-based inspections, of which 5,891 resulted in a finding of compliance; meanwhile, in 2020-21 9,048 field-based inspections were conducted, of which 7,176 resulted in a finding of compliance. The subsequent investigations resulted in the issuance of 16 enforcement actions, including five administrative penalties, one prosecution and nine warning letters.

Initial inspections are selected based on an enterprise management approach to defining and applying risk as well as the predetermined level of risk that an activity may pose to health and safety, the environment, resource conservation, and stakeholder confidence in the regulatory process, including public and political influences. Historical operator compliance is a component of the risk-based site selection process.

The AER places higher priority on reactive work, such as releases or complaints. The amount of reactive work can significantly impact the reported result for this indicator because the nature of the work is unplanned and has a high chance of resulting in enforcement action. This kind of work required greater inspector attention and leaves less ability to conduct proactive initial inspections.

AER continues to develop innovative approaches, programs, and processes to manage these liabilities and risks while supporting economic development in the province. The AER's approach to managing liability was built to balance multiple interests: environmental protection, public safety, landowner interests, investment, royalties, jobs, and market volatility.

Pipeline Safety: Performance Indicator 2.d

AER-regulated pipelines transport many different products and are used for a variety of purposes. For example, pipelines can carry raw oilfield production to processing facilities and finished petroleum products to market. The AER regulates companies over the life cycle of their pipelines and uses pipeline incidents as an indicator because of the impacts that incidents can have to the environment, wildlife and the public.

The AER is responsible for ensuring companies in Alberta develop energy resources in a safe and responsible manner. This includes holding companies accountable for their performance and driving companies to improve. The AER assesses all pipeline incidents to understand the cause and to assess compliance. The economy and industry activity affect the number of operating pipelines at any given time which can impact incident rates. Economic stresses and the continued deterioration of financial conditions of industry can result in maintenance budget reductions.

Companies must have a safety and loss management system (SLMS) that outlines corporate policies and processes to manage pipeline operating risks with respect to the public, the environment, the company, its employees, and property. A company's SLMS guides the reliable operation and understanding of a company's pipeline assets. The goal of an SLMS is manage all areas of risk, and to direct all activities associated with the safe operation of pipelines. SLMS enables and requires the implementation of risk management and integrity management plans for all pipeline assets.

The AER conducts construction and operational inspections, to ensure operators are in compliance with pipeline regulations to safely operate and prevent incidents. AER inspections focus on preventative pipeline maintenance programs, leak detection, hydrotechnical and geotechnical programs and inactive pipelines to

[11] For more information, see the Performance Measure and Indicator Methodology section of this report on page 86.

prevent pipeline incidents from occurring. When a pipeline incident does occur, all incidents are reviewed by an inspector to understand the cause and prevent future incidents of a similar manner.

Where appropriate, the AER also helps educate licensees on pipeline integrity issues and how to address them. If the AER identifies that a pipeline is causing or has the potential to cause unacceptable impacts, it can order an immediate suspension of the pipeline until the problems are corrected.

	2017	2018	2019	2020	2021
Number of high-consequence pipeline incidents	26	24	20	16	12

Source: Alberta Energy Regulator[12]

Note: Reviews of past incidents and more accurate information coming available over time has resulted in changes to previously reported numbers and are subject to change as more information is gathered.

Compared with 2020, 2021 saw a decrease of high consequence pipeline incidents from 16 to 12. The total number of incidents remained the same between 2020 and 2021 at 344 incidents. Some factors that influenced these results in 2021 include the following:

- The decrease in total incident number can likely be attributed to industry developing and adopting better pipeline practices, the AER continuing to improve pipeline requirements, inspections and placing a greater focus on educating industry about pipeline safety. It can also be attributed to the overall downturn in the in the oil and gas sector.
- In 2021 the total volume of liquid released was 2,007 cubic metres, 78 per cent lower than in 2020 at 9,272 cubic metres. The AER continues to educate and ensure compliance regarding leak detection programs to prevent large volume spills.
- In 2021, Bulletin 2021-36, issued as a result of an increase in incidents from stress-corrosion cracking on high-temperature carbon steel surface pipelines, we reminded licensees to consider stress corrosion cracking as part of their integrity management programs. The AER provided recommendations for licensees to conduct engineering assessments to determine if their pipelines would be susceptible to failure, to perform inspections on pipelines that may be at risk, evaluate and repair potential defects, review leak detection programs and continue to report leak and rupture incidents.

Dam Safety

Dams are owned by operators in oil sands mining, in situ oil sands, coal mining and oil and gas operations. Under the Water Ministerial Regulation and its associated Dam and Canal Safety Directive, the AER regulates dams operated by energy companies. Together, the Water Ministerial Regulation and directive state all requirements owners must put in place to safely design, construct, operate, manage, and decommission their dams.

Dams are classified based on the potential downstream consequences from a failure. Risk factors considered in a dam's failure consequence classification include downstream population, the environment, the economy, cultural values, and downstream infrastructure. The consequence classes are: low, significant, high, very high, and extreme. Regulatory requirements for a dam are based on its consequence classification. As of 2021, the AER regulates a total of 231 dams, including 122 tailings dams, the majority of which are in the oil sands mining sector. Owners are responsible for the safety of their dams and compliance with regulatory requirements. The AER dam safety program ensures that dam owners are operating their dams in accordance with regulatory requirements, government policy, and industry best practices to protect the public and the environment from dam-related incidents.

[12] For more information, see the Performance Measure and Indicator Methodology section of this report on page 86.

In 2021, the AER released its Dam Safety Program: 2020 Report. This annual report informs the public and industry regarding the dams that Energy regulates and summarizes the activities and outcomes of the dam safety program.

The AER completed all scheduled inspections of dams for 2021. In total, 98 inspections were completed including high- to extreme-consequence dams and all mandated inspections of tailings dams. The AER also completed more than 200 technical reviews of dam safety submissions. Based on the inspections and submission reviews, no critical safety deficiencies were identified or reported to the AER in 2021. A "dam safety incident" is defined by the Dam and Canal Safety Directive as an operation or action at, or in connection with, a dam that has the potential to create a hazardous condition or to be or become a hazard to factors at risk. In 2021, no dam safety incidents were identified by or reported to the AER. For more information, the AER Dam Safety Map provides public information on AER regulated dams: https://extmapviewer.aer.ca/DamSafety/index.html

Fluid Tailings Management

In 2021-22, the AER released the 2020 State of Fluid Tailings Management for Mineable Oil Sands report. The report provides Albertans with information on regional and individual operator fluid tailings volumes relative to fluid tailings profiles and other information related to fluid tailings management for oil sands mining operations. Alberta has eight operating oil sands mines, and by the end of 2019, each site had an approved tailings management plan. Under Directive 085, Fluid Tailings Management for Oil Sands Mining Projects, mine operators must annually submit tailings management reports that show how they are implementing their tailings management plans. This report summarizes the information for the 2019 reporting year and assesses the operators' progress in managing fluid tailings. Operators continue to report improvements in their current tailings treatment technologies and the piloting and development of new technologies.

The Fluid Tailings Management report also has allowed the AER to provide factual information to Albertans on tailings management activities and is used to support decision-making. The 2021 release of the report can be viewed at: https://static.aer.ca/prd/documents/reports/2020-State-Fluid-Tailings-Management-Mineable-OilSands.pdf

Alberta Utilities Commission (AUC)

Finding ways to improve how the province regulates utilities is a central part of what the AUC does. The AUC has been committed to continuous regulatory enhancement, process improvements and streamlining since it was established in 2008. This focus was heightened in 2020-21 due to the organization's goal to modernize its operations, improve its rates proceedings timelines and generally to streamline processes, including reducing red tape to increase investor confidence in Alberta's electricity sector. Additionally, the AUC was compelled through the *Red Tape Reduction Act* to reduce the regulatory requirements found in its 33 rules by one-third by 2023, and to reduce regulatory lag.

Through its oversight of the AUC, the ministry is responsible for setting the legislative and policy framework for the AUC, including to assure safe and reliable supply and delivery of both electricity and natural gas to the province's consumers.

The cost of the AUC's activities in 2021-22 was $28 million, and was fully funded by consumers through levies paid by regulated industry. This was a reduction of 2.2 per cent from 2020-21.

Process Improvement and Streamlining at the AUC

In 2021-22, the AUC's primary strategic pillar was efficiency and limiting regulatory burden, supported by facilitating change in the utilities sector, and ensuring it has the people resources to reach its goals. The AUC also established an aspirational goal to become one of the fastest and most effective regulators in North America. The efficiency and regulatory burden reduction program is intended to:

- reduce the financial and time costs of utility regulation;
- to reduce unnecessary costs for utilities and ratepayers;
- to promote the interests of, and reduce the costs for, Alberta's ratepayers; and
- to underpin a positive investment climate in Alberta to support investment and job creation.

Along with implementing third-party recommendations to improve its rates proceedings, and exploring and piloting mediated settlements, the AUC applied a broad program of streamlining regulatory requirements for both application material and processes. Additionally, the AUC undertook a broad review of its rules to implement third-party recommendations for improvement, to address industry and stakeholder concerns, and to reduce red tape. Some examples of rule reviews and implementation in 2021-22 include:

- Rules of Practice (Rule 001) were amended to uphold the AUC's commitment to adjudicative efficiency, while recognizing that the AUC already has broad authority to assertively case manage its proceedings. The amendments were targeted at codifying standard procedures and the AUC's expectations of parties to promote regulatory efficiency, without altering the AUC's discretion to control its own processes. The amendments support the efficient scoping and scheduling of proceedings through the early establishment of issues lists and process schedules.
- Facilities application requirements (Rule 007) were revised with streamlined and updated information requirements, while integrating Rules Respecting Gas Utility Pipelines (previously, Rule 020).
- The Code of Conduct rule (Rule 030) was repealed to streamline compliance reporting and align the timeframe for compliance audits with the amended Code of Conduct Regulation on a go-forward basis.
- Annual Reporting Requirements of Financial and Operational Results (Rule 005) was amended to streamline the reporting of a utility's annual finances and operations, while ensuring the provision of a sufficient level of detail.
- Review of Commission Decisions (Rule 016) was updated and upgraded to streamline requirements and enhance efficiency.

Additionally, to improve efficiency and reduce regulatory burden and delay, the AUC implemented initiatives in many areas outside its rules, including:

- E-Filing System upgrades completed: three application types have been streamlined to use a trusted-traveller approach for quick processing. The franchise agreement and franchise fee rate riders for both electric and natural gas, as well as independent system operator rule administrative amendment applications, are now eligible for an expedited approval based on input by the applicant into a standard application form.
- Launching and conducting a stakeholder roundtable to chart the AUC's progress on regulatory burden reduction to seek feedback on assertive case management, mediated and negotiated settlements, and AUC performance metrics. The roundtable was used to gauge stakeholder reaction to changes already implemented, and to solicit guidance on where and how further changes and improvements can be implemented. This was a follow-up to a roundtable held in October 2019. Future roundtables will be held as warranted.

The Alberta Utilities Commission has recorded improvements in its regulatory performance and continues to mark further improvements. These improvements are based on a November 2020 third-party benchmarking report comparing the AUC's application and process timelines against similar North American regulators, and include:

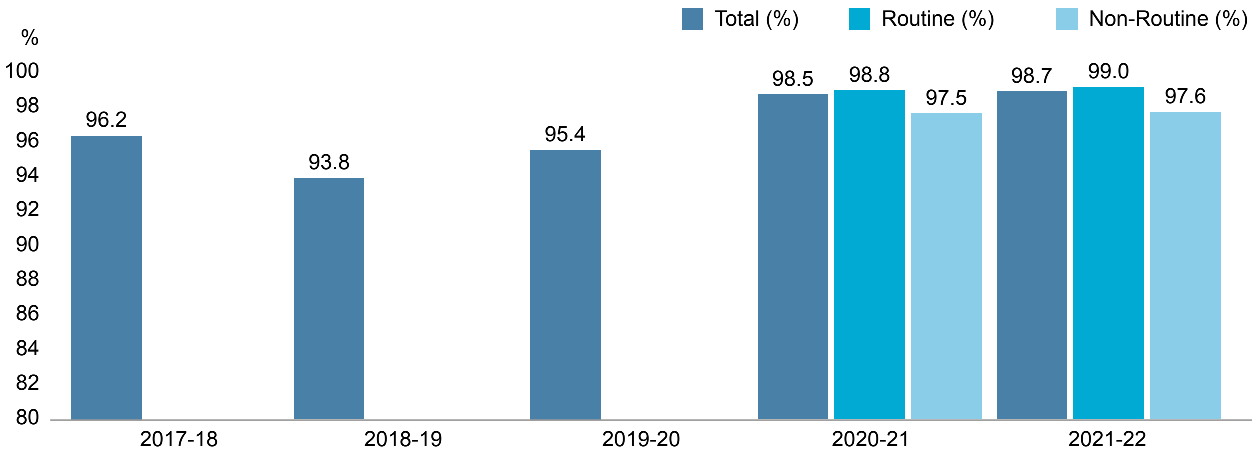
- At March 31, 2022 the AUC had overall decreased the length of time it takes to review applications by 39 per cent. This reduction in full-cycle timeline has been achieved by implementing new tools in the regulatory process including: assertive case management, application streamlining and mediated settlements.
  - Assertive case management, as recommended by third-party experts, had reduced proceeding timelines by 35.1 per cent at March 31, 2022.
  - Application streamlining, which includes the use of checklist applications, delegated authorities and other expedited processes for low-risk applications had reduced timelines by 48.2 per cent as of March 31, 2022.
  - Mediated settlements had reduced application time by 41.4 per cent at March 31, 2022.
- On the facilities' side, continuous process streamlining and a rationalization of application requirements have resulted in facilities application processing times being reduced 19 to 32 per cent.
- In November 2021, one year after implementing third-party recommendations to improve the efficiency and timeliness of AUC rates proceedings, the AUC's large rates cases average time to complete had decreased to 8.7 months from 12.6 months. This is approximately a 30 per cent improvement. Cases started after November 2020 have been reduced to an average of 5.4 months, putting the AUC in the first quartile of performance among peer North American regulators.

As of March 31, 2022, the AUC reported it had accomplished a 48.2 per cent reduction in the regulatory requirements set out in its rules, well ahead of the government's target of a one-third reduction of mandatory requirements by 2023. Reducing regulatory burden has resulted in cost and time savings and other benefits for stakeholders, industry and the AUC. An important consideration of the AUC's efficiency improvements in the regulation of monopoly electricity and natural gas infrastructure, and the adjudication of market cases, is that efficiency must not come at the expense of stakeholder and investor confidence in a fair process, market integrity, or reliably independent and consistent regulation. All are critical to a properly functioning utilities sector. By reducing regulatory requirements, the AUC has simplified the approach existing and new utility companies must take to operate and invest in Alberta's utilities sector. These efficiencies also resulted in reduced costs of regulation. The AUC found one-time savings of $4.1 million in 2021-22, which helped to reduce its administration fee.

Performance Measure 2.a: Timeliness of application processing (Alberta Energy Regulator)

Target: The target for applications meeting their respective turnaround targets for 2021-22 is 100 per cent for routine applications and 95 per cent for non-routine applications.

Percentage of Alberta Energy Regulator applications that met the turnaround targets



Sources: Alberta Energy Regulator[13]

The measure indicates the Alberta Energy Regulator's efficiency in meeting application process timelines. This measure monitors the overall efficiency of the AER's application processing, drives internal performance, and provides certainty and transparency to the public related to AER's turnaround targets.

Overall, in 2021-22, 98.7 per cent of AER applications met turnaround targets. The total number of applications received by the AER increased from 29,597 in 2020-21 to 37,357 in 2021-22. Specifically, the AER met processing targets for 99.0 per cent of routine applications and 97.6 per cent of the non-routine applications. Of the 37,150 applications processed in 2021-22, there were 29,703 routine applications and 7,447 non-routine (higher-risk and more-complex) applications.

This performance can be attributed to ongoing implementation of the AER's Integrated Decision Approach, and improvements to AER systems to automate low risk application types allowing AER staff to focus on applications that pose higher risk. These initiatives will contribute to continued improvement in the turnaround targets for routine and non-routine applications.

2020-21 marked the first year that routine and non-routine applications were tracked and given targets separately. Risks posed to the AER's mandate by energy development are assessed for each application and continually throughout the entire energy development's lifecycle. Contextual factors, such as geographic location, technical characteristics, and operator performance, fluctuate over the energy development life cycle and the AER continuously monitors these through the collection of data from various sources such as reports, inspections, audits and investigations to ensure the risk remains acceptable. All assessments of risk throughout an energy development's life cycle rely on the Government of Alberta's Common Risk Management Framework to ensure that the risk assessment process remains consistent.

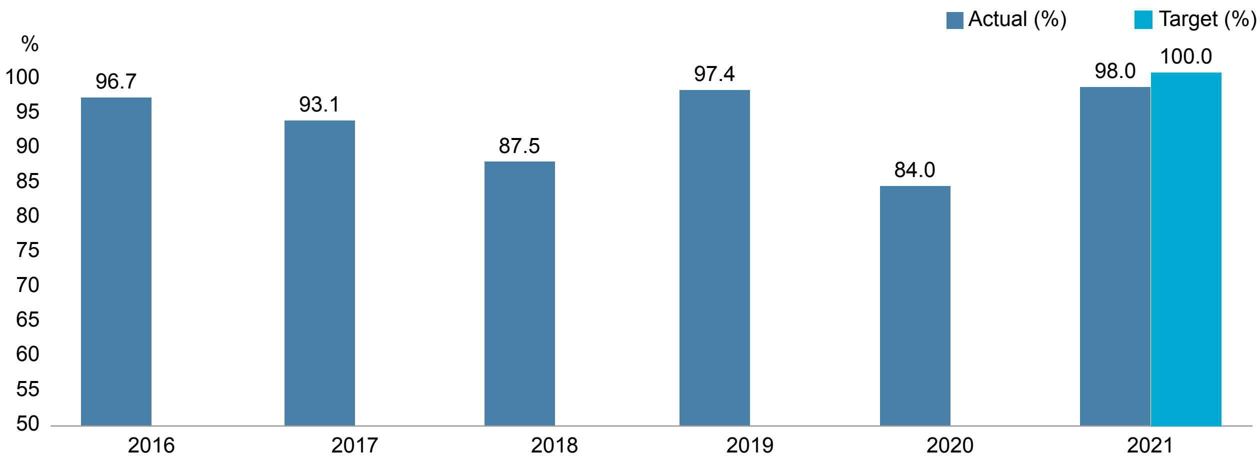
Application turn-around targets for each application process can be found on the AER's website: https://www.aer.ca/regulating-development/project-application/application-processes

[13] For more information, see the Performance Measure and Indicator Methodology section of this report on page 86.

Performance Measure 2.b: Timeliness of the needs and facility applications (Alberta Utilities Commission)

Target: 100 per cent

Percentage of Alberta Utilities Commission needs and facilities applications were determined within 180 days.



Sources: Alberta Utilities Commission[14]

In accordance with standards established in Alberta law, the AUC, when considering an application for an approval, permit or licence in respect of a needs identification document, transmission line or part of a transmission line, must make a decision in a timely manner, and if possible, within 180 days after receipt of a complete application.

For 2021, the AUC met this standard 98 per cent of the time as 67 of 68 decisions were issued within the 180-day timeline. Factors impacted the results include:

- The length of one application was extended as a result of late stakeholder statements of intent to participate delaying the hearing and new evidence being filed after the hearing had already concluded which required additional time for consideration.

[14] For more information, see the Performance Measure and Indicator Methodology section of this report on page 86.

Energy Highlights Table

		2020-21	2021-22
Bitumen	Revenue	$2.01 billion	$11.61 billion
	Bitumen wells drilled (1)	503 (2020)	1,866 (2021)
	Total bitumen production in barrels per day (bbl/d)	2.98 million bpd (2020)	3.26 million bpd (2021)
	Marketable bitumen and synthetic crude oil (SCO) production	2.81 million bpd (2020)	3.07 million bpd (2021)
Conventional Crude Oil	Revenue	$0.47 billion	$1.95 billion
	Average price for West Texas Intermediate	US$42.32/bbl	US$77.03/bbl
	Conventional crude oil production	0.42 million bpd (2020)	0.44 million bpd (2021)
	Pentanes and condensate production	0.33 million bpd (2020)	0.34 million bpd (2021)
	Crude oil wells drilled (1)	1,014 (2020)	2,519 (2021)
Total Crude and Equivalent	Production (conventional, marketable bitumen and SCO, pentanes plus and condensates)	3.56 million bpd (2020)	3.85 million bpd (2021)
	Removals from Alberta (2)	3.47 million bpd (2020)	3.74 million bpd (2021)
	Per cent of total crude oil and equivalent disposition	88% (2020)	88% (2021)
Natural Gas and By-Products	Revenue	$0.47 billion	$2.23 billion
	Average Alberta Gas Reference Price	$2.10/GJ	$3.48/GJ
	Number of conventional natural gas wells drilled (1)	598 (2020)	802 (2021)
	Total marketable natural gas production including coalbed methane	3.45 Tcf (2020)	3.52 Tcf (2021)
	Coalbed methane production	0.17 Tcf (2020)	0.16 Tcf (2021)
	Total natural gas deliveries	4.97 Tcf (2020)	5.25 Tcf (2021)
	* To the United States	34%	33%
	* Within Alberta	39%	39%
	* To rest of Canada	26%	27%
Bonuses and Sales of Crown Leases	Revenue from bonuses and sales of Crown leases	$0.024 billion	$0.23 billion
	Revenue from rentals and fees	$0.12 billion	$0.15 billion
	Average price per hectare (ha) paid at petroleum and natural gas rights sales	$135.63	$328.35
	Petroleum and natural gas hectares sold at auction	152,504.906ha	495,004.820ha
	Average price per hectare paid for oil sands mineral rights	$89.04	$1,075.34
	Oil sands hectares sold at auction	39,192 ha	59,256.78 ha

		2020-21	2021-22
Freehold Mineral Tax	Revenue	$60 million	$107 million
Wells and Licences	Well licences issued (2)	2,848 (2020)	5,543 (2021)
	Industry drilling (3)	2,587 (2020)	5,709 (2021)
Coal	Revenue	$12 million	$10 million
	Established coal reserves (estimate)	33.2 billion tonnes	33.2 billion tonnes
	Raw coal production	18.8 million tonnes (2020)	14.4 million tonnes (2021)
	Total marketable coal deliveries	17.9 million tonnes (2020)	11.1 million tonnes (2021)
	Percentage of total coal deliveries exported out of province	38.2% (2020)	59.5% (2021)
Electricity	Total generation capacity in megawatts (MW)	16,803 (2020)	17,224 (2021)
	Total generation capacity from renewable sources in MW	3,194 (2020)	4,311 (2021)
	Total generation capacity from coal in MW	5,574 (2020)	2,530 (2021)
Metallic and Industrial Minerals	Metallic and Industrial Minerals Royalty Revenues (MINRS)	$856,935	$591,883
	Hectares of mineral permits issued to exploration companies (LAMAS, MIM permits and new application Issued)	0.6 million ha	3.2 million ha
Energy Sector Employment		129,000 (2020)	139,000 (2021)
Energy Sector Investment (4)		$16.7 billion (2020)	Estimated $18.0 billion (2021)

Note: in some cases, numbers may not add up due to rounding.

Notes to table:

(1) Data on wells drilled include both development and exploratory wells.

(2) Results have been retroactively adjusted.

(3) In addition to development and exploratory bitumen, crude oil, and natural gas wells drilled, total industry drilling includes oil sands evaluation wells, and other wells, such as water, waste brine, and miscellaneous wells. Coalbed methane wells are also included, where applicable.

(4) Investment data results for 2020 have been retroactively adjusted to reflect the updates that took place since the publication of the 2020-21 Annual Report.

Performance Measure and Indicator Methodology

Performance Measure 1.a Alberta's Oil Sands Supply Share of Global Oil Consumption

Methodology

This measure is calculated as the annual ratio of the total number of barrels of Alberta oil sands production over the total number of barrels of world oil consumption:

(Annual Barrels of Alberta Oil Sands Production)/(Barrels of World Oil Consumption)

The total for annual barrels of Alberta oil sands production is the sum of total mined and in-situ bitumen production in any given calendar year. Bitumen production data is calculated from Alberta Energy Regulator's (AER) reports. Global oil consumption data is based on the Oil Market Report, published by the International Energy Agency.

Sources

Alberta Energy Regulator; International Energy Agency

Performance Indicator 1.b Alberta Production

Methodology

Alberta's crude oil and equivalent production portion of the indicator consists of: Volume (millions of barrels/day)

The indicator reports the volume of Alberta's annual crude oil and equivalent production. Alberta's crude oil and equivalent production consists of conventional crude oil production, marketable oil sands production (which consists of non-upgraded bitumen and upgraded bitumen), and condensate and pentanes plus. All data for this component of the indicator is taken from the AER reports. The units may be changed in the Annual Report, depending on how the results are reported. Alberta's Energy Resource Sector section in the Annual Report provides an overview of crude oil and equivalent production, calculated from the AER reports.

The total marketable natural gas production portion of the indicator consists of: Volume (billion cubic feet/day)

The indicator reports the volume of Alberta's marketable natural gas production. All data for the indicator is taken from the AER reports. Alberta's Energy Resource Sector section provides an overview of marketable natural gas production in Alberta. The units may be adjusted, as required.

There have been changes to how this indicator is reported. Previously, both crude oil and equivalent, and marketable natural gas components of the indicator also reported Alberta production as a percentage of Canadian production, as well as the total percentages of oil and gas leaving the province. To align the present Annual Report with the 2021-24 Business Plan, the components were changed to reflect production volumes only. The present Annual Report also includes an adjustment that was made in the 2022-25 Business Plan, as the source for both the crude oil and equivalent, and marketable natural gas production components of the indicator was changed from the Canadian Energy Regulator to the AER. This change in reporting is consistent with the general statistical reporting at Alberta Energy. The Annual Report reports the shares of Alberta oil and gas production in the Canadian context, and total percentages of oil and gas leaving the province, but this is reported as supplemental information.

Source

Alberta Energy Regulator

Performance Indicator 1.c Alberta Investment

The Upstream portion of the indicator consists of: CAD$ billions.

This portion of the indicator reports investment in Alberta's Mining, Quarrying, and Oil and Gas Extraction sector. The data for the indicator is taken from Statistics Canada. Data is reported on a calendar year basis.

The Downstream portion of the indicator consists of: CAD$ billions.

In addition to upstream investment, the energy industry generates significant downstream activity; this portion of the indicator focuses on the investment impacts of the downstream activity. The indicator is explicitly focused on petroleum and coal product manufacturing, and chemical manufacturing; this allows for the coverage of petroleum refining and petrochemical manufacturing activity, among other downstream activities. The Downstream portion of the indicator can be treated as complementary to the Upstream portion. There is no overlap between the data reported by both portions of the indicator, as they are based on different industrial categories.

Just like investment data in the Upstream portion, data for the Downstream portion of the indicator is taken from Statistics Canada. Data is reported on a calendar year basis. In addition to actual results, both the Upstream and Downstream components of the present indicator also report the most current preliminary actual results, to enhance the timeliness of data presentation. The preliminary actual results will be revised once the actual results become available.

Previously, the indicator also reported both the upstream and downstream investment in Alberta in the Canadian context. Alberta investment as a percentage of Canadian investment was reported for the upstream and downstream components. In the 2021-24 Business Plan, the indicator was adjusted. The formal portion of the indicator only includes the investment amounts, in Canadian dollars, in the upstream and downstream portions. While the Annual Report still reports the shares of Canadian investment, these shares are included as supplemental information, as opposed to being a formal part of the indicator.

Source

Statistics Canada

Performance Measure 2.a Timeliness of Application Processing (Alberta Energy Regulator)

Methodology

Data used to populate this measure come from the following data sources:

- Integrated Application Registry (IAR) – IAR is the application workflow system used for most applications regulated under the *Oil & Gas Conservation Act*, *Oil Sands Conservation Act*, *Coal Conservation Act*, and *Pipeline Act*.
- PLA AppTracker – The PLA AppTracker is a Microsoft Access solution used to track applications submitted under the *Public Lands Act*.

- AppTracker – The AppTracker is a Microsoft Access solution used to track applications submitted under the *Environmental Protection and Enhancement Act, the Water Act*, and applications that are not captured in IAR. OneStop is the new application workflow system being developed and implemented to eventually encompass all AER applications. Pipeline applications, *Water Act* approvals, land use applications, new well applications, and reclamation certificates are processed through OneStop. Well amendment applications are scheduled to be processed in OneStop in third quarter 2020-21 fiscal year. All data from OneStop with the exception of reclamation certificates has been incorporated into this metric. It is expected that reclamation certificate data will be added in the 2020-21 fiscal year.
- Structured Review Tool (SRT): The SRT provides a consistent and focused way to review elements of submissions that have been identified as high risk or uncertain.

Historical results may shift slightly over time due to the following factors:

- applications not being counted as either meeting or exceeding target until a decision has been issued,
- timing of the data extraction (i.e. incomplete vs a complete data set),
- back dated applications being completed and included in annual values, and
- correcting any manually entered data errors.

Source

Alberta Energy Regulator

Performance Measure 2.b Timeliness of the needs and facility applications (Alberta Utilities Commission)

Methodology

The statutory deadline for issuing decision reports is 180 days, with possible 90-day extensions under certain circumstances. These statutory timelines begin on the date when the Alberta Utilities Commission deems the application complete. The status of applications is tracked daily.

Source

Alberta Utilities Commission

Performance Indicator 2.c Regulatory Compliance (Alberta Energy Regulator)

Methodology

The data source is the Field Inspection System (FIS) system. A .SQL script pulls the results for this indicator; the data is deemed to be reliable and credible as a result of data integrity procedures and required manual review of inspection records.

AER field inspectors inspect the activities of the in-situ and conventional oil and gas, pipeline, and coal and oil sands mining industries. The inspection findings and outcome are recorded in the FIS system database. Geophysical inspections are not included in the FIS system due to legislated confidentiality requirements, and therefore are not included in these results.

The field inspections for this indicator include the following activities: drilling operations, gas facilities, oil facilities, pipelines, well servicing operations, drilling waste, well sites, coal mines, mineable oil sands and waste management facilities. The inspection count is based on initial inspections and re-inspections.

Initial inspections are selected based on an enterprise management approach to defining and applying risk as well as the predetermined level of risk that an activity may pose to health and safety, the environment, resource conservation, and stakeholder confidence in the regulatory process, including public and political influences. Historical operator compliance is a component of the risk-based site selection process. Re-inspection may be needed subsequent to the initial inspection and is at the discretion of the inspector.

The list of enforcement action types for all years has been updated to include warning letters, orders, section 106 and prosecutions. Previously, non-compliances with suspensions and administrative sanctions were included, however they have now been removed as they can occur without an investigation, therefore they are not truly a type of field enforcement action.

2020-21 data were retrieved on April 14, 2021. The reported numbers include closed, amended and reconsidered enforcement decisions.

Source

Alberta Energy Regulator

Performance Indicator 2.d Pipeline Safety (Alberta Energy Regulator)

Methodology

A reportable pipeline incident under the AER's jurisdiction is any pipeline release, break or contact damage (regardless if there is a release) (Section 35 of the *Pipeline Act*). Incident information is entered into the AER's FIS database by AER inspectors. The incident information is used to assign a consequence rating by the AER to indicate the severity of the incident. High consequence pipeline incidents are those that could have significant impacts to the public, wildlife, or the environment, or that involve the release of a substance that affects a large area or water body. Records are reviewed for accuracy and consistency.

Source

Alberta Energy Regulator

Performance Indicator 2.e Annual Wells Decommissioned (Alberta Energy Regulator)

Methodology

An Inactive Well List count is published daily on the AER website. To facilitate year over year comparisons, historical data is captured annually as of December 31 of each year. The following formula is used:

Per cent of wells decommissioned and left in a safe and secure condition = Annual Wells Decommissioned divided by (Inactive Well Inventory +Annual Wells Decommissioned)

Inactive Well Status is based on data retrieved from Petrinex. Wells are deemed inactive as per Directive 013 as follows:

- Critical sour wells (perforated or not) that have not reported any type of volumetric activity (production, injection or disposal) for six consecutive months.

- All other wells that have not reported volumetric activity (production, injection or disposal) for 12 consecutive months.

Well Decommissioning is based on surface abandonments for a well. A well may be decommissioned multiple times over its life (e.g., abandoned, re-entered and then abandoned again). A query is used to retrieve only the most recent record for a given surface abandonment date. Note that if a well has multiple abandonment records in multiple years, these are counted within each year.

Data is submitted by industry operators. Specifically, production data submitted to Petrinex and well license abandonments submitted via the Digital Data Submission. The reliability of the data is contingent on industry operators providing the AER with up-to-date information.

Source

Alberta Energy Regulator

Financial Information

Table of Contents

Reporting Entity and Method Consolidation

The financial information is prepared in accordance with government's stated accounting policies, which are based on Canadian Public Sector Accounting Standards.

The reporting entity is the ministry for which the Minister of Energy is accountable. The accounts of the ministry, which includes the department and the entities making up the ministry, are consolidated using the line-by-line method, except those designated as government business enterprises (GBEs).

Under this method, accounting policies of the consolidated entities are adjusted to conform to those of the government and the results of each line item in their financial statements (revenue, expense, assets, and liabilities) are included in government's results. Revenue and expense, capital, investing and financing transactions and related asset and liability balances between the consolidated entities have been eliminated.

GBEs are accounted for on a modified equity basis, with the equity being computed in accordance with the accounting standards applicable to those entities. Under the modified equity method, the accounting policies of the GBEs are not adjusted to conform to those of the government. Inter-entity revenue and expense transactions and related asset and liability balances are not eliminated.

A list of the individual entities making up the ministry are shown on the "Management's Responsibility for Reporting" statement included in this annual report.

Ministry Financial Highlights

Statement of Revenues and Expenses (unaudited)

End of the year March 31, 2022

	2022		2021	Change from	
	Budget	Actual	Actual	Budget	2021 Actual
		(in thousands)			
Revenues					
Non-Renewable Resource Revenue					
Bitumen Royalty	$ 1,482,000	$ 11,605,218	$ 2,005,884	$ 10,123,218	$ 9,599,334
Natural Gas and By-Products Royalty	467,000	2,226,301	465,162	1,759,301	1,761,139
Crude Oil Royalty	627,000	1,946,938	465,970	1,319,938	1,480,968
Bonuses and Sales of Crown Leases	151,000	227,937	23,731	76,937	204,206
Rentals and Fees	118,000	152,772	118,094	34,772	34,678
Coal Royalty	10,000	10,383	12,032	383	(1,649)
Total Non-Renewable Resource Revenue	2,855,000	16,169,549	3,090,873	13,314,549	13,078,676
Freehold Mineral Rights Tax	67,000	107,251	59,818	40,251	47,433
Transfers from Government of Canada	450,000	298,356	127,954	(151,644)	170,402
Industry Levies and Licenses	313,714	315,379	212,780	1,665	102,599
Other Revenue	1,972	54,208	4,704	52,236	49,504
Net Income (Loss) from Government Business Enterprises					
Alberta Petroleum Marketing Commission	(570,159)	2,059,485	(1,854,102)	2,629,644	3,913,587
The Balancing Pool	107,445	95,984	(112,770)	(11,461)	208,754
Ministry total revenues	3,224,972	19,100,212	1,529,257	15,875,240	17,570,955
Inter-ministry consolidation adjustments	-	(358)	(212)	(358)	(146)
Ministry total revenues	3,224,972	19,099,854	1,529,045	15,874,882	17,570,809
Expenses - Directly Incurred					
Ministry Support Services	7,216	5,555	5,373	(1,661)	182
Resource Development and Management	79,065	48,818	58,687	(30,247)	(9,869)
Cost of Selling Oil	72,000	233,705	46,308	161,705	187,397
Climate Change	32,414	23,341	20,598	(9,073)	2,743
Carbon Capture and Storage	58,934	43,665	126,575	(15,269)	(82,910)
Market Access	976,000	866,454	442,530	(109,546)	423,924
Economic Recovery Program	477,350	300,237	129,640	(177,113)	170,597
Utility Consumer Support	-	295,548	-	295,548	295,548
Energy Regulation	208,269	221,629	203,753	13,360	17,876
Utilities Regulation	31,477	27,966	30,479	(3,511)	(2,513)
Orphan Well Abandonment	74,000	77,824	65,698	3,824	12,126
Ministry total expenses	2,016,725	2,144,742	1,129,641	128,017	1,015,101
Inter-ministry consolidation adjustments	-	(160)	(441)	(160)	281
Adjusted ministry total expenses	2,016,725	2,144,582	1,129,200	127,857	1,015,382
Annual Surplus before inter-ministry consolidation adjustments	1,208,247	16,955,470	399,616	15,747,223	16,555,854
Inter-ministry consolidation adjustments	-	(198)	229	(198)	(427)
Adjusted annual surplus	$ 1,208,247	$ 16,955,272	$ 399,845	$ 15,747,025	$ 16,555,427

Revenue and Expense Highlights

Revenues

Energy's 2021-22 total revenues of $19.10 billion consist of the following:

- **Non-Renewable Resource** revenues totalling $16.17 billion was $13.31 billion higher than budgeted primarily due to bitumen royalties $10.12 billion higher than budgeted. The increase was primarily due to higher than forecasted West Texas Intermediate (WTI) and Western Canadian Select (WCS) prices.
- **Freehold Mineral Rights Tax** revenues totalled $107 million and relate to annual taxes on private freehold mineral rights and was $40 million higher than budget. This was caused mainly by a higher unit value for oil.
- **Industry levies and licences** totalled $315 million and relate to levies and licences collected from industry by the Alberta Energy Regulator (AER) and the Alberta Utilities Commission. Industry levies and licences were $2 million over budget mainly due to anticipated short falls in revenue as a result of COVID-19 and a downturn in the industry.
- **Transfers from Government of Canada** totalling $298 million in revenues recognized to offset grant expenses incurred for the Site Rehabilitation Program. Of the $1 billion received in 2020-21 from the federal government's COVID-19 Economic Response Plan, $574 million has been recognized as deferred contributions to be expended in future years of the program.
- **Net Income from Government Business Enterprises** totalling $2.16 billion were higher than budget by $2.62 billion mainly due to higher than anticipated income from the Alberta Petroleum Marketing Commission resulting in a variance of $2.6 billion primarily from the decrease of the Sturgeon Refinery processing agreement onerous contract provision.
- **Other revenue** totalling $54 million was $52 million higher than budgeted primarily due to the recognition of proceeds from the Renewable Electricity Program in revenue for the current year.

Expenses

Energy's 2021-22 operating expenditures totalled $2.14 billion with an operating deficit of $128 million compared to budget and increased spending of $1.02 billion compared to 2020-21. This was primarily related to:

- **Market Access** – This program reflects costs spent on the Crude by Rail program. In 2021-22, the Crude by Rail program incurred costs of $866 million, $110 million lower than budgeted. This was primarily due to savings achieved in negotiating the final contract terminations, which were completed in 2021-22.
- **Economic Recovery Program** – The costs included in this program relate to the Site Rehabilitation Program (SRP). In 2021-22, the ministry incurred $300 million in operating and grant expenditures to support this program, which were $177 million lower than budgeted. This was a result of delays in program intakes due to impacts from COVID-19 and labour shortages.

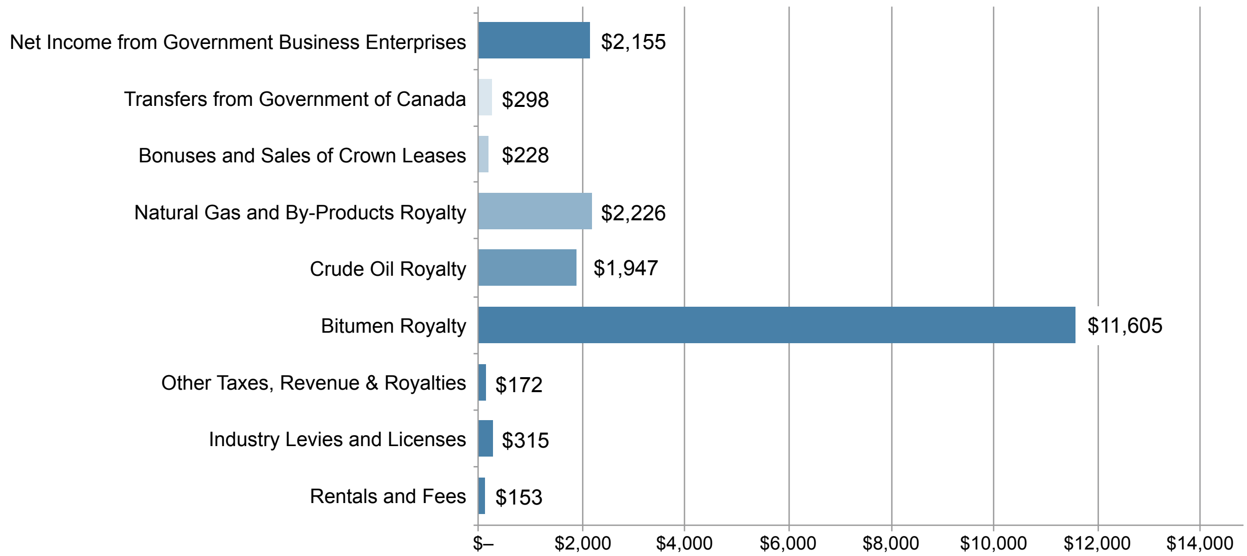
  The year-over-year increase of $171 million is due primarily to a lower spend in 2020-21 based on the program timing as the SRP was launched in May 2020.
- **Utility Consumer Support** – This program reflects unbudgeted expenses related to the Electricity Rebate Program announced in March 2022. The program will provide electricity rebates of $50 per month for three consecutive months, for a total rebate of $150, for customers whose electricity use is under 250 MW hours per year.

- **Cost of Selling Oil** – This program includes the costs incurred by the Alberta Petroleum Marketing Commission to sell crude oil royalties on behalf of the ministry. These costs were $162 million higher than budget and $187 million higher than previous year actuals due primarily to a rebound in market prices that were suppressed due to the oil price war and economic downturn that occurred in 2020.
- **Carbon Capture and Storage** – This program supports two Carbon Capture and Storage projects in Alberta: the Shell Quest Project and the Alberta Carbon Trunk Line project (ACTL). Due to lower than budgeted payments for CO2 injection volumes, this program spent $15 million less than budget. The year over year decrease in spending of $83 million was due to the timing of payments related to milestone achievements for the ACTL project, which achieved commercial operation in 2020-21.
- **Energy Regulation** – This represents the costs incurred by the AER to support the regulation of Alberta's energy resources. The AER's activities are fully funded by industry levies. In 2021-22, the AER spent $13 million more than budget and $18 million more than 2020-21. This is primarily due to expenses incurred to support the province's Mineral Strategy program, which was assigned to the AER subsequent to the approval of Budget 2021.
- **Resource Development and Management** – Resource development and management captures the costs incurred by the ministry to support various energy policy and operations activities. These activities have an approved budget of $79 million.
  - Energy Policy (Budget: $35 million) – The ministry develops strategic policies to support Alberta's energy and mineral resource markets and electricity systems. The ministry incurred a surplus of $4 million primarily due to lower than anticipated labour costs resulting from attrition, delays in hiring and a reduction in discretionary spending.
  - Energy Operations (Budget: $17 million) – The ministry oversees Alberta's energy, mines and minerals royalty and tenure systems (which includes the calculation and collection of revenues from energy and mineral royalties, mineral rights leases, and bonuses and rent). The ministry experienced a $4 million surplus primarily due to a reduction in allowances booked for doubtful accounts, lower than anticipated labour costs due to attrition, delays in hiring, and a reduction in discretionary spending.
  - Industry Advocacy (Budget: $27 million) – The ministry ensures misinformation about Alberta's energy industry is addressed, which includes activities associated with the Canadian Energy Centre. This program incurred an actual expense of $5 million, which was $22 million under budget mainly due to government's adherence to cost control measures.
- **Climate Change** – The costs included in this program relate to the Renewable Electricity Program and the annual payments for the Coal Phase-Out Agreements. The ministry incurred a $9 million surplus due primarily to lower expense related to the Renewable Electricity Program as a result of higher than anticipated market electricity prices. The year over year increase of $3 million is primarily associated with higher accretion expense for the Coal Phase Out agreements incurred in 2020-21 due to cost settlements.

Breakdown of Revenues (unaudited)

The following information presents detailed revenues of the ministry. The objective of detailed revenues disclosure is to provide information that is useful in understanding and assessing the financial impact of government's revenue raising and for enhancing legislative control.

2022 Actual
(in millions)



Non-Renewable Resource Revenue

Revenue ($ Millions)	2021-22 Budget	2021-22 Actual
Bitumen Royalty	$1,482	$11,605
Natural Gas & By-Products	467	2,226
Crude Oil Royalty	627	1,947
Bonus and Sales of Crown Leases	151	228
Rentals and Fees	118	153
Coal Royalty	10	10
Non-Renewable Resource Revenue	$2,855	$16,170

Source: Government of Alberta

- **Bitumen** royalties remained the largest portion of resource royalty revenue. In 2021-22, bitumen revenue totaled $11.61 billion. Actual bitumen royalties were about 683 per cent, or $10.12 billion higher than budgeted. This variance is mainly due to the significantly higher WTI and WCS prices for the fiscal year.
- **Natural gas and by-products** brought in $2.23 billion, and were $1.76 billion or 377 per cent above the budgeted amount. The favorable variance is attributable to higher than budgeted WTI and Alberta Natural Gas Reference Price.
- **Conventional crude oil** royalties contributed $1.95 billion. Conventional crude oil royalties were $1.32 billion, or 211 per cent higher than the budgeted amount, mainly due to the significantly higher than forecast WTI prices and higher production for the fiscal year.
- In 2021-22, **Bonuses and Sales of Crown Leases** totaled $228 million, which was $77 million or 51 per cent higher than the budgeted amount mainly due to an increase in average price per hectare.

- Revenue from **Rentals and Fees** was $153 million in 2021-22, higher than the budgeted revenue by $35 million, or 29 per cent. Rentals and fees revenue is tied to land sales in the current and the previous years. In that, a lease or license holder has to pay rent every year and are also required to pay upfront the first year of rent in full when their bid wins the bonus auction. Revenue was higher due to higher escalating rent charges for oil sands rental.
- In 2021-22, the ministry recognized $298 million in **Transfers from Government of Canada** to offset grant expenses incurred for the Site Rehabilitation Program, which was $152 million or 34 per cent lower than the budgeted amount due to delays in program intakes resulting from COVID-19 and labour shortages.
- Included in **Other Taxes, Revenue & Royalties** totaling $172 million is revenue from coal royalties of $10 million, which was equal to the amount budgeted. Also included is freehold mineral rights tax revenue, which totalled $107 million and was $40 million higher than budget. This was caused mainly by a higher unit value for oil.

Royalty Program Adjustments

The ministry has a number of royalty programs under the Alberta Royalty Framework, which ceased accepting new participants as of 2017 and will be phased out once their regulations expire. The programs to be phased out include the Natural Gas Deep Drilling Program, Emerging Resources and Technologies Initiative, Incremental Ethane Extraction Program and the Enhanced Oil Recovery Program. The ministry will continue to monitor and report on the progress of all royalty programs until they have officially expired.

In 2021-22, Non-Renewable Resource Revenues are reported net of the following royalty program adjustments:

	2022	2021
	(in thousands)	
Royalty Program:		
Natural Gas Deep Drilling Program	$ 94,122	$ 142,838
Shale Gas	99	7,260
Horizontal Oil	1,611	531
Incremental Ethane Extraction Program	1,051	11,331
Enhanced Oil Recovery Program	21,020	5,201
Proprietary Waiver	5	2,497
Horizontal Gas	417	496
Otherwise Flared Solution Gas	23	115
Coalbed Methane	0	4
Total Royalty Program Adjustment	$ 118,348	$ 170,273

Revenue from Other Government Organizations

Industry levies and licences totaled $315 million, which primarily includes $288 million from the Alberta Energy Regulator (AER) and $27 million from the Alberta Utilities Commission (AUC). Industry levies and licenses were $2 million over budget mainly due to levy approvals made in the first quarter of 2021-22 for anticipated short falls in other revenue areas as a result of COVID-19 and a downturn in the industry.

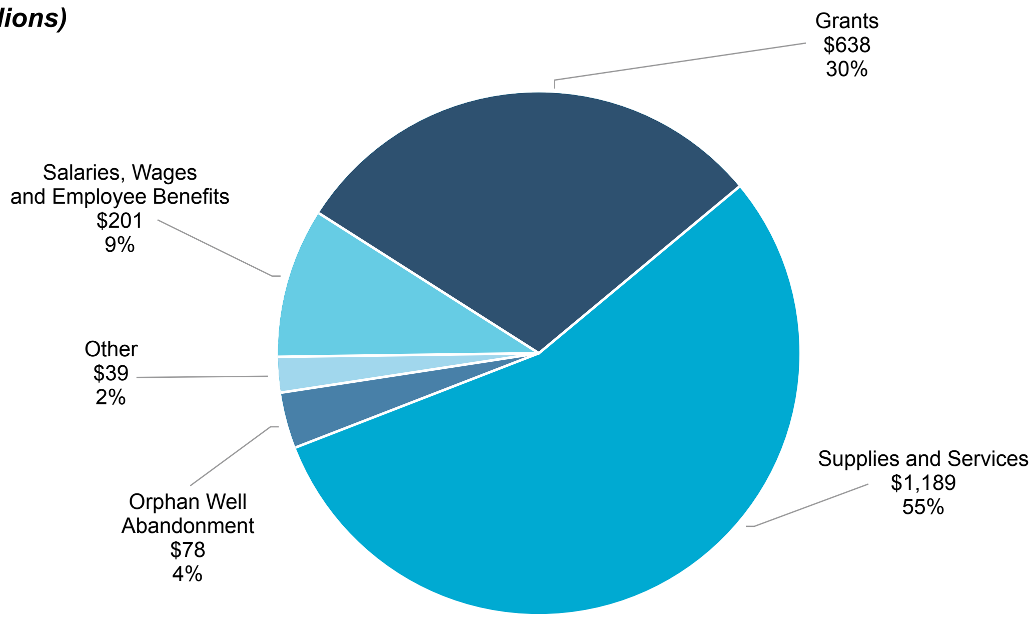
Net income / (loss) from Government Business Enterprises

- Net income from Government Business Enterprises is comprised of net income from the Balancing Pool (BP) of $96 million and net income from the Alberta Petroleum and Marketing Commission (AMPC) of $2.06 billion.
- The BP's net income of $96 million in 2021-22 decreased the accumulated deficit from an opening balance of $780 million to $684 million as of March 31, 2022. Lower than budgeted net income of $11 million was attributed to Payments in Lieu of Tax refunds issued to a provider for losses incurred for tax purposes.
- The APMC's net income of $2.06 billion in 2021-22 decreased the accumulated deficit from an opening balance of $4.64 billion to $2.58 billion as of March 31, 2022. The net income was driven primarily by the decrease of Sturgeon Refinery processing agreement onerous contract provision.

Expenses – Directly Incurred Detailed by Object (unaudited)

The following information presents expenses of the ministry that were directly incurred by object. The objective of disclosure of expenses by object is to provide information that is useful in evaluating the economic impact of government acquiring or consuming various types of resources.

2021-22 Actual
(in millions)



- **Supplies and Services**, which represented 55 per cent of total operating expense, were the largest component of the ministry's operating expense ($1,189 million). This consisted primarily of the costs related to the Crude by Rail program ($866 million) and costs of selling oil ($234 million). The remainder primarily consisted of ongoing supply requirements for the ministry (i.e., contracts and contract services, materials and supplies, and shared services provided by the Ministry of Service Alberta).
- **Grants**, which represented 30 per cent of total operating expense, were the second largest component of the ministry's operating expense ($638 million), primarily consisted of payments related to the Site Rehabilitation Program ($298 million), Electricity Rebate Program ($296 million) and Carbon Capture and Storage projects ($44 million).
- **Salaries, Wages and Employee Benefits**, which represented 9 per cent of total operating expense ($201 million), and primarily support the collection of revenue, development of resource policy, regulatory work provided by the AER and AUC, and the overall support and management of ministry operations.
- **Orphan Well Abandonment** expenses, totaling $78 million (4 per cent), relate to the remittance of levies collected on behalf of the Orphan Well Association for the reclamation of abandoned wells, facilities and pipelines that are licensed to defunct licensees, as delegated by the AER.
- **Other expenses**, totaling $39 million (2 per cent), primarily consisted of accretion expenses related to the off coal agreements ($23 million) and amortization of tangible capital assets ($16 million).

Supplemental Financial Information

Liabilities

Gas Royalty Deposits

- The ministry requires that natural gas producers maintain a deposit, which in most cases is equal to one-sixth of the prior calendar year's royalties multiplied by the ratio of the long-term gas reference price on the date which the recalculation of the gas deposits is determined to the prior calendar year average gas reference price. The ministry does not pay interest on the deposits. As of March 31, 2022, the Ministry of Energy has gas royalty deposits of $129 million.

Coal Phase-Out Agreements

- On November 24, 2016, the Minister of Energy, on behalf of the Province of Alberta, reached agreements with three coal-fired generators to cease operations on or before December 31, 2030. The coal-fired generation plants covered under agreements include: Sheerness 1 and 2; Genesee 1, 2, and 3; and Keephills 3.
- The Ministry of Energy will make payments totaling $97 million annually to the three generators. The first payment was made July 31, 2017 and payments will continue for the next 10 years. In return, the coal-fired plants named above will meet a number of conditions on an annual basis and will cease operations in the coal-fired electricity generation plants on or before December 31, 2030. These conditions are specific to each party, generally requiring each of the coal-fired generator owners to spend a minimum specified amount in the communities in which the plants were located, along with future specified value of investment and investment related activities in Alberta with respect to the electricity business.
- The present value of the remaining 9 payments, discounted at 3 per cent (representing the government's average 10-year bond rate at time of negotiations), is $864 million. The amount of the draw down over the next five years and thereafter are as follows:

		(in thousands)	
	Annual Payment	**Principal**	**Interest**
2022-23	96,024	74,845	21,179
2023-24	96,024	77,117	18,907
2024-25	96,024	79,457	16,567
2025-26	96,024	81,869	14,155
2026-27	96,024	84,354	11,670
Thereafter	384,094	363,811	20,283
	$ 864,214	$ 761,453	$ 102,761

Financial Statements of Other Reporting Entities

Table of Contents

Alberta Energy Regulator
Consolidated Financial Statements
For the Year Ended March 31, 2022

Table of Contents

Auditor General OF ALBERTA

Independent Auditor's Report

To the Board of Directors of the Alberta Energy Regulator

Report on the Consolidated Financial Statements

Opinion

I have audited the consolidated financial statements of the Alberta Energy Regulator (the Group), which comprise the consolidated statement of financial position as at March 31, 2022, and the consolidated statements of operations, change in net financial assets (net debt), and cash flows for the year then ended, and notes to the consolidated financial statements, including a summary of significant accounting policies.

In my opinion, the accompanying consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Group as at March 31, 2022, and the results of its operations, its change from net debt to net financial assets, and its cash flows for the year then ended in accordance with Canadian public sector accounting standards.

Basis for opinion

I conducted my audit in accordance with Canadian generally accepted auditing standards. My responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Consolidated Financial Statements* section of my report. I am independent of the Group in accordance with the ethical requirements that are relevant to my audit of the consolidated financial statements in Canada, and I have fulfilled my other ethical responsibilities in accordance with these requirements. I believe that the audit evidence I have obtained is sufficient and appropriate to provide a basis for my opinion.

Other information

Management is responsible for the other information. The other information comprises the information included in the *Annual Report*, but does not include the consolidated financial statements and my auditor's report thereon. The *Annual Report* is expected to be made available to me after the date of this auditor's report.

My opinion on the consolidated financial statements does not cover the other information and I do not express any form of assurance conclusion thereon.

In connection with my audit of the consolidated financial statements, my responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or my knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work I will perform on this other information, I conclude that there is a material misstatement of this other information, I am required to communicate the matter to those charged with governance.

Responsibilities of management and those charged with governance for the consolidated financial statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with Canadian public sector accounting standards, and for such internal control as management determines is necessary to enable the preparation of the consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing the Group's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless an intention exists to liquidate or to cease operations, or there is no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Group's financial reporting process.

Auditor's responsibilities for the audit of the consolidated financial statements

My objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes my opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, I exercise professional judgment and maintain professional skepticism throughout the audit. I also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for my opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Group's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Group's ability to continue as a going concern. If I conclude that a material uncertainty exists, I am required to draw attention in my auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify my opinion. My conclusions are based on the audit evidence obtained up to the date of my auditor's report. However, future events or conditions may cause the Group to cease to continue as a going concern.-
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Group to express an opinion on the consolidated financial statements. I am responsible for the direction, supervision and performance of the group audit. I remain solely responsible for my audit opinion.

I communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that I identify during my audit.

[Original signed by W. Doug Wylie FCPA, FCMA, ICD.D]
Auditor General

May 19, 2022
Edmonton, Alberta

Consolidated Statement of Operations

Alberta Energy Regulator
Year Ended March 31, 2022

	2022		2021
	Budget (Note 4, Schedule 3)	Actual	Actual
		(in thousands)	
Revenues			
Administration fees	$ 208,023	$ 207,921	$ 114,240
Orphan fund levies and transfers (Note 5)	74,000	77,824	66,952
Government of Alberta grants	28,065	16,988	113,000
Information, services and fees	1,642	2,247	2,731
Investment income	567	573	359
	312,297	305,553	297,282
Expenses			
Energy regulation (Schedule 1)	241,286	221,629	203,753
Orphan well abandonment (Note 5)	74,000	77,824	66,952
	315,286	299,453	270,705
Annual operating surplus (deficit)	(2,989)	6,100	26,577
Accumulated surplus at beginning of year	67,487	67,487	40,910
Accumulated surplus at end of year	$ 64,498	$ 73,587	$ 67,487

The accompanying notes and schedules are part of these consolidated financial statements.

Consolidated Statement of Financial Position

Alberta Energy Regulator
As At March 31, 2022

	2022	2021
	(in thousands)	
Financial assets		
Cash and cash equivalents (Note 6)	$ 52,566	$ 26,226
Accounts receivable (Note 7)	1,684	1,456
Pension assets (Note 14)	3,958	4,923
	58,208	32,605
Liabilities		
Accounts payable and other accrued liabilities (Note 8)	26,725	18,037
Payable to Orphan Well Association	1,064	1,942
Deferred revenue (Note 9)	11,362	325
Deferred lease incentives (Note 12)	11,315	14,332
	50,466	34,636
Net financial assets (net debt)	7,742	(2,031)
Non-financial assets		
Tangible capital assets (Note 15)	57,443	60,133
Prepaid expenses and other assets	8,642	9,385
	66,085	69,518
Net assets before spent deferred capital contributions	73,827	67,487
Spent deferred capital contributions (Note 9)	240	-
Net assets		
Accumulated surplus (Note 16)	$ 73,587	$ 67,487

Contractual rights (Note 17)
Contingent liabilities (Note 18)
Contractual obligations (Note 19)

The accompanying notes and schedules are part of these consolidated financial statements.

Consolidated Statement of Change in Net Financial Assets (Net Debt)

Alberta Energy Regulator
Year Ended March 31, 2022

	2022		2021
	Budget (Note 4, Schedule 3)	Actual	Actual
		(in thousands)	
Annual operating surplus (deficit)	$ (2,989)	$ 6,100	$ 26,577
Acquisition of tangible capital assets (Note 15)	(14,011)	(12,950)	(13,697)
Amortization of tangible capital assets (Note 15)	17,000	13,921	15,686
Write-off of leasehold improvements (Note 12)		1,056	-
Decrease in prepaid expenses and other assets		743	320
Net loss on disposal and write-down of tangible capital assets		663	983
Net increase in spent deferred capital contributions (Note 9)		240	-
Decrease in net debt	-	9,773	29,869
Net debt at beginning of year	(2,031)	(2,031)	(31,900)
Net financial assets (net debt) at end of year	$ (2,031)	$ 7,742	$ (2,031)

The accompanying notes and schedules are part of these consolidated financial statements.

Consolidated Statement of Cash Flows

Alberta Energy Regulator
Year Ended March 31, 2022

	2022	2021
	(in thousands)	
Operating transactions		
Annual operating surplus	$ 6,100	$ 26,577
Non-cash items included in annual operating surplus:		
Amortization of tangible capital assets (Note 15)	13,921	15,686
Write-off of leasehold improvements (Note 12)	1,056	-
Change in pension assets	965	(3,418)
Net loss on disposal and write-down of tangible capital assets	663	983
Bad debt expense (recovery)	(16)	(518)
Write-off of deferred lease incentives (Note 12)	(1,450)	-
Amortization of deferred lease incentives (Note 12)	(1,567)	(1,617)
	19,672	37,693
(Increase)/decrease in accounts receivable	(212)	982
Decrease in prepaid expenses and other assets	743	320
Increase in accounts payable and other accrued liabilities	8,688	808
(Decrease)/increase in payable to Orphan Well Association	(878)	1,333
Increase/(decrease) in deferred revenue	11,037	(401)
Cash provided by operating transactions	39,050	40,735
Capital transactions		
Acquisition of tangible capital assets (Note 15)	(12,950)	(13,697)
Cash applied to capital transactions	(12,950)	(13,697)
Financing transactions		
Increase in spent deferred capital contributions (Note 9)	240	-
Proceeds from line of credit	-	9,855
Debt repayment	-	(10,667)
Cash provided by (applied to) financing transactions	240	(812)
Increase in cash and cash equivalents	26,340	26,226
Cash and cash equivalents at beginning of year	26,226	-
Cash and cash equivalents at end of year	$ 52,566	$ 26,226

The accompanying notes and schedules are part of these consolidated financial statements.

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2022

Note 1 AUTHORITY

The Alberta Energy Regulator (AER) is an independent and quasi-judicial organization of the Government of Alberta. The AER operates under the *Responsible Energy Development Act.* The AER's mandate provides for the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources over their entire life cycle. This includes allocating and conserving water resources, managing public lands, and protecting the environment while providing economic benefits for all Albertans. The AER is exempt from income taxes under the *Income Tax Act.*

Note 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES

These consolidated financial statements are prepared in accordance with Canadian Public Sector Accounting Standards (PSAS).

Reporting Entity and Method of Consolidation

The consolidated financial statements reflect the assets, liabilities, revenues and expenses of the AER, which is composed of all components controlled by the AER. The Orphan Fund is a fund retained and administered by the AER. The AER collects an Orphan Fund Levy and a Large Facility Program Orphan Levy, and transfers the funds to the Orphan Well Association through the Orphan Fund. The AER also transfers funds for first time licensee application fees, including regulator directed transfer fees, and forfeited security deposits through the Orphan Fund. The AER and the Orphan Fund are consolidated using the line-by-line method.

Basis of Financial Reporting

Revenues

All revenues are reported on the accrual basis of accounting. The AER recognizes revenue from administration fees at their realizable value. Cash received for which services have not been provided by year end is recognized as deferred revenue.

Government of Alberta Grants

Transfers from the Government of Alberta are referred to as provincial grants.

Provincial grants without stipulations for the use of the transfer are recognized as revenue when the transfer is authorized and the AER meets the eligibility criteria (if any). Provincial grants with stipulations for the use of the transfer are recognized as deferred revenue and subsequently recognized when the AER meets the stipulations.

Investment Income

Investment income includes interest income.

Expenses

Expenses are reported on an accrual basis. The cost of all goods consumed and services received during the year are expensed.

Employee future benefits

The AER maintains its own defined benefit Senior Employees Pension Plan (SEPP) and two supplementary pension plans to compensate senior staff who do not participate in the government management pension plans. Retirement benefits are based on each employee's years of service and remuneration.

Pension assets represent the sum of the accumulated cash contributions less the sum of the current and prior years' pension expense.

Accrued benefit obligations are actuarially determined using the projected benefit method prorated on length of service and management's best estimate of expected plan investment performance, projected employees' compensation levels and retirement age of employees.

Accrued benefit obligations and pension benefit costs for the year are calculated using the expected rate of return on plan assets as the discount rate, which is determined using market values of plan assets.

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2022

Note 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (continued)

Basis of Financial Reporting (continued)

Employee future benefits (continued)

Actuarial gains and losses are amortized over the average remaining service period of the active employees, which is 11.2 years (2021 - 11.2 years).

Past service cost arising from plan amendments is accounted for in the period of the plan amendments.

Gains and losses determined upon a plan curtailment are accounted for in the period of curtailment.

The AER participates in the Government of Alberta's multi-employer pension plans: Management Employees Pension Plan, Public Service Pension Plan and Supplementary Retirement Plan for Public Service Managers. Defined contribution plan accounting is applied to these plans as the AER has insufficient information to apply defined benefit plan accounting. Accordingly, pension expense comprises employer contributions to the plans that are required for its employees during the year, which are calculated based on actuarially pre-determined amounts that are expected to provide the plans' future benefits.

Valuation of financial assets and liabilities

The AER's financial assets and liabilities are generally measured as follows:

Financial Statement Component	Measurement
Cash and cash equivalents	Cost
Accounts receivable	Lower of cost or net recoverable value
Pension assets	Lower of cost or net recoverable value
Bank indebtedness	Cost
Accounts payable and other accrued liabilities	Cost
Payable to the Orphan Well Association	Cost
Deferred lease incentives	Amortized cost

The AER has not designated any financial assets or liabilities in the fair value category, does not have any significant foreign currency transactions and does not hold any derivative contracts. The AER has no significant remeasurement gains or losses and consequently has not presented a consolidated statement of remeasurement gains and losses.

Financial assets

Financial assets are assets that could be used to discharge existing liabilities or finance future operations and are not for consumption in the normal course of operations.

Financial assets include cash and the AER's financial claims on external organizations and individuals at year end.

Cash and cash equivalents

Cash comprises cash on hand, externally restricted cash and demand deposits.

Accounts receivable

Accounts receivable are recognized at the lower of cost or net recoverable value. A valuation allowance is recognized when recovery is uncertain.

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2022

Note 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (continued)

Basis of Financial Reporting (continued)

Liabilities

Liabilities are present obligations of the AER to external organizations and individuals arising from past transactions or events occurring before the year end, the settlement of which is expected to result in the future sacrifice of economic benefits. They are recognized when there is an appropriate basis of measurement and management can reasonably estimate the amounts. Liabilities include all financial claims payable by the AER at fiscal year end.

Bank indebtedness

Bank indebtedness comprises the amount outstanding (if any) for a revolving line of credit.

Deferred lease incentives

Deferred lease incentives, consisting of leasehold improvement costs, reduced rent benefits and rent-free periods, are amortized on a straight-line basis over the term of the leases.

Environmental Liabilities

Liability for Contaminated Sites:

Contaminated sites are a result of contamination of a chemical, organic or radioactive material or live organism that exceeds an environmental standard, being introduced into soil, water or sediment.

A liability for remediation of a contaminated site may arise from an operation that is either in productive use or no longer in productive use and may also arise from an unexpected event resulting in contamination. The resulting liability is recognized when all of the following criteria are met:

i. an environmental standard exists;
ii. contamination exceeds the environmental standard;
iii. the AER is directly responsible or accepts responsibility;
iv. it is expected that future economic benefits will be given up; and
v. a reasonable estimate of the amount can be made.

Contingent Liabilities

A contingent liability is recognized when:

i. there is an existing condition or situation;
ii. there is an expected future event that will resolve the uncertainty as to whether a present obligation to sacrifice economic benefits exists;
iii. it is likely that a future event will confirm that a liability has been incurred at the date of the financial statements; and
iv. a reasonable estimate of the amount can be made.

Non-financial assets

Non-financial assets are acquired, constructed or developed assets that do not normally provide resources to discharge existing liabilities, but instead:

(a) are normally employed to deliver AER services;
(b) may be consumed in the normal course of operations; and
(c) are not for sale in the normal course of operations.

Non-financial assets of the AER include tangible capital assets, prepaid expenses and other assets.

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2022

Note 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (continued)

Basis of Financial Reporting (continued)

Tangible capital assets

Tangible capital assets are recognized at cost less accumulated amortization, which includes amounts that are directly related to the acquisition, design, construction, development, improvement or betterment of the assets. Cost includes overhead directly attributable to construction and development of the asset.

The cost, less residual value, of the tangible capital assets, excluding land, is amortized over their estimated useful lives as follows:

Leasehold improvements	Straight line	Term of the lease
Furniture and equipment	Straight line	5 - 12 years
Computer hardware	Straight line	4 years
Computer software - purchased	Straight line	4 years
Computer software - developed	Declining balance	5 years

Amortization is only expensed when the tangible capital asset is put into service.

Work-in-progress, which may include developed computer software and leasehold improvements, is not amortized until a project is complete and the asset is put into service.

Tangible capital assets are written down when conditions indicate that they no longer contribute to the AER's ability to provide goods and services, or when the value of future economic benefits associated with the tangible capital assets is less than their net book value. The net write-downs are accounted for as an expense in the Consolidated Statement of Operations.

Prepaid expenses

Prepaid expenses are recognized at cost and amortized based on the terms of the agreements.

Measurement uncertainty

Measurement uncertainty exists when there is a variance between the recognized or disclosed amount and another reasonably possible amount, whenever estimates are used. The amounts recognized for amortization of tangible capital assets are based on estimates of the useful life of the related assets. Accrued defined benefit obligations are subject to measurement uncertainty due to the use of actuarial assumptions. The resulting estimates are within reasonable limits of materiality and are in accordance with the AER's significant accounting policies.

Estimates of contingent liabilities for contaminated sites are subject to measurement uncertainty because the existence and extent of contamination, the responsibility for clean-up, and the timing and costs of remediation cannot be reasonably estimated in all circumstances. The degree of measurement uncertainty cannot be reasonably determined.

Note 3 FUTURE CHANGES IN ACCOUNTING STANDARDS

During the fiscal year 2022-23, the AER will adopt the following new accounting standard of the Public Sector Accounting Board:

PS 3280 Asset Retirement Obligations (effective April 1, 2022)

This standard provides guidance on how to account for and report liabilities for retirement of tangible capital assets. The AER plans to adopt this accounting standard on a modified retroactive basis, consistent with the transitional provisions in PS 3280, and information presented for comparative purposes will be restated. The impact of the adoption of this accounting standard on the consolidated financial statements is currently being analyzed.

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2022

Note 3 FUTURE CHANGES IN ACCOUNTING STANDARDS (continued)

In addition to the above, the Public Sector Accounting Board has approved the following accounting standards, which are effective for fiscal years starting on or after April 1, 2023:

PS 3400 Revenue (effective April 1, 2023)
This standard provides guidance on how to account for and report on revenue, and specifically, it differentiates between revenue arising from exchange and non-exchange transactions.

PS 3160 Public Private Partnerships (effective April 1, 2023)
This standard provides guidance on how to account for public private partnerships between public and private sector entities, where the public sector entity procures infrastructure using a private sector partner.

The AER has not yet adopted these two standards. Management is currently assessing the impact of these standards on the consolidated financial statements.

Note 4 BUDGET

The budget and budget adjustments reflected on Schedule 3 have been approved by the Government of Alberta.

Note 5 ORPHAN WELL ABANDONMENT
(in thousands)

The Government of Alberta has delegated the authority to manage the abandonment and reclamation of wells, facilities, and pipelines that are licensed to defunct licensees to the Orphan Well Association. The AER collects an Orphan Fund Levy and a Large Facility Program Orphan Levy, and transfers the funds to the Orphan Well Association through the Orphan Fund. The AER also transfers funds for first time licensee application fees, including regulator directed transfer fees, and forfeited security deposits through the Orphan Fund. During the year ended March 31, 2022, the AER collected and transferred $73,788 (2021 - $65,225) in levies, $436 (2021 - $473) in application fees and $3,600 (2021 - $1,254) in forfeited security deposits.

Note 6 CASH AND CASH EQUIVALENTS
(in thousands, unless otherwise noted)

Cash and cash equivalents are held in an account with a Canadian chartered bank and earn interest calculated based on the average monthly cash balance. The funds are available to be withdrawn upon request. During the year ended March 31, 2022, the AER earned interest at an annual average rate of 0.8% (2021 - 0.7%).

Cash and cash equivalents includes restricted funds of $10,837 (2021 - $nil), as reflected in deferred revenue (discussed in Note 9), which is to be used primarily for future expenditures related to the Government of Alberta's Minerals Strategy - Public Geoscience program.

Note 7 ACCOUNTS RECEIVABLE
(in thousands)

Accounts receivable are unsecured and non-interest bearing.

	2022			2021
	Gross amount	Allowance for doubtful accounts	Net recoverable value	Net recoverable value
Accounts receivable	$ 2,416	$ (732)	$ 1,684	$ 1,456

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2022

Note 8 ACCOUNTS PAYABLE AND OTHER ACCRUED LIABILITIES

(in thousands)

	2022	2021
Trade and other accrued liabilities	$ 9,991	$ 8,518
Lease termination payable	7,376	-
Accrued salaries and benefits	6,868	7,204
Trade accounts payable	2,490	2,315
	$ 26,725	$ 18,037

Note 9 DEFERRED REVENUE

(in thousands)

Deferred revenue consists of the following:

	Year ended March 31, 2022		As at March 31, 2022	As at March 31, 2021
	Total Revenue Received	Actual Revenue Recognized	Deferred Revenue	
Program				
Public Geoscience(1)	$ 24,760	$ 14,013	$ 10,747	$ -
Mineral Regulatory Framework	2,000	1,910	90	-
Geothermal Regulatory Framework	1,065	1,065	-	-
Total Grant Revenue	27,825	16,988	10,837	-
Other	538	338	525	325
	$ 28,363	$ 17,326	$ 11,362	$ 325
Spent deferred capital contributions(1)	$ 240	$ -	$ 240	$ -

(1) During 2022, the AER purchased capital assets of $240 with funds from the Public Geoscience grant. Revenue has not been recognized for these funds as amortization has not been recorded for these capital assets at March 31, 2022.

Note 10 FINANCIAL INSTRUMENTS

The AER has the following financial instruments: cash and cash equivalents, accounts receivable, accounts payable and other accrued liabilities, and payable to the Orphan Well Association.

Financial Risk Management

The AER has exposure to the following risks from its use of financial instruments:

(a) Liquidity risk

Liquidity risk is the risk that the AER will encounter difficulty in meeting obligations associated with its financial liabilities. Liquidity requirements of the AER are met primarily through the collection of funding at the beginning of the year to fund operating expenses and capital expenditures throughout the year. The AER manages liquidity risk by having established budget processes and regularly monitoring cash flows to ensure the necessary funds are on hand to fulfill upcoming obligations. In addition, the AER maintains a revolving line of credit which provides financial flexibility to allow the AER to meet its obligations if funding cannot be collected on a timely basis.

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2022

Note 10 FINANCIAL INSTRUMENTS (continued)

(b) Credit risk

The AER is exposed to credit risk from potential non-payment of accounts receivable. A substantial portion of the AER's accounts receivable include balances due from operators in the oil and gas industry, and are subject to normal industry credit risk. The AER regularly monitors the financial status of operators and assesses the collectability of accounts receivable. The AER's maximum exposure to credit risk is limited to the carrying amount of accounts receivable presented in the Consolidated Statement of Financial Position at the reporting date. The AER established a valuation allowance that corresponds to the specific credit risk of operators, historical trends and economic circumstances.

Note 11 REVOLVING LINE OF CREDIT

(in thousands, unless otherwise noted)

The AER has an unsecured $50 million (2021 - $75 million) revolving line of credit. Amounts borrowed can only be applied to general corporate purposes and exclude the funding of capital expenditures.

Bank advances on the line of credit are payable on demand and bear interest at a rate of prime less 0.75%. For the year ended March 31, 2022, interest expense on the revolving line of credit was $nil (2021 - $4).

Note 12 DEFERRED LEASE INCENTIVES

(in thousands)

The AER has entered into various lease agreements which provide for lease incentives comprising reduced rent benefits, rent-free periods and leasehold improvement costs. These amounts are amortized on a straight-line basis over the term of the lease.

	2022			2021
	Leasehold improvement costs	Reduced rent benefits and rent-free periods	Total	Total
Balance at beginning of year	$ 11,639	$ 2,693	$ 14,332	$ 15,949
Write-off of lease incentives[1]	(1,056)	(394)	(1,450)	-
Amortization	(1,213)	(354)	(1,567)	(1,617)
Balance at end of year	$ 9,370	$ 1,945	$ 11,315	$ 14,332

(1) In 2022, the AER exited a portion of the lease for its Calgary Head Office. As a result, the AER wrote off the related leasehold improvements and lease incentives pertaining to this office space.

Note 13 ENVIRONMENTAL LIABILITIES

(in thousands, unless otherwise noted)

The AER has a mandate to protect public safety and the environment. As at March 31, 2022, the AER is not responsible, nor has it accepted responsibility, for performing remediation and reclamation work at contaminated sites. The AER has $nil (2021 - $nil) environmental liabilities recorded.

As at March 31, 2022, the AER is administering 29 (2021 – 28) legacy sites. Of these sites, during the year ended March 31, 2022, the AER identified two (2021 – five) sites as having immediate public safety and environmental risk, and the AER needed to take appropriate action to mitigate these risks. During the year ended March 31, 2022, the AER incurred $9 (2021 - $906) in costs to mitigate immediate public safety and environmental risks. Costs to mitigate immediate public safety or environmental risks are costs where the AER has completed protective or remediation work at legacy sites. Costs for ongoing assessment and monitoring are included.

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2022

Note 14 EMPLOYEE FUTURE BENEFITS

(in thousands, unless otherwise noted)

The AER participates in the Government of Alberta's multi-employer pension plans: Management Employees Pension Plan, Public Service Pension Plan and Supplementary Retirement Plan for Public Service Managers. For the year ended March 31, 2022, the expense for these pension plans is equal to the contributions of $12,253 (2021 - $12,539) and is included in salaries, wages and employee benefits on Schedule 1. The AER is not responsible for future funding of the plan deficit other than through contribution increases.

In addition, the AER maintains its own defined benefit Senior Employees Pension Plan (SEPP) and two supplementary pension plans to compensate senior staff who do not participate in the government management pension plans. Retirement benefits are based on each employee's years of service and remuneration.

All the information presented in the note below is related to the AER's defined benefit pension plans.

The effective date of the most recent actuarial funding valuation for SEPP was December 31, 2018. The accrued benefit obligation as at March 31, 2022 is based on the extrapolation of the results of this valuation. The effective date of the next required funding valuation for SEPP is December 31, 2021. The actuarial funding valuation for December 31, 2021 is expected to be completed in the first half of 2022.

Pension plan assets are valued at market values. During the year ended March 31, 2022, the weighted average actual return on plan assets was 5.2% (2021 - 14.7%).

Significant weighted average actuarial and economic assumptions used to value accrued benefit obligations and pension benefit costs were as follows:

Accrued benefit obligations	2022	2021
Discount rate	4.5%	4.4%
Rate of compensation increase	4.0% until March 31, 2023, 3.0% thereafter	0% until March 31, 2022, 3.0% thereafter
Long-term inflation rate	2.0%	2.0%

Pension benefit costs for the year	2022	2021
Discount rate	4.4%	4.8%
Expected rate of return on plan assets	4.4%	4.8%
Rate of compensation increase	0% until March 31, 2022, 3.0% thereafter	0% until March 31, 2021, 3.5% thereafter

The funded status and amounts recognized in the Consolidated Statement of Financial Position were as follows:

	2022	2021
Market value of plan assets	$ 76,893	$ 74,119
Accrued benefit obligations	(70,739)	(70,954)
Plan surplus	6,154	3,165
Unamortized actuarial (gains)/losses	(2,196)	1,758
Pension assets	$ 3,958	$ 4,923

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2022

Note 14 EMPLOYEE FUTURE BENEFITS (continued)

(in thousands, unless otherwise noted)

The pension benefit costs for the year included the following components:

	2022	2021
Current period benefit cost	$ 4,045	$ 3,976
Interest cost	3,197	3,442
Expected return on plan assets	(3,227)	(3,039)
Amortization of actuarial losses	251	804
	$ 4,266	$ 5,183

Additional information about the defined benefit pension plans is as follows:

	2022	2021
Benefits paid	$ 4,636	$ 10,171
AER contributions	3,163	8,600
Employees' contributions	663	683

The asset allocation of the defined benefit pension plans' investments was as follows:

	2022	2021
Equity securities	44.1%	48.2%
Debt securities	23.4%	22.2%
Alternatives	20.0%	17.3%
Other	12.5%	12.3%
	100.0%	100.0%

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2022

Note 15 TANGIBLE CAPITAL ASSETS

(in thousands)

	2022					2021
	Land	Leasehold improvements	Furniture and equipment [1]	Computer hardware and software	Total	Total
Estimated useful life	Indefinite	Term of the lease	5-12 years	4-5 years		
Historical cost [2]						
Beginning of year	$ 282	$ 46,500	$ 13,060	$ 148,562	$ 208,404	$ 202,549
Additions	-	2,168	580	10,202	12,950	13,697
Disposals, including write-downs[3]	-	(2,302)	(1,240)	(20,426)	(23,968)	(7,842)
	282	46,366	12,400	138,338	197,386	208,404
Accumulated amortization						
Beginning of year	$ -	$ 22,913	$ 9,906	$ 115,452	$ 148,271	$ 139,444
Amortization expense	-	2,717	823	10,381	13,921	15,686
Effect of disposals, including write-downs[3]	-	(1,246)	(1,200)	(19,803)	(22,249)	(6,859)
	-	24,384	9,529	106,030	139,943	148,271
Net book value at March 31, 2022	$ 282	$ 21,982	$ 2,871	$ 32,308	$ 57,443	
Net book value at March 31, 2021	$ 282	$ 23,587	$ 3,154	$ 33,110		$ 60,133

(1) Furniture and equipment includes organization-onwed vehicles, office equipment, furniture and other equipment.

(2) As at March 31, 2022, historical cost of computer hardware and software includes work-in-progress totalling $2,297 (2021 - $6,630).

(3) In October 2021, the AER exited a portion of the lease for its Calgary Head Office, resulting in a reduction of $2,302 in leasehold improvements and $1,246 in accumulated amortization. No loss was recognized as the write-off of the leasehold improvements was offset by the write-off of the related lease incentive.

Note 16 ACCUMULATED SURPLUS

(in thousands)

The accumulated surplus of the AER is calculated as the sum of the AER's net debt and its non-financial assets. The accumulated surplus represents the net assets of the AER and comprises the following:

	2022			2021
	Investments in tangible capital assets [a]	Unrestricted net assets	Total	Total
Balance at beginning of year	$ 48,494	$ 18,993	$ 67,487	$ 40,910
Annual operating surplus	-	6,100	6,100	26,577
Net investment in tangible capital assets [a]	(421)	421	-	-
Balance at end of year	$ 48,073	$ 25,514	$ 73,587	$ 67,487

(a) Excludes leasehold improvement costs received by the AER as a lease incentive and related amortization.

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2022

Note 17 CONTRACTUAL RIGHTS

(in thousands)

Contractual rights are rights of the AER to economic resources arising from contracts or agreements that will result in both assets and revenues in the future when the terms of those contracts or agreements are met.

During the year ended March 31, the AER collected the following amounts for its contractual rights under operating subleases:

	2022	2021
Contractual rights from operating subleases	$ 316	$ 110

As at March 31, 2022, estimated amounts that will be received or receivable for each of the next five years are as follows:

2022-23	$ 555
2023-24	565
2024-25	433
2025-26	440
2026-27	182
	$ 2,175

Note 18 CONTINGENT LIABILITIES

(in thousands)

The AER is involved in legal matters where damages are being sought. These matters may give rise to contingent liabilities.

Accruals have been made in specific instances where it is likely that losses will be incurred based on a reasonable estimate. As at March 31, 2022, accruals totalling $1,359 (2021 - $125) have been recognized as a liability.

The AER has identified various sites where contamination may exist and the level of contamination is unknown at this time. As at March 31, 2022, no liability has been recognized for these sites as further testing and evaluation is required to determine the extent of immediate actions necessary. No liability for remediation on other sites has been recognized as the AER becoming responsible for these sites is not determinable; the AER does not expect to give up any future economic benefits; no reasonable estimate of the amount can be made; or a combination of these factors. The AER's ongoing efforts to assess contaminated sites may result in environmental remediation liabilities related to newly identified sites, or change in the assessment or intended use of existing sites. Any change to the environmental liabilities will be accrued in the year in which they are assessed as likely and measurable.

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2022

Note 19 CONTRACTUAL OBLIGATIONS

(in thousands)

As at March 31, 2022, the AER had contractual obligations totalling $146,445 (2021 - $162,248).

Contractual obligations are obligations of the AER to others that will become liabilities in the future when the terms of those contracts or agreements are met.

As at March 31, 2022, estimated payment requirements for obligations under operating leases and contracts for each of the next five years and thereafter are as follows:

2022-23	$ 48,943
2023-24	30,071
2024-25	11,577
2025-26	10,059
2026-27	9,443
Thereafter	36,352
	$ 146,445

Note 20 ASSETS UNDER ADMINISTRATION

(in thousands)

The AER administers security deposits in accordance with specified acts and regulations. Security deposits are held on behalf of depositors with no power of appropriation and therefore are not reported in these consolidated financial statements. The AER does not have any financial risk associated with security collected. Security, along with any interest earned, will be returned to the depositors upon meeting specified refund criteria. Security may be forfeited and transferred to the Orphan Well Association for the cost of suspension, abandonment, site decontamination and surface land reclamation.

As at March 31, 2022, assets under administration included the following types of security deposits:

	2022	2021	2022	2021
	Cash	Cash	Letters of credit	Letters of credit
Liability Management Rating programs and landfills	$ 89,277	$ 90,431	$ 278,826	$ 225,418
Mine Financial Security program	41,064	39,342	1,479,452	1,447,447
Other programs	10,629	10,446	10,505	7,714
	$ 140,970	$ 140,219	$ 1,768,783	$ 1,680,579

Note 21 COMPARATIVE FIGURES

Certain 2021 figures have been reclassified, where necessary, to conform to the 2022 presentation.

Note 22 APPROVAL OF CONSOLIDATED FINANCIAL STATEMENTS

These consolidated financial statements were approved by the AER Board of Directors on May 19, 2022.

Energy Regulation Expenses – Detailed by Object

Alberta Energy Regulator
Year Ended March 31, 2022
Schedule 1

	2022	2021
	(in thousands)	
Salaries, wages and employee benefits	$ 132,712	$ 131,598
Buildings	27,305	20,354
Consulting services	26,539	14,634
Computer services	17,710	17,112
Amortization of tangible capital assets	13,921	15,686
Travel and transportation	1,292	1,382
Administrative	1,274	915
Loss on disposal and write-down of tangible capital assets	663	983
Equipment rent and maintenance	205	323
Abandonment and enforcement	8	766
	$ 221,629	$ 203,753

Salary and Benefits Disclosure

Alberta Energy Regulator
Year Ended March 31, 2022
Schedule 2

	2022				2021
	Base salary [(a)]	Other cash benefits [(b)]	Other non-cash benefits [(c)]	Total	Total
			(in thousands)		
Position					
Board of Directors					
Chair [(d)]	$ 130	$ -	$ 15	$ 145	$ 138
Members [(e)]	306	-	17	323	354
Executives					
President and Chief Executive Officer [(f)]	334	39	91	464	422
Chief Hearing Commissioner	218	30	48	296	289
Chief Operations Officer [(g)]	264	21	62	347	340
Executive Vice-President, Law and General Counsel	276	8	62	346	343
Vice-President of Finance and Chief Financial Officer [(h,k)]	233	9	85	327	191
Former President and Chief Executive Officer [(i)]	-	-	-	-	23
Former Executive Vice-President, Corporate Services [(j,k)]	-	-	-	-	504

(a) Base salary includes retainers and per diems for Board Directors and regular base salary for Executives.

(b) Other cash benefits includes payments in lieu of vacation, pension and health benefits, as well as vehicle allowances and other cash reimbursements.

(c) Other non-cash benefits includes contributions to all benefits as applicable, including employer's share of all employee benefits and contributions or payments made on behalf of employees, including pension, supplementary retirement plans, health care and payments made for professional memberships, tuition fees, parking and other taxable benefits.

(d) The current Chair was appointed on April 15, 2020, and is remunerated with a monthly honorarium as per rates prescribed in the Orders in Council. Prior to the current Chair's appointment, the previous Chair's remuneration was set at $nil while this individual occupied the position from September 6, 2019 until April 15, 2020.

(e) The incumbent Board of Directors consists of six members. Five Board members are remunerated with monthly honoraria as per rates prescribed in the Orders in Council. Remuneration for one Board member is set at $nil. As at April 1, 2020, the Board of Directors consisted of four members. On April 15, 2020, one member resigned and four new members were appointed. On June 5, 2020, one member was rescinded.

(f) The incumbent held the position effective April 15, 2020.

(g) The incumbent held the position of Executive Vice- President, Operations until February 24, 2021, at which time the incumbent was appointed to the position of Chief Operations Officer.

(h) The incumbent held the position effective September 8, 2020, at this time the position became a voting member of the Executive Leadership Team. Prior to this appointment, the position was a non-voting member of the Executive Leadership Team.

(i) The incumbent held the position until April 15, 2020, at which time the incumbent's contract ended.

(j) The incumbent held the position until February 24, 2021, at which time the position was eliminated and the incumbent was terminated. Other cash benefits include $170 of severance pay.

(k) Under the terms of the AER's defined benefit SEPP and two supplementary retirement plans (SRP), employees may receive supplemental retirement payments. Retirement arrangement costs as detailed below are not cash payments in the period but are the period expense for rights to future compensation. Costs shown reflect the total estimated cost to provide annual pension income over an actuarially determined post-employment period. The SEPP and SRP provide future pension benefits to participants based on years of service and remuneration. The cost of these benefits is actuarially determined using the projected benefit method pro-rated on service, a market interest rate and management's best estimate of expected costs and period of benefit coverage. Net actuarial gains and losses of the benefit obligations are amortized over the average remaining service life of the employee group. Current service cost is the actuarial present value of the benefits earned in the fiscal year. Prior service and other costs include amortization of past service costs, amortization of actuarial gains and losses, and interest accruing on the actuarial liability.

Salary and Benefits Disclosure

Alberta Energy Regulator
Year Ended March 31, 2022
Schedule 2 (continued)

SEPP AND SRP RETIREMENT BENEFITS
(in thousands)

The costs detailed below are only for those employees, included in Schedule 2, who were employed during the years ended March 31, 2021 and 2022, and participated in the SEPP and SRP maintained by the AER. The SEPP and SRP provide retirement benefits to compensate senior staff who do not participate in the Government of Alberta's management pension plans.

	2022			2021
Position	**Current service cost**	**Prior service and other costs**	**Total**	**Total**
Vice-President of Finance and Chief Financial Officer	$ 39	$ -	$ 39	$ 23
Former Executive Vice-President, Corporate Services	-	-	-	34

The SEPP and SRP accrued obligation for each executive employed by the AER during the years ended March 31, 2021 and 2022 is outlined in the following table:

Position	Accrued obligation April 1, 2021	Changes in accrued obligation	Accrued obligation March 31, 2022	Accrued obligation March 31, 2021
Vice-President of Finance and Chief Financial Officer	$ 25	$ 32	$ 57	$ 25
Former Executive Vice-President, Corporate Services	187	(187)	-	187

Consolidated Actual Results Compared with Budget

Alberta Energy Regulator
Year Ended March 31, 2022
Schedule 3

	Budget (Note 4)	Adjustments [a]	Adjusted budget	Actual
		(in thousands)		
Revenues				
Administration fees	$ 206,592	$ 1,431	$ 208,023	$ 207,921
Orphan fund levies and transfers	74,000	-	74,000	77,824
Government of Alberta grants	3,065	25,000	28,065	16,988
Information, services and fees	1,745	(103)	1,642	2,247
Investment income	867	(300)	567	573
	286,269	26,028	312,297	305,553
Expenses				
Energy regulation	208,269	33,017	241,286	221,629
Orphan well abandonment	74,000	-	74,000	77,824
	282,269	33,017	315,286	299,453
	4,000	(6,989)	(2,989)	6,100
Capital				
Capital investment	14,500	(489)	14,011	12,950
Less: Amortization of tangible capital assets	(17,000)	-	(17,000)	(13,921)
Loss on disposal and write-down of tangible capital assets				(663)
Net capital investment	(2,500)	(489)	(2,989)	(1,634)
Surplus (deficit)	$ 6,500	$ (6,500)	$ -	$ 7,734

(a) Adjustments reflect changes to the original budget submitted by the AER during the fiscal year. Budget and adjustments were approved by the Treasury Board of the Government of Alberta, and were mainly due to provincial grants announced for its Minerals Strategy, and related expenditures, as well as expenses recognized by the AER as a result of exiting a portion of its Calgary Head Office lease.

Related Party Transactions

Alberta Energy Regulator
Year Ended March 31, 2022
Schedule 4

The AER, in the normal course of business, entered into various transactions with entities consolidated or accounted for on the modified equity basis in the Government of Alberta's Consolidated Financial Statements. These entities are considered to be related parties of the AER. Related parties also include key management personnel and close family members of those individuals in the AER. In 2022, there were no amounts or transactions, other than compensation, between the AER and its key management personnel. Key management personnel compensation is disclosed in Schedule 2.

Related Party Transactions with Government of Alberta Entities

The AER recognized the following transactions with Government of Alberta entities in the Consolidated Statement of Operations and the Consolidated Statement of Financial Position at the amount of consideration agreed upon between the related parties:

	Entities in the Ministry of Energy		Other entities	
	2022	2021	2022	2021
	(in thousands)		(in thousands)	
Revenues				
Government of Alberta grants	$ 16,988	$ 113,000	$ -	$ -
Information, services and fees	334	366	485	361
	$ 17,322	$ 113,366	$ 485	$ 361

	Entities in the Ministry of Energy		Other entities	
	2022	2021	2022	2021
	(in thousands)		(in thousands)	
Expenses				
Computer services	$ 386	$ 418	$ 3,573	$ 2,975
Buildings	-	-	400	528
Administrative	-	-	370	396
Consulting services	-	-	187	310
	$ 386	$ 418	$ 4,530	$ 4,209
Receivable from	$ 137	$ 108	$ 6	$ 33
Prepaid expenses and other assets	$ -	$ -	$ 36	$ 36
Payable to	$ -	$ 209	$ 1,307	$ 641
Deferred revenue	$ 10,837	$ 1	$ 259	$ -
Contractual obligations [a]	$ -	$ -	$ 4,850	$ 7,069

[a] Contractual obligations are obligations of the AER to related parties that will become liabilities in the future when the terms of those contracts or agreements are met.

Alberta Utilities Commission

Financial Statements

For the Year Ended March 31, 2022

Table of Contents

Auditor General OF ALBERTA

Independent Auditor's Report

To the Members of the Alberta Utilities Commission

Report on the Financial Statements

Opinion

I have audited the financial statements of the Alberta Utilities Commission (the Commission), which comprise the statement of financial position as at March 31, 2022, and the statements of operations, change in net financial assets, and cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In my opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Commission as at March 31, 2022, and the results of its operations, its changes in net financial assets, and its cash flows for the year then ended in accordance with Canadian public sector accounting standards.

Basis for opinion

I conducted my audit in accordance with Canadian generally accepted auditing standards. My responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of my report. I am independent of the Commission in accordance with the ethical requirements that are relevant to my audit of the financial statements in Canada, and I have fulfilled my other ethical responsibilities in accordance with these requirements. I believe that the audit evidence I have obtained is sufficient and appropriate to provide a basis for my opinion.

Other information

Management is responsible for the other information. The other information comprises the information included in the *Annual Report*, but does not include the financial statements and my auditor's report thereon. The *Annual Report* is expected to be made available to me after the date of this auditor's report.

My opinion on the financial statements does not cover the other information and I do not express any form of assurance conclusion thereon.

In connection with my audit of the financial statements, my responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or my knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work I will perform on this other information, I conclude that there is a material misstatement of this other information, I am required to communicate the matter to those charged with governance.

Responsibilities of management and those charged with governance for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with Canadian public sector accounting standards, and for such internal control as management determines is necessary to enable the preparation of the financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Commission’s ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless an intention exists to liquidate or to cease operations, or there is no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Commission’s financial reporting process.

Auditor's responsibilities for the audit of the financial statements

My objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes my opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, I exercise professional judgment and maintain professional skepticism throughout the audit. I also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for my opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Commission's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management’s use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Commission’s ability to continue as a going concern. If I conclude that a material uncertainty exists, I am required to draw attention in my auditor’s report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify my opinion. My conclusions are based on the audit evidence obtained up to the date of my auditor’s report. However, future events or conditions may cause the Commission to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

I communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that I identify during my audit.

[Original signed by W. Doug Wylie FCPA, FCMA, ICD.D]
Auditor General

May 11, 2022
Edmonton, Alberta

Statement of Operations

Alberta Utilities Commission
Year Ended March 31, 2022

	2022		2021
	Budget (Schedule 3)	Actual	Actual
	(in thousands)		
Revenues			
Administration fees	$ 31,377	$ 27,273	$ 29,971
Investment income	150	37	73
Professional services and other revenue	150	244	145
	31,677	27,554	30,189
Expenses			
Utility regulation (Schedule 1)	31,477	28,070	30,558
Annual operating surplus (deficit)	200	(516)	(369)
Accumulated surplus, beginning of year	12,902	12,902	13,271
Accumulated surplus, end of year	**$ 13,102**	**$ 12,386**	**$ 12,902**

The accompanying notes and schedules are part of these financial statements.

Statement of Financial Position

Alberta Utilities Commission
As At March 31, 2022

	2022	2021
	(in thousands)	
Financial Assets		
Cash and cash equivalents (Note 5)	$ 9,899	$ 9,477
Accounts receivable	83	94
Accrued pension asset (Note 6)	769	723
	10,751	10,294
Liabilities		
Accounts payable and other accrued liabilities (Note 7)	2,006	2,181
Deferred lease incentive (Note 8)	4,121	4,798
	6,127	6,979
Net Financial Assets	4,624	3,315
Non-Financial Assets		
Capital assets (Note 9)	7,016	8,576
Prepaid expenses	746	1,011
	7,762	9,587
Net Assets		
Accumulated surplus (Note 10)	$ 12,386	$ 12,902

Contractual obligations (Note 11)

The accompanying notes and schedules are part of these financial statements.

Statement of Change in Net Financial Assets

Alberta Utilities Commission
Year Ended March 31, 2022

	2022		2021
	Budget (Schedule 3)	**Actual**	**Actual**
	(in thousands)		
Annual operating surplus (deficit)	$ 200	$ (516)	$ (369)
Acquisition of capital assets (Note 9)	(2,000)	(389)	(288)
Amortization of capital assets (Note 9)	1,800	1,693	1,858
Net loss on disposal and writedowns of capital assets	-	215	4
Proceeds on disposal of capital assets	-	41	1
Decrease in prepaid expenses	-	265	186
Increase in net financial assets in the year	-	1,309	1,392
Net financial assets, beginning of year	3,315	3,315	1,923
Net financial assets, end of year	**$ 3,315**	**$ 4,624**	**$ 3,315**

The accompanying notes and schedules are part of these financial statements.

Statement of Cash Flows

Alberta Utilities Commission
Year Ended March 31, 2022

	2022	2021
	(in thousands)	
Operating transactions		
Annual operating deficit	$ (516)	$ (369)
Non-cash items included in annual deficit:		
Amortization of capital assets (Note 9)	1,693	1,858
Pension expense	634	935
Net loss on disposal and writedowns of capital assets	215	4
Decrease (increase) in accounts receivable	11	(20)
Decrease in prepaid expenses	265	186
(Decrease) increase in accounts payable and other accrued liabilities	(156)	668
Cash provided by operating transactions	2,146	3,262
Capital transactions		
Acquisition of capital assets (Note 9)	(389)	(288)
Proceeds on disposal of capital assets	41	1
Cash applied to capital transactions	(348)	(287)
Financing transactions		
Pension obligations funded	(680)	(1,073)
Net lease incentives amortized	(677)	(761)
Net lease obligations repaid	(19)	(20)
Cash applied to financing transactions	(1,376)	(1,854)
Increase in cash and cash equivalents	422	1,121
Cash and cash equivalents, beginning of year	9,477	8,356
Cash and cash equivalents, end of year	**$ 9,899**	**$ 9,477**

The accompanying notes and schedules are part of these financial statements.

Notes to the Financial Statements

Alberta Utilities Commission
March 31, 2022
(in thousands of dollars)

Note 1 Authority

The Alberta Utilities Commission (AUC) operates under authority of the *Alberta Utilities Commission Act, Chapter A-37.2* . The AUC also exercises powers and authorities under a number of other statutes. The AUC is an independent, quasi-judicial agency of the government of Alberta that ensures the delivery of Alberta's utility services takes place in a manner that is fair, responsible, and in the public interest. The AUC regulates investor owned electric, natural gas and water utilities, and certain municipally owned electricity utilities to ensure customers receive safe and reliable service at just and reasonable rates. The AUC is responsible for making timely decisions on the need, siting, construction, alteration, operation and decommissioning of natural gas and certain electricity transmission facilities. The AUC also regulates power plants in a similar fashion except the need for new power plants is determined by market forces. The AUC develops and amends rules that support the orderly operation of the retail natural gas and electricity markets, and adjudicates on market and operational rule contraventions that the Market Surveillance Administrator may bring before the AUC. The AUC is exempt from income taxes under the *Income Tax Act* .

Note 2 Summary of significant accounting policies and reporting practices

Basis of financial reporting

These financial statements are prepared in accordance with Canadian Public Sector Accounting Standards (PSAS). Significant accounting policies are as follows:

Revenues
All revenues are reported on the accrual basis of accounting. Cash received for which services have not been provided by year end is recognized as unearned revenue and recorded in accounts payable and other accrued liabilities.

Expenses
All expenses are reported on the accrual basis of accounting. The cost of all goods consumed and services received during the year is expensed. Contributed services are not recognized in the Statement of Operations but are disclosed in Note 12 of the financial statements.

Foreign currency translation
Foreign currency transactions are translated at the exchange rate prevailing at the date of transaction. Monetary liabilities denominated in foreign currencies are translated to Canadian dollars at the exchange rate prevailing at fiscal year-end.

Valuation of financial assets and liabilities
The AUC's financial assets and liabilities are generally measured as follows:

Financial Statement Component	Measurement
Cash and cash equivalents	Cost
Accounts receivable	Lower of cost or net recoverable value
Accrued pension asset	Projected benefit method
Accounts payable and other accrued liabilities	Cost
Deferred lease incentive	Amortized cost
Capital lease obligation	Lower of cost or present value of minimum lease payments

The AUC does not carry any financial assets or liabilities at fair value and has no derivatives or unsettled exchange gains or losses, therefore the statement of remeasurement gains or losses is not included in these financial statements.

Notes to the Financial Statements

Alberta Utilities Commission
March 31, 2022
(in thousands of dollars)

Note 2 Summary of significant accounting policies and reporting practices (continued)

Financial assets
Financial assets are assets that could be used to discharge existing liabilities or finance future operations and are not for consumption in the normal course of operations.

Financial assets are the AUC's financial claims on external organizations and individuals at the year end.

Cash and cash equivalents
Cash comprises cash on hand and demand deposits.

Accounts receivable
Accounts receivable are recognized at the lower of cost or net recoverable value. A valuation allowance is recorded when recovery is uncertain.

Accrued pension asset
Accrued pension asset represents pension plan contributions made in excess of the pension expense which is actuarially determined using the projected benefit method prorated on length of service and management's best estimate of expected plan investment performance, projected employees' compensation levels, and length of service to the time of retirement.

For the purpose of calculating pension expense, the AUC uses the expected future rate of return on plan assets as its discount rate. For the purpose of calculating the expected return, plan assets are valued at market-related values.

Past service costs arising from plan amendments are expensed in the period of the plan amendment. Any actuarial gain or loss is amortized over the average remaining service period of active employees.

Defined contribution plan accounting is applied to the government of Alberta multi-employer defined benefit pension plans as the AUC has insufficient information to apply defined benefit plan accounting.

Liabilities
Liabilities are present obligations of the AUC to external organizations and individuals arising from past transactions or events occurring before the year end, the settlement of which is expected to result in the future sacrifice of economic benefits. They are recognized when there is an appropriate basis of measurement and management can reasonably estimate the amounts. Generally, liabilities include trade payables, accrued liabilities and accrued employee vacation entitlements.

Deferred lease incentive
Lease incentive benefits are amortized on a straight line basis over the term of lease as a reduction to rental expense.

Capital lease obligation
Capital lease obligation and the corresponding leased capital asset is recorded at the lower of the leased property's fair value and the present value of the minimum lease payments.

Non-financial assets
Non-financial assets are acquired, constructed, or developed assets that do not normally provide resources to discharge existing liabilities, but instead:

(a) are normally employed to deliver AUC services;
(b) may be consumed in the normal course of operations; and
(c) are not for sale in the normal course of operations.

Notes to the Financial Statements

Alberta Utilities Commission
March 31, 2022
(in thousands of dollars)

Note 2 Summary of significant accounting policies and reporting practices (continued)

Non-financial assets include capital assets and prepaid expenses.

Capital assets
Capital assets are recognized at cost, which includes amounts that are directly related to the acquisition, design, construction, development, improvement or betterment of the assets.

The cost, less residual value, of capital assets, are amortized on a straight-line basis over its estimated useful life as follows:

Computer hardware and software	Four to seven years
Furniture and equipment	Four to forty years
Leasehold improvements	Lease term

Capital assets are written down when conditions indicate that they no longer contribute to the AUC's ability to provide services, or when the value of future economic benefits associated with the capital assets are less than their net book value. The net write-downs are accounted for as expenses in the Statement of Operations.

The capitalization threshold for all capital assets is $1.5 unless they are included in certain capital asset pools.

Prepaid expenses
Prepaid expenses are recorded at cost and amortized based on the terms of the agreement.

Measurement uncertainty
Measurement uncertainty exists when there is a variance between the recognized or disclosed amount and another reasonably possible amount. The amounts recorded for amortization of capital assets are based on estimates of the useful life of the related assets. Also, the accrued pension asset incorporates multiple assumptions. Actual results for amortization and accrued pension asset may differ from reported values.

Note 3 Future changes in accounting standards

During the fiscal year 2022-2023, the AUC will adopt the following new accounting standard of the Public Sector Accounting Board:

PS 3280 Asset Retirement Obligations (effective April 1, 2022)
This accounting standard provides guidance on how to account for and report liabilities for retirement of tangible capital assets. The AUC plans to adopt this accounting standard on a modified retroactive basis, consistent with the transitional provisions in PS 3280, and information presented for comparative purposes will be restated. The impact of the adoption of this accounting standard on the financial statements is currently being analyzed.

In addition to the above, the Public Sector Accounting Board has approved the following accounting standards, which are effective for fiscal years starting on or after April 1, 2023:

PS 3400 Revenue (effective April 1, 2023)
This accounting standard segregates revenue into exchange and non-exchange transactions. Revenue for exchange transactions is recognized when each performance obligation is satisfied. Non-exchange transactions do not contain performance obligations. Management has performed a review of PS 3400 Revenue and does not anticipate a change from its current revenue recognition policy.

PS 3160 Public Private Partnerships (effective April 1, 2023)
This accounting standard provides guidance on how to account for public private partnerships between public and private sector entities, where the public sector entity procures infrastructure using a private sector partner. Management does not anticipate any impact on the financial statements as the AUC does not procure any infrastructure using a private sector partner.

The AUC has not yet adopted these standards.

Notes to the Financial Statements

Alberta Utilities Commission
March 31, 2022
(in thousands of dollars)

Note 4 Financial instruments

The AUC has the following financial instruments: accounts receivable, accounts payable and other accrued liabilities.

The AUC has exposure to the following risks from its use of financial instruments:

Liquidity risk
Liquidity risk is the risk that the AUC will encounter difficulty in meeting obligations associated with financial liabilities. The AUC does not consider this to be a significant risk as it collects the majority of annual revenues at the beginning of the year and maintains a significant cash reserve to meet all obligations that arise during the year.

Credit risk
The AUC is not exposed to any significant credit risk from potential non-payment of accounts receivable. As at March 31, 2022, the balance of accounts receivables does not contain amounts that were past due or uncollectible.

Note 5 Cash and cash equivalents

Cash and cash equivalents consist of deposits in the Consolidated Cash Investment Trust Fund which is managed by the Province of Alberta to provide interest income at competitive rates while maintaining appropriate security and liquidity of depositors' capital. The Fund is comprised of high quality short-term and mid-term fixed income securities with a maximum term to maturity of three years. As at March 31, 2022, securities held by the Fund have a time-weighted return of 0.2 per cent per annum (2021: 0.4 per cent).

Note 6 Pension

The AUC participates in the Government of Alberta's multi-employer pension plans of Management Employees Pension Plan, Public Service Pension Plan, and Supplementary Retirement Plan for Public Service Managers. The expense for these pension plans is equal to the contribution of $1,827 for the year ended March 31, 2022 (2021: $1,885). The AUC is not responsible for future funding of the plans deficit other than through contribution increases.

In addition, the AUC maintains its own defined benefit Senior Employees Pension Plan (SEPP) and two supplementary pension plans to compensate senior staff who do not participate in the government management pension plans. Retirement benefits are based on each employee's years of service and remuneration.

The effective date of the most recent actuarial funding valuation for SEPP was December 31, 2021. The accrued benefit obligation as at March 31, 2022 is based on the extrapolation of the results of this valuation. The effective date of the next required funding valuation for SEPP is December 31, 2024.

Pension plan assets are valued at market values. During the year ended March 31, 2022 the weighted average actual return on plan assets was 2.12 per cent (2021: 17.32 per cent).

Significant weighted average actuarial and economic assumptions used to value accrued benefit obligations and pension benefit costs are as follows:

	March 31, 2022	March 31, 2021
Accrued benefit obligations		
Discount rate	4.00%	3.97%
Rate of compensation increase	3.00%	3.00%
Long-term inflation rate	2.00%	2.00%

Notes to the Financial Statements

Alberta Utilities Commission
March 31, 2022
(in thousands of dollars)

Note 6 Pension (continued)

	2022	2021
Pension Benefit costs for the year		
Discount rate	3.97%	4.26%
Expected rate of return on plan assets	3.97%	4.26%
Rate of compensation increase	3.00%	3.50%

The funded status and amounts recognized in the Statement of Financial Position are as follows:

	March 31, 2022	March 31, 2021
Market value of plan assets	$ 16,717	$ 16,309
Accrued benefit obligations	15,400	15,403
Plan (deficit) surplus	1,317	906
Unamortized actuarial loss (gain)	(548)	(183)
Accrued pension asset	$ 769	$ 723

The pension benefit costs for the year include the following components:

	2022	2021
Current period benefit costs	$ 650	$ 591
Interest cost	627	639
Expected return on plan assets	(658)	(594)
Amortization of actuarial losses	15	299
	$ 634	$ 935

The average remaining service period of active employees is 6.2 years (2021: 6.2 years).

Additional information about the defined benefit pension plans is as follows:

	2022	2021
AUC contribution	$ 680	$ 1,073
Employees' contribution	156	181
Benefits paid	777	610

The asset allocation of the defined benefit pension plans' investments is as follows:

	March 31, 2022	March 31, 2021
Equity securities	46.41%	47.70%
Debt securities	16.00%	15.80%
Other	37.59%	36.50%
	100.00%	100.00%

Notes to the Financial Statements

Alberta Utilities Commission
March 31, 2022
(in thousands of dollars)

Note 7 Accounts payable and other accrued liabilities

	2022	2021
Accounts payable	$ 635	$ 334
Other accrued liabilities	1,356	1,813
Capital lease obligation	15	34
	$ 2,006	$ 2,181

Note 8 Deferred lease incentive

The AUC has received lease incentives through its office lease agreements. During 2022, the AUC did not receive any lease incentives in the form of cash and free rent (2021: $0).

	2022	2021
Opening balance	$ 4,798	$ 5,559
Cash incentive received	-	-
Rent free period received	-	-
Lease incentive amortized	(677)	(761)
Closing balance	$ 4,121	$ 4,798

Note 9 Capital assets

	March 31, 2022				March 31, 2021
	Furniture and equipment	Computer hardware and software	Leasehold improvement	Total	Total
Historical cost					
Beginning of year	$ 3,094	$ 9,226	$ 6,328	$ 18,648	$ 18,764
Additions	50	156	183	389	288
Disposals	(738)	(1,101)	(684)	(2,523)	(404)
	$ 2,406	$ 8,281	$ 5,827	$ 16,514	$ 18,648
Accumulated amortization					
Beginning of year	$ 1,310	$ 6,496	$ 2,266	$ 10,072	$ 8,613
Amortization expense	305	757	631	1,693	1,858
Effect of disposals	(486)	(1,097)	(684)	(2,267)	(399)
	$ 1,129	$ 6,156	$ 2,213	$ 9,498	$ 10,072
Net book value at March 31, 2022	**$ 1,277**	**$ 2,125**	**$ 3,614**	**$ 7,016**	**$ 8,576**
Net book value at March 31, 2021	**$ 1,784**	**$ 2,730**	**$ 4,062**	**$ 8,576**	

Notes to the Financial Statements

Alberta Utilities Commission
March 31, 2022
(in thousands of dollars)

Note 10 Accumulated surplus

Accumulated surplus is comprised of the following:

	2022			2021
	Investments in capital assets	Unrestricted surplus	Total	Total
Opening balance	$ 8,576	$ 4,326	12,902	$ 13,271
Annual operating deficit	-	(516)	(516)	(369)
Net investment in capital assets	(1,560)	1,560	-	-
Closing balance	$ 7,016	$ 5,370	$ 12,386	$ 12,902

Note 11 Contractual obligations

Contractual obligations are obligations of the AUC to others that will become liabilities in the future when the terms of those contracts or agreements are met. Contractual obligations for each of the next five years and thereafter are as follows:

	Operating leases, contracts and programs	Capital lease principal and interest payments	Total
2023	$ 2,782	$ 15	$ 2,797
2024	2,542	-	2,542
2025	2,383	-	2,383
2026	2,288	-	2,288
2027	2,141	-	2,141
Thereafter	2,279	-	2,279
	$ 14,415	$ 15	$ 14,430

Note 12 Related party transactions

Related parties are those entities consolidated or accounted for on the modified equity basis in the Government of Alberta's Consolidated Financial Statements. For the year ended March 31, 2022 the AUC received and paid $139 (2021: $121) for services from other government of Alberta organizations. The AUC had not received or provided any contributed goods or services from other government of Alberta organizations. Related parties also include key management personnel and close family members of those individuals at the AUC. There were no transactions between the AUC and its key management personnel or close family members during the year.

Note 13 Approval of financial statements

These financial statements were approved by the AUC's Chair's Management Committee.

Expenses – Detailed by Object

Alberta Utilities Commission
Year Ended March 31, 2022
Schedule 1

	2022		2021
	Budget	Actual	Actual
	(in thousands)		
Salaries, wages and employee benefits	$ 23,746	$ 20,792	$ 23,147
Supplies and services	5,931	5,370	5,551
Amortization of capital assets (Note 9)	1,800	1,693	1,858
Loss on disposal of capital assets	-	215	2
	$ 31,477	$ 28,070	$ 30,558

Salary and Benefits Disclosure

Alberta Utilities Commission
Year Ended March 31, 2022
Schedule 2

	2022				2021
	Base Salary [1]	Other Cash Benefits [2]	Other Non-cash Benefits [3]	Total	Total
	(in thousands)				
Chair of the Commission [4]	$ 332	$ 28	$ 88	$ 448	$ 763
Vice-Chair [5]	209	32	23	264	240
Vice-Chair [6]	123	68	27	218	282
Commission Member	196	47	46	289	225
Commission Member	196	22	46	264	262
Commission Member [7]	196	16	46	258	213
Commission Member	196	15	45	256	258
Commission Member [8]	181	32	43	256	207
Commission Member [9]	-	-	-	-	55
Commission Member [10]	-	-	-	-	-

(1) Includes pensionable base pay.

(2) Includes payments in lieu of vacation, health and pension benefits. No bonuses have been paid.

(3) Employer's contributions to all employee benefits including Employment Insurance, Canada Pension Plan, Alberta pension plans, health benefits, professional memberships, tuition fees and fair market value of parking. Automobiles were provided but no dollar amount included in other non-cash benefits.

(4) The position was occupied by two individuals at different times during 2021. New Chair was appointed on June 24, 2020. Severance benefits of $296 was expensed in 2021.

(5) The position was vacant from July 21, 2020 - May 31, 2021. Severance benefits of $135 was expensed in 2021.

(6) The position became vacant as of October 23, 2021.

(7) The position was vacant from July 21, 2020 - January 3, 2021. Severance benefits of $45 was expensed in 2021.

(8) The position was vacant from July 21, 2020 - January 3, 2021. Severance benefits of $45 was expensed in 2021.

(9) The position became vacant as of June 24, 2020.

(10) The position became vacant as of August 5, 2019.

Authorized Budget

Alberta Utilities Commission
Year Ended March 31, 2022
Schedule 3

	Budget (Estimate)	Authorized Changes	Authorized Budget	Actual
	(in thousands)			
Revenues				
Administration fees	$ 31,377	$ (1,000)	$ 30,377	$ 27,273
Investment income	150	-	150	37
Professional services	150	-	150	244
	31,677	(1,000)	30,677	27,554
Expenses				
Utility regulation	31,477	-	31,477	28,070
Net Capital Investment				
Capital investment	2,000	(1,000)	1,000	389
Less:				
Amortization	(1,800)	-	(1,800)	(1,693)
Net Loss on disposal	-	-	-	(215)
Proceeds on disposal of capital assets	-	-	-	(41)
	200	(1,000)	(800)	(1,560)
	$ -	$ -	$ -	$ 1,044

Note:

The Budget is based on the AUC Business Plan for the year ended March 31, 2022. The Budget and Authorized Changes have been approved by the government of Alberta.

Alberta Petroleum Marketing Commission

Consolidated Financial Statements

For the Fiscal Years Ended March 31, 2022 and 2021

Table of Contents

Auditor General OF ALBERTA

Independent Auditor's Report

To the Board of Directors of the Alberta Petroleum Marketing Commission

Report on the Consolidated Financial Statements

Opinion

I have audited the consolidated financial statements of the Alberta Petroleum Marketing Commission (the Group), which comprise the consolidated statement of financial position as at March 31, 2022, and the consolidated statements of income (loss) and comprehensive income (loss), changes in deficit, and cash flows for the year then ended, and notes to the consolidated financial statements, including a summary of significant accounting policies.

In my opinion, the accompanying consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Group as at March 31, 2022, and its financial performance, and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

Basis for opinion

I conducted my audit in accordance with Canadian generally accepted auditing standards. My responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Consolidated Financial Statements* section of my report. I am independent of the Group in accordance with the ethical requirements that are relevant to my audit of the consolidated financial statements in Canada, and I have fulfilled my other ethical responsibilities in accordance with these requirements. I believe that the audit evidence I have obtained is sufficient and appropriate to provide a basis for my opinion.

Emphasis of matter – corresponding information

I draw attention to Note 2(b) of the consolidated financial statements, which describes the change in fiscal year end. My opinion is not modified in respect to this matter.

Other information

Management is responsible for the other information. The other information comprises the information included in the *Annual Report*, but does not include the consolidated financial statements and my auditor's report thereon. The *Annual Report* is expected to be made available to me after the date of this auditor's report.

My opinion on the consolidated financial statements does not cover the other information and I do not express any form of assurance conclusion thereon.

In connection with my audit of the consolidated financial statements, my responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or my knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work I will perform on this other information, I conclude that there is a material misstatement of this other information, I am required to communicate the matter to those charged with governance.

Responsibilities of management and those charged with governance for the consolidated financial statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of the consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing the Group's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless an intention exists to liquidate or to cease operations, or there is no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Group's financial reporting process.

Auditor's responsibilities for the audit of the consolidated financial statements

My objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes my opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, I exercise professional judgment and maintain professional skepticism throughout the audit. I also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for my opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Group's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Group's ability to continue as a going concern. If I conclude that a material uncertainty exists, I am required to draw attention in my auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify my opinion. My conclusions are based on the audit

evidence obtained up to the date of my auditor's report. However, future events or conditions may cause the Group to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Group to express an opinion on the consolidated financial statements. I am responsible for the direction, supervision and performance of the group audit. I remain solely responsible for my audit opinion.

I communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that I identify during my audit.

[Original signed by W. Doug Wylie FCPA, FCMA, ICD.D]
Auditor General

June 3, 2022
Edmonton, Alberta

Consolidated Statements of Financial Position

Alberta Petroleum Marketing Commission

(Expressed in thousands of Canadian dollars)

As at ($000s)	Note	**March 31, 2022**	March 31, 2021
			Note 2(b)
ASSETS			
Cash and cash equivalents	7	**26,701**	195,180
Restricted cash	8	**72,568**	11,282
Accounts receivable	9	**656,041**	401,978
Inventory	10	**95,704**	51,711
Term loan receivable	12	**—**	39,776
Total current assets		**851,014**	699,927
Investment in North West Redwater Partnership	6	**250,601**	—
Corporate assets	11	**599**	—
Software development	13	**7,717**	8,781
Investment in KXL Expansion Project	14	**82,000**	106,000
Inventory	10	**6,877**	6,877
Term loan receivable	12	**—**	499,577
Total assets		**1,198,808**	1,321,162
LIABILITIES			
Accounts payable and accrued liabilities	15	**548,310**	475,952
Due to the Department of Energy	16	**218,949**	58,642
Short term debt	17	**2,031,427**	1,896,639
Accrued interest payable	18	**7,554**	3,001
Contingent consideration	19	**3,590**	—
Lease liabilities	11	**52**	—
KXL Expansion Project Debt Guarantee	21	**—**	1,035,002
Sturgeon Refinery Processing Agreement provision	23	**299,000**	550,000
Total current liabilities		**3,108,882**	4,019,236
Long term debt	20	**427,493**	—
Contingent consideration	19	**193,628**	—
Lease liabilities	11	**394**	—
Sturgeon Refinery Processing Agreement provision	23	**51,000**	1,944,000
Total liabilities		**3,781,397**	5,963,236
SHAREHOLDERS' DEFICIT			
Deficit		**(2,582,589)**	(4,642,074)
Total liabilities and shareholders' deficit		**1,198,808**	1,321,162

Commitments note 25
Subsequent event note 32

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements of Income (Loss) and Comprehensive Income (Loss)

Alberta Petroleum Marketing Commission

(Expressed in thousands of Canadian dollars)

($000s)	Note	**Twelve Months ended March 31, 2022**	Fifteen Months ended March 31, 2021
			Note 2(b), 2(f)
REVENUES			
Refinery sales		**2,381,861**	999,251
Other revenue	22	**71,250**	—
Marketing fee revenue		**11,201**	5,256
		2,464,312	1,004,507
Finance income		**26,538**	55,703
		2,490,850	1,060,210
EXPENSES			
Refinery feedstock purchases		**1,759,753**	777,111
Refinery tolls		**804,055**	837,150
General and administrative	28	**13,062**	18,940
Depreciation and amortization	11, 13	**1,110**	1,331
(Gain) loss on foreign exchange		**(3,574)**	36,825
Finance costs		**88,663**	179,983
Income from North West Redwater Partnership	6	**(2,611)**	—
Provisions for Sturgeon Refinery	23, 24	**(2,218,622)**	603,916
KXL Expansion Project Debt Guarantee loss allowance	21	**—**	1,035,002
Fair value (gain) loss on investment in KXL Expansion Project	14	**(10,471)**	255,831
Total expenses		**431,365**	3,746,089
Net income (loss) and comprehensive income (loss) before income taxes		**2,059,485**	(2,685,879)
Income taxes	26	**—**	(5,199)
Net income (loss) and comprehensive income (loss) after income taxes		**2,059,485**	(2,691,078)

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements of Cash Flows

Alberta Petroleum Marketing Commission

(Expressed in thousands of Canadian dollars)

($000s)	Note	**Twelve Months ended March 31, 2022**	Fifteen Months ended March 31, 2021
OPERATING ACTIVITIES			**Note 2(b), 2(f)**
Net income (loss) and comprehensive income (loss)		**2,059,485**	(2,691,078)
Adjusted for items not involving cash			
Accrued interest on term loan receivable	12	**(26,326)**	(55,275)
Amortization of premium on long term debt	20	**(7,860)**	—
Depreciation and amortization		**1,110**	1,331
Accretion expense	19, 23	**79,818**	163,590
Fair value (gain) loss on investment in KXL Expansion Project	14	**(10,471)**	255,831
Unrealized foreign exchange (gain) loss		**(3,324)**	42,512
Income from North West Redwater Partnership	6	**(2,611)**	—
Change to loss provision for accounts receivables	24	**(63)**	534
Change in loss allowance for KXL Expansion Project Debt Guarantee	21	**—**	1,035,002
Change to loss provision for Sturgeon Refinery Processing Agreement	23	**(2,218,355)**	603,410
Change to long term inventory		**—**	(6,877)
Interest received from term loan receivable	12	**251,486**	43,772
Changes in accrued interest payable	18	**4,553**	(4,914)
Changes in non-cash working capital	31	**(127,155)**	32,595
Net cash provided by (used in) operating activities		**287**	(579,567)
FINANCING ACTIVITIES			
Payment of lease liabilities	11	**(32)**	—
Proceeds from short term debt	17	**2,487,156**	1,703,236
Repayment of short term debt	17	**(1,917,015)**	(661,640)
Net cash provided by financing activities		**570,109**	1,041,596
INVESTING ACTIVITIES			
Transaction costs attributable to acquiring partnership interest	6	**(56,235)**	—
Funds from term loan receivable	12	**314,734**	124,079
Liquidation proceeds received on KXL investment	14	**37,795**	—
Divestment of KXL Expansion Project - US Class A Interests	14	**—**	631,781
Debt guarantee payment for KXL Expansion Project	21	**(1,035,002)**	—
Expenditures on office equipment and improvements	11	**(167)**	—
Investment in KXL Expansion Project		**—**	(1,036,124)
Net cash used in investing activities		**(738,875)**	(280,264)
Net change in cash and cash equivalents		**(168,479)**	181,765
Cash and cash equivalents, beginning of period		**195,180**	13,415
Cash and cash equivalents, end of period		**26,701**	195,180
Cash paid:			
Interest received		**251,698**	44,200
Interest paid		**(12,152)**	(21,307)
Taxes		**(4,327)**	(825)

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements of Changes in Deficit

Alberta Petroleum Marketing Commission

(Expressed in thousands of Canadian dollars)

($000s)	**Twelve Months ended March 31, 2022**	Fifteen Months ended March 31, 2021
		Note 2(b)
Deficit, beginning of period	**(4,642,074)**	(1,950,996)
Net income (loss) and comprehensive income (loss)	**2,059,485**	(2,691,078)
Deficit, end of period	**(2,582,589)**	(4,642,074)

The accompanying notes are an integral part of these consolidated financial statements.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

1. AUTHORITY AND STRUCTURE

The Alberta Petroleum Marketing Commission ("APMC" or the "Commission") is a corporation created under the *Petroleum Marketing Act* (Alberta) to act as agent for the Government of Alberta ("GOA" or "Crown") in accepting delivery and dealing with the Crown's royalty share of hydrocarbons; and engaging in other hydrocarbon-related activities in a manner that is in the public interests of Albertans. Under this mandate, the APMC performs commercial activities to receive and market crude oil royalty volumes on behalf of the Crown, and to transact or invest in energy projects which seek to expand access to global energy markets or otherwise maximize the long-term sustainable value of the Crown's resources. The Commission is overseen by a majority-independent Board of Directors and operates at arm's length from the GOA; however, it is accountable to and may receive policy and other direction from the Alberta Minister of Energy. The consolidated financial statements disclose the transactions the APMC incurs while marketing crude oil on behalf of the Crown, and the APMC's investment in the North West Redwater Partnership ("NWRP" or the "Partnership"), the Sturgeon Refinery ("Refinery"), and the KXL Expansion Pipeline ("KXL Expansion Project") through newly created subsidiaries in 2020.

The Commission operates a Business Development group to identify and analyze business ideas and proposals that provide strategic value to Alberta and are financially feasible.

As an agent of the GOA, the Commission is not subject to Canadian federal or provincial corporate income taxes.

The Commission is located at the following address: 1050, 250 – 5 Street S.W., Calgary, Alberta, T2P 0R4. These consolidated financial statements were authorized for issue by the Board of Directors on June 3, 2022.

The Commission conducts its principal business in four reportable operating segments (note 30).

2. BASIS OF PRESENTATION

(a) Statement of compliance

The consolidated annual financial statements (the "Annual Financial Statements") have been prepared in accordance with International Financial Reporting Standards (IFRS) as published by the International Accounting Standards Board (IASB) and related interpretations as issued by the IFRS Interpretations Committee (IFRIC).

(b) Change in reporting period

The Lieutenant Governor in Council prescribed a change in year end for the Commission from December 31 to March 31 under an Order in Council (O.C. 052/2021). The previous Annual Financial Statements presented the Commission's financial position as at March 31, 2021 and the results of its operations and changes in its financial position for the fifteen month period then ended. As such, amounts in the annual consolidated financial statements for the year ended March 31, 2022 will not be entirely comparable to those for the fifteen months period ended March 31, 2021. The comparative periods presented in the Consolidated Statements of Income (Loss) and Comprehensive Income (Loss) include the respective periods for the new fiscal year end adopted.

(c) Basis of measurement

The Annual Financial Statements have been prepared on a historical cost basis except for the Investment in KXL Expansion Project that has been measured at fair value.

(d) Functional and presentation currency

The Annual Financial Statements are presented in Canadian dollars (CAD), which is also the APMC's functional and presentation currency.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission
For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021
(Expressed in thousands of Canadian dollars, unless stated otherwise)

(e) Use of estimates, assumptions and judgements

The preparation of the Annual Financial Statements in conformity with IFRS requires management to make judgements, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Significant estimates and judgments used in the preparation of the Annual Financial Statements are described in note 4.

(f) Comparative figures

Certain comparative figures on the Consolidated Statements of Income (Loss) and Comprehensive Income (Loss) and the Consolidated Statements of Cash Flows have been restated to conform to the current period's presentation.

3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently to all periods presented in the Annual Financial Statements.

(a) Basis of consolidation

The Annual Financial Statements include the accounts of the APMC and its wholly owned subsidiaries. Subsidiaries are consolidated from the date the Commission obtains control and continues to be consolidated until the date such control ceases. Control is achieved when the APMC is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Some of the APMC's subsidiaries have a December 31st year end for statutory purposes, however, the results of the subsidiaries are prepared for the same reporting period as the APMC, using consistent accounting policies. All inter-entity transactions have been eliminated upon consolidation between the APMC and its subsidiaries in these Annual Financial Statements. The APMC's operations are viewed as four operating segments by the chief executive officer of the Commission for the purpose of resource allocation and assessing performance.

The following table details the APMC's subsidiaries:

Name	Principal activities	Country of Incorporation	% Equity Interest
2254737 Alberta Ltd. [1]	Facilitate APMC's financial support of the Canadian portion of the KXL Expansion Project and assist with various governance related matters	Canada	100%
2254755 Alberta Ltd. [1]	Facilitate APMC's financial support for the project costs related to the Canadian portion of the KXL Expansion Project	Canada	100%
2254753 Alberta Ltd. [1]	Facilitate APMC's financial support for the project costs related to the US portion of the KXL Expansion Project and assist with various governance related matters	Canada	100%
2254746 Alberta Ltd.[1,2]	Facilitate APMC's financial support for the project costs related to the US portion of the KXL Expansion Project	Canada	100%
2254746 Alberta Sub. Ltd. [1]	Facilitate APMC's financial support for the project costs related to the US portion of the KXL Expansion Project	USA	100%
APMC (Redwater) L.P.	Holds a 50% interest in the North West Redwater Partnership	Canada	100%
APMC (Redwater) Corp.	General partner in APMC (Redwater) L.P.	Canada	100%

1. Denotes subsidiaries with a December 31 year end.
2. 2254746 Alberta Ltd. Is the sole shareholder of 2254746 Alberta Sub. Ltd.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

(b) Joint arrangements

Joint arrangements represent arrangements in which two or more parties have joint control established by a contractual agreement. Joint control only exists when decisions about the activities that most significantly affect the returns of the investee are unanimous. Joint arrangements can be classified as either a joint operation or a joint venture. The classification of joint arrangements requires judgment. In determining the classification of its joint arrangements, the Commission reviews numerous criteria including the contractual rights and obligations of each investor, whether the legal structure of the joint arrangement gives the entity direct rights to the assets and obligations for the liabilities, and whether substantially all of the economic output and benefit is to be received by the parties over the estimated economic life of the asset.

Where the APMC has rights to the assets and obligations for the liabilities of a joint arrangement, such arrangement is classified as a joint operation and the Commission’s proportionate share of the joint operation’s assets, liabilities, revenues and expenses are included in the consolidated financial statements, on a line-by-line basis.

Where the APMC has rights to the net assets of an arrangement, the arrangement is classified as a joint venture and accounted for using the equity method of accounting. Under the equity method, the Commission's initial investment is recognized at cost and subsequently adjusted for the APMC’s share of the joint venture’s income or loss, less distributions received. When the APMC transacts with a joint venture, profits and losses resulting from the transactions are recognized in the Commission’s financial statements only to the extent of interests in the joint venture that are not related to the APMC. Should the Commission’s share of losses of a joint venture exceed APMC’s interest in that joint venture, the Commission discontinues recognizing its share of further losses. Additional losses are recognized only to the extent that the APMC has incurred legal or constructive obligations or made payments on behalf of the joint venture.

An investment in a joint venture is accounted for using the equity method from the date on which the APMC obtains joint control in the investee. On acquisition of the investment in a joint venture, any excess of the cost of the investment over the APMC’s share of the net fair value of the identifiable assets and liabilities of the investee is recognized as goodwill, which is included within the carrying amount of the investment. Any excess of the APMC’s share of the net fair value of the identifiable assets and liabilities over the cost of the investment is recognized immediately in the Consolidated Statements of Income (Loss) and Comprehensive Income (Loss) in the period in which the investment is acquired.

The APMC assesses whether there is objective evidence that the interest in a joint venture may be impaired. When any objective evidence exists, the investment is tested for impairment as a single asset by comparing its recoverable amount (higher of value in use and fair value less costs of disposal) with its carrying amount. Any reversal of impairment losses are recognized to the extent that the recoverable amount of the investment subsequently increases.

(c) Foreign currencies

The Commission’s Annual Financial Statements are presented in Canadian dollars, which is also the functional and presentation currency of its subsidiaries. Functional currencies of the Commission’s individual entities are the currency of the primary economic environment in which the entity operates. Transactions in foreign currencies are translated to the appropriate functional currency at foreign exchange rates that approximate those on the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the appropriate functional currency at foreign exchange rates as at the balance sheet date. Foreign exchange differences arising on translation are recognized in the Consolidated Statements of Income (Loss) and Comprehensive Income (Loss). Non-monetary assets that are measured in a foreign currency at historical cost are translated using the exchange rate at the date of the transaction. Non-monetary items measured at fair value in a foreign currency are translated using the exchange rate at the date when the fair value is determined.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

(d) Cash and cash equivalents

Cash and cash equivalents consist primarily of cash in banks, term deposits, certificates of deposit and all other highly liquid investments at the time of purchase.

(e) Inventory

Inventory is maintained to support APMC's operations at the Sturgeon Refinery. Inventory is comprised of blended feedstock, intermediates and products. Products include synthetic crude oil, intermediate products, ultra-low sulphur diesel, unconverted oil, liquefied petroleum gas, diluent and sulphur, including pipeline linefill and tank heels. Product inventories are carried at the lower of cost and net realizable value. APMC contracts with third parties to directly deliver its share of feedstock supply to the Refinery. The cost of APMC’s share of feedstock is the invoiced amount from those third parties. Net realizable value methodology for blended feedstock, intermediates and products uses a combination of weighted average index prices and actual sales prices. If the carrying amount exceeds net realizable value, a write-down is recognized.

As part of the marketing activities, inventory of $5.2 million (March 31, 2021 - $0.6 million) is being held in a fiduciary capacity on behalf of the Department of Energy ("DOE"). Inventory represents the royalty oil in feeder and trunk pipelines and consists of both purchased oil and royalty share oil. The Commission purchases oil to fulfill pipeline and quality requirements as part of the conventional crude oil marketing activities. As the Commission does not hold title to the oil and will not benefit from the ultimate sale as a principal, this inventory is not recognized.

(f) Office equipment and improvements

Office equipment and improvements are carried at cost less accumulated depreciation and accumulated impairment losses.

The initial cost of an asset comprises its purchase price and costs directly attributable to bringing the asset to the location and condition necessary for its intended use.

The Commission is depreciating its office furniture and equipment and leasehold improvements over a period of five years.

(g) Software development assets

The Commission has internally developed operations software to handle actualization and settlement of royalty and marketing transactions. In addition, APMC purchased accounting software for reporting and financial settlement of transactions.

These software related assets are amortized on a straight-line basis over the estimated useful life of the software. The software systems have an estimated useful life of 10 years.

(h) Impairment of long-lived assets

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of the asset may not be recoverable. In addition, an annual review is performed. Assets are grouped at the lowest level where there are separately identifiable cash inflows for the purpose of assessing impairment.

If there is an indication of impairment, the asset’s recoverable amount is estimated. The recoverable amount is the greater of an asset’s fair value less cost to sell and its value in use, if the carrying amount of the asset exceeds the recoverable amount, an impairment loss is recognized. Impairment losses are recognized in the Consolidated Statements of Income (Loss) and Comprehensive Income (Loss).

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

If the circumstances leading to the impairment are no longer present, an impairment loss may be reversed related to the software development assets. The extent of the impairment loss that can be reversed is determined by the carrying cost net of amortization that would have existed if the impairment had not occurred. Therefore, reversal of the loss cannot exceed the total carrying cost less amortization of the asset had the impairment not occurred. The impairment loss reversals are recognized in the Consolidated Statements of Income (Loss) and Comprehensive Income (Loss).

(i) ***Right-of-use assets and liabilities***

At inception of a contract, an assessment is performed to assess whether a contract is, or contains a lease. A contract is, or contains a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. To assess whether a contract conveys the right to control the use of an identified asset, an assessment is performed to determine whether: the contract involves the use of an identified asset; has the right to obtain substantially all of the economic benefits from the use of the asset throughout the period of use; and, has the right to direct the use of the asset.

A right-of-use asset and a lease liability is recognized at the commencement date of the lease contract, which is the date that the right-of-use asset is available. The right-of-use asset is initially measured at cost. The cost of a right-of-use asset includes the amount of the initial measurement of the lease liability, lease payments made prior to the commencement date, initial direct costs and estimates of the asset retirement obligation, if any. Subsequent to initial recognition, the right-of-use asset is depreciated using the straight-line method over the earlier of the end of the useful life of the right-of-use asset or the lease term.

Lease liabilities are initially measured at the present value of lease payments discounted at the rate implicit in the lease, or if not readily determinable, the Commission's incremental borrowing rate. Lease payments include fixed lease payments, variable lease payments based on indices or rates, residual value guarantees and purchase options expected to be exercised. Subsequent to initial recognition, the lease liability is measured at amortized cost using the effective interest method. Lease liabilities are re-measured if there are changes in the lease term or if the Commission changes its assessment of whether it is reasonably certain it will exercise a purchase, extension or termination option. Lease liabilities are also re-measured if there are changes in the estimate of the amounts payable under the lease due to changes in indices or rates, or residual value guarantees.

(j) ***Revenue from contracts with customers***

Revenue from contracts with customers is recognized when or as APMC satisfies a performance obligation by transferring a promised good or service to a customer. For marketing activities, the Commission earns revenue through marketing fees charged to the DOE based on net volumes sold. Collection of revenue occurs on or about the 25^{th} of the month following delivery. Marketing fees are recognized when earned which corresponds to the service period in which the conventional crude oil marketing activities take place.

The Sturgeon Refinery achieved the Commercial Operations Date (“COD”) as of June 1, 2020. Revenue from product sales is recognized when performance obligations in the sales contracts are satisfied and it is probable that the Commission will collect the consideration to which it is entitled. Performance obligations are satisfied at the point in time when the product is lifted from the Refinery facility and control passes to the customer. The customers are assessed for creditworthiness before entering into contracts and throughout the revenue recognition process. The larger contracts for the sale of products generally have terms of greater than a year. There are also spot deals and contracts less than a year. Revenues are typically collected in the current month or the following month.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

(k) Financial instruments

(i) Financial assets:

The Commission classifies its financial assets in the following categories: measured at amortized cost, fair value through other comprehensive income ("FVTOCI") and fair value through profit or loss ("FVTPL"). The classification is made at initial recognition and depends on the Commission's business model for managing financial assets and the contractual terms of the cash flows. In order for a financial asset to be classified and measured at amortized cost or FVTOCI, it needs to give rise to cash flows that are solely payments of principal and interest ("SPPI") on the principal amount outstanding. This assessment is referred to as the SPPI test and is performed at an instrument level. Financial assets with cash flows that are not SPPI are classified and measured at fair value through profit or loss, irrespective of the business model.

The Commission's business model for managing financial assets refers to how it manages its financial assets in order to generate cash flows. The business model determines whether cash flows will result from collecting contractual cash flows, selling the financial assets, or both. Financial assets classified and measured at amortized cost are held within a business model with the objective to hold financial assets in order to collect contractual cash flows while financial assets classified and measured at FVTOCI are held within a business model with the objective of both holding to collect contractual cash flows and selling.

Subsequent measurement of financial instruments is based on their initial classifications. The Commission does not currently have any financial assets classified or measured at FVTOCI.

Financial assets at amortized cost:

The Commission classifies cash and cash equivalents, cash held in trust and accounts receivable as financial assets at amortized cost. Amortized cost is defined as the amount at which the financial asset is measured at initial recognition minus the principal repayments, plus or minus the cumulative amortization using the effective interest rate ("EIR") method of any difference between the initial amount and the maturity amount and, for financial assets, as adjusted for any loss allowance. Gains and losses are recognized in the Consolidated Statements of Income (Loss) and Comprehensive Income (Loss) when the asset is derecognized, modified or impaired.

Financial assets at FVTPL:

The Commission has determined that it does not have control, joint control or significant influence over its Investment in the KXL Expansion Project Class A and C Interests and this investment does not meet the SPPI test, despite the Class A Interests earning a return in the form of accretion income (note 14). Therefore, the Commission measures the Investment in KXL Expansion Project at FVTPL. Financial assets at FVTPL are carried in the Consolidated Statement of Financial Position at fair value with net changes in fair value recognized in the Consolidated Statements of Income (Loss) and Comprehensive Income (Loss).

Impairment:

The Commission's accounting policy for impairment of financial assets is as follows: at each reporting date, on a forward looking basis, the Commission assesses the expected losses associated with its financial assets carried at amortized cost. For trade accounts receivable, the simplified approach permitted by IFRS 9 is applied, which requires expected lifetime credit losses to be recognized from initial recognition of the receivable. To measure expected credit losses, accounts receivable are grouped based on the counterparty investment rating as reported by the credit rating agencies and an anticipated default rate is applied to each rating multiplied by the receivable balance outstanding at a reporting date. For counterparties not rated by the credit rating agencies, the simplified approach and a provision matrix will be used to calculate the impairment provision. The matrix would look at a different percentage applied against each aging category,

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

including the current amounts. The internal and external credit rating of a counterparty will be considered as part of this overall process.

Credit risk for longer term receivables is assessed based on an external credit rating of the counterparty. For longer term receivables with credit risk that has not increased significantly since the date of recognition, the Commission measures the expected credit loss as the 12 month expected credit loss.

Changes in the provision for expected credit loss are recognized on the Consolidated Statement of Income (Loss) and Comprehensive Income (Loss).

The Commission considers a financial asset to be in default when contractual payments are 90 days past due. However, in certain cases, the Commission may also consider a financial asset to be in default when internal or external information indicates that APMC is unlikely to receive the outstanding contractual amounts in full before taking into account any credit enhancements held. A financial asset is written off when there is no reasonable expectation of recovering the contractual cash flows.

(ii) Financial liabilities:

Financial liabilities are classified, at initial recognition, as financial liabilities at FVTPL, loans and borrowings, payables, as appropriate.

All financial liabilities are recognized initially at fair value and, in the case of loans and borrowings and payables, net of directly attributable transaction costs. The Commission's financial liabilities include accounts payable, due to Department of Energy, short term and long term debt, and accrued interest payable.

For purposes of subsequent measurement, financial liabilities are classified in two categories:

- financial liabilities at FVTPL;
- financial liabilities at amortized cost.

All of the Commission's financial liabilities are subsequently measured at amortized cost using the EIR method. Gains and losses are recognized in profit or loss when the liabilities are derecognized as well as through the EIR amortization process.

(iii) Fair value measurement:

The Commission measures financial instruments such as the Investment in the KXL Expansion Project at fair value at each Consolidated Statement of Financial Position date.

Fair value 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. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place either:

- In the principal market for the asset or liability; or
- In the absence of a principal market, in the most advantageous market for the asset or liability.

The principal or the most advantageous market must be accessible by the Commission. The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset in its highest and best use or by selling it to another market participant that would use the asset in its highest and best use.

The Commission uses valuation techniques that are appropriate in the circumstances and for which sufficient data are available to measure fair value, maximizing the use of relevant observable inputs and minimizing the use of unobservable inputs.

All assets and liabilities for which fair value is measured or disclosed in the consolidated financial statements are categorized within the fair value hierarchy, described as follows, based on the lowest level input that is significant to the fair value measurement as a whole:

- Level 1 - Quoted (unadjusted) market prices in active markets for identical assets or liabilities.
- Level 2 - Valuation techniques for which the lowest level input that is significant to the fair value measurement is directly or indirectly observable.
- Level 3 - Valuation techniques for which the lowest level input that is significant to the fair value measurement is unobservable.

For assets and liabilities that are recognized in the Annual Financial Statements at fair value on a recurring basis, the Commission determines whether transfers have occurred between levels in the hierarchy by re-assessing categorization (based on the lowest level input that is significant to the fair value measurement as a whole) at the end of each reporting period.

The Commission determines the policies and procedures for fair value measurement. External valuation specialists may be utilized in the valuation of significant assets, such as the Investment in the KXL Expansion Project. Involvement of external valuation specialists is decided upon annually by senior management of APMC. Selection criteria include market knowledge, reputation, independence and whether professional standards are maintained. The Commission decides, after discussions with the external valuation specialists, which valuation techniques and inputs to use in the measurement of fair value.

At each reporting date, senior management reviews the values of assets and liabilities that are required to be re-measured or re-assessed as per the Commission’s accounting policies. When estimating the fair value, the Commission develops key assumptions based on objective observable data, to the extent possible, and agrees major inputs to contracts and other relevant documents.

The Commission compares the key assumptions and major input used in the determination of the fair value of each asset and liabilities to relevant external sources when available.

At each reporting period, the Commission presents the valuation results to the Board. This includes a discussion of the major assumptions used in the valuations.

For the purpose of fair value disclosures, the Commission has determined classes of assets and liabilities on the basis of the nature, characteristics and risks of the asset or liability and the level of the fair value hierarchy, as explained above.

(iv) Financial guarantee contracts:

Financial guarantee contracts are contracts issued by APMC that contingently require the Commission to make specified payments to reimburse the holder for a loss it incurs because the specified debtor fails to make payment when due in accordance with the terms of a debt instrument. The date the Commission becomes a party to the irrevocable commitment is the date of initial recognition. Financial guarantee contracts are initially recognized and measured at the fair value of the obligation undertaken in issuing the guarantee, which is generally equal to the guarantee fee received in advance (if any), adjusted for transaction costs that are directly attributable to the issuance of the guarantee. Subsequently, the guarantee is

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

recognized as a liability measured at the higher of (i) the amount initially recognized (if any) less amortization for the passage of time and (ii) the loss allowance measured using an expected credit loss (“ECL”) model.

ECLs with respect to financial guarantee contracts are calculated using a probability of default approach and are based on the difference between the contractual cash flows due in accordance with the contract and all the cash flows that the Commission expects to receive in respect of entitlement to contractual recoveries or reimbursements (but excluding expected guarantee fees or premiums), discounted at an approximation of the current rate representing the risk of cash flows.

ECLs are recognized in two stages. For credit exposures for which there has not been a significant increase in credit risk since initial recognition, ECLs are provided for credit losses that result from default events that are possible within the next 12 months (a 12-month ECL). For those credit exposures for which there has been a significant increase in credit risk since initial recognition, a loss allowance is required for credit losses expected over the remaining life of the exposure, irrespective of the timing of the default (a lifetime ECL). Any changes in the recognized liability is included in income. In assessing whether there has been a significant increase in the credit risk since initial recognition, the Commission considers the changes in the risk that the specified debtor will default on the contract.

(l) Provisions and onerous contracts

Provisions

Provisions, including contingent consideration, are recognized when the Commission has a present legal or constructive obligation as a result of past events, it is probable that an outflow of resources will be required to settle the obligation, and the amount has been reliably estimated. Provisions are not recognized for future operating losses. Provisions are measured at the present value of the expenditures expected to be required to settle the obligation using a rate that reflects current market assessments of the time value of money and the risks specific to the obligation. The increase in the provision due to passage of time is recognized as interest expense.

Onerous contracts

At each year-end, APMC performs an onerous contract assessment. A provision for an onerous contract is recorded when the unavoidable costs of meeting an obligation under a contract exceed the economic benefits expected to be received under it. APMC uses an incremental cost approach to determine the costs of fulfilling obligations under a contract. Where a provision is required, it is measured as the net present value of the unavoidable net cash flows, and is recorded as an expense on the Consolidated Statement of Income (Loss) and Comprehensive Income (Loss) and offsetting liability on the Consolidated Statement of Financial Position.

For each subsequent year-end, the Commission will perform an assessment to determine if the contract remains onerous, and if so, update the provision accordingly.

The balance sheet provision will be adjusted each year to the new net present value (either higher or lower) with the offset being recorded through the Consolidated Statements of Income (Loss) and Comprehensive Income (Loss). If the contract is no longer onerous, then the provision is reversed in its entirety (i.e. the contract cannot become an asset).

(m) Finance income and finance expenses

Finance income generated from conventional crude oil marketing operations comprises interest income earned on cash and cash equivalents.

Finance income related to the Sturgeon Refinery is comprised of interest income earned on the term loan receivable and interest income earned daily on cash and cash equivalents.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

Finance expenses consist of interest expense on debt obligations, net of the unwinding of premiums recognized on the issuance of debt, and accretion expense on Surgeon Refinery Processing Agreement provision.

(n) Income taxes

As stated in Note 1 above, the Commission is exempted from Canadian federal and provincial corporate income taxes. However, 2254746 Alberta Sub Ltd., a Delaware incorporated company and 2254746 Alberta Ltd., an Alberta incorporated company have exposure to US federal and state corporate income taxes.

Current income tax

Current income tax assets and liabilities are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted or substantively enacted at the reporting date in the country in which the Commission generates taxable income.

Current income tax relating to items recognized directly in equity is recognized in equity and not in profit or loss. Management periodically evaluates positions taken in the tax returns with respect to situations in which applicable tax regulations are subject to interpretation and establishes provisions where appropriate.

Deferred tax

Deferred tax is accounted for using the liability method on temporary differences between the tax basis of assets and liabilities and their carrying value for financial reporting purposes as at the reporting date.

Deferred tax assets are recognized for all deductible temporary differences, the carry forward of unused tax credits, and any unused tax losses. Deferred tax assets are recognized to the extent that it is probable that taxable income will be available against which the deductible temporary differences, the carry forward of unused tax credits, or the unused tax losses can be utilized.

Deferred tax is not recognized for:

- Temporary differences on the initial recognition of assets or liabilities in a transaction that is not a business combination and that affects neither the accounting nor taxable profit or loss;

- Taxable temporary differences arising on the initial recognition of goodwill; and
- Temporary differences related to investments in subsidiaries and joint ventures to the extent that is probable that they will not reverse in the foreseeable future.

The carrying amount of deferred tax assets is reviewed at each reporting date and reduced to the extent that it is no longer probable that taxable income will be available to allow all or part of the deferred tax asset to be utilized. Unrecognized deferred tax assets are re-assessed at each reporting date and are recognized to the extent that it has become probable that future taxable income will allow the deferred tax asset to be recovered.

Deferred tax liabilities are recorded for all temporary differences other than where the temporary difference arises from the initial recognition of goodwill.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the year when the asset is realized or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the reporting date.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

Deferred tax assets and deferred tax liabilities are offset if a legally enforceable right exists to set off current tax assets against current tax liabilities and the deferred taxes relate to the same taxable entity and the same taxation authority.

4. SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGEMENTS

The preparation of these Annual Financial Statements in conformity with IFRS requires the Commission to make judgements, estimates and assumptions that affect the reported amounts of assets, liabilities, and the disclosure of contractual obligations and contingencies, if any, at the date of the Annual Financial Statements and reported amounts of revenues and expenses during the period. Estimates are subject to measurement uncertainty and changes in such estimates in future years could require a material change in the Annual Financial Statements. Estimates and judgements are continuously evaluated and based on the Commission's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Actual results may differ from these estimates. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future period affected.

For the year ended March 31, 2022, COVID-19 continued to have an impact on the global economy, including the oil and gas industry. Business conditions in the past year continued to reflect the market uncertainty associated with COVID-19. The Commission has taken into account the impacts of COVID-19 and the unique circumstances it has created in making estimates, assumptions and judgements in the preparation of these consolidated financial statements, and continues to monitor the developments in the business environment and commodity market. Estimates and judgements made by the Commission in the preparation of the Annual Financial Statements are increasingly difficult and subject to a higher degree of measurement uncertainty during this volatile period.

The following are judgements, estimates and assumptions that the Commission has made in the process of applying APMC's accounting policies and that have the most significant effect on the amounts recognized in these Annual Financial Statements.

(a) Government business enterprise

Under public sector accounting standards, organizations which are controlled by the government are either government business enterprises or other government organizations. Government business enterprises are required to apply IFRS, whereas other government organizations are provided with a choice for basis of presentation. The Commission has exercised judgment and determined that it is a government business enterprise because it is a separate legal entity and has been delegated financial and operational authority to carry on a business. In 2013, the Commission's mandate was expanded, and it is expected through its involvement with other marketing activities, such as the Sturgeon Refinery and KXL Expansion Project that it can provide services, maintain its operations and meet liabilities from sources outside of the government reporting entity. Had the Commission not been determined to be a government business enterprise, the Commission would have continued to apply public sector accounting standards, and such an alternative basis of accounting could have a pervasive effect on the measurement and presentation of items in the Annual Financial Statements.

(b) Revenue recognition

The Commission has exercised judgment in determining whether it is acting as a principal or agent with respect to conventional crude oil marketing activities. The Commission is providing services to the Crown as delegated in the Petroleum Marketing Act that are "…in the public interest of Alberta". The Commission accepts delivery of and markets the Crown's royalty share of crude oil, and has the ability to determine which customers to transact with, and whether it should purchase additional product for blending activities to change the composition of crude oil sold. Under the *Petroleum Marketing Act,* the Commission has the responsibility for ensuring the crude oil meets the customers' specifications and for the establishment of prices. However, the Commission does not have the ability to direct the use of the crude oil, as the use is mandated by the Crown via the *Petroleum Marketing Act*. The Commission remits the net proceeds from the sale of product to the DOE, and therefore does not have the ability to obtain the benefits from the crude oil. As the APMC does not

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

direct the use of the crude oil, nor obtain the economic benefits from it, management has determined that it does not have control and is therefore an agent with respect to the conventional crude oil marketing activities. Therefore, the gross inflows and economic benefits of conventional crude oil marketing activities are considered collected on behalf of the DOE and are not recognized as revenue.

APMC has used judgment in determining whether it is acting as a principal or agent with respect to crude-by-rail activities. APMC was directed, on May 24, 2019, "…take all steps possible to explore best options for assigning crude-by-rail program contracts entered into by the Commission to third parties, and to enter into assignment agreements as expeditiously as possible with third parties on commercial terms, provided that the final terms have been approved by the Government". While the Commission entered into the contracts, it was acting as agent on behalf of the Crown and all financial risk belongs to the Crown. Therefore, the gross inflows and economic benefits of the crude-by-rail program are considered collected on behalf of the Crown and are not recognized as revenue.

APMC has also exercised judgment in determining whether it is acting as a principal or agent with respect to Sturgeon Refinery tollpayer activities. As part of the processing agreement, NWRP processes the feedstock provided by APMC and CNRL (collectively, the "Tollpayers") into refined products and will sell the refined products and by-products on behalf of APMC and CNRL. APMC and CNRL take the financial responsibility for the refined products and by-products meeting customer specifications, inventory risk, and establishing prices for the products. Therefore, APMC is acting as the principal in this arrangement and the gross inflows and economic benefits of the Sturgeon Refinery activities are recognized as revenue.

(c) Interests in Sturgeon Refinery

Prior to closing of the optimization transaction on June 30, 2021 (note 6), APMC's interest in the Sturgeon Refinery was as follows:

NWRP was a general partnership formed by CNR (Redwater) Limited (formerly Canadian Natural Upgrading Limited) ("CNR Redwater"), a wholly-owned subsidiary of CNRL and by NWU LP, an indirect wholly-owned subsidiary of North West Refining Inc. ("NWU LP"). NWRP was formed under the Partnership Act (Alberta) pursuant to a partnership agreement dated February 15, 2011, as amended on November 7, 2012, March 11, 2013 and April 7, 2014. The partners each had a 50 percent partnership interest in NWRP.

NWRP had entered into various agreements to construct and operate the Sturgeon Refinery, a facility 45 kilometres north-east of Edmonton which has the capacity to process approximately 50,000 barrels per day (bbl/d) of bitumen at an incurred facility capital cost ("FCC") of $10.0 billion. APMC is providing the Sturgeon Refinery with 37,500 bbl/d of bitumen feedstock and Canadian Natural Resources Partnership will provide the remaining 12,500 bbl/d of bitumen feedstock under a former 30 year cost-for-service tolling agreements (collectively, the Processing Agreements). The Sturgeon Refinery achieved its COD on June 1, 2020.

Effective the completion of the optimization transactions for the Sturgeon Refinery, as disclosed in note 6, APMC now owns a 50 percent partnership interest in NWRP. APMC has exercised judgement in determining that it has joint control over NWRP and that the joint arrangement is a joint venture. This determination was based upon the assessment that APMC and CNRL, under the terms of the existing Processing Agreements, are currently not expected to purchase substantially all of the economic output of the Sturgeon Refinery (i.e. Refinery services) as compared to the estimated life of the Sturgeon Refinery.

APMC had entered into a term loan with NWRP which earned interest at a rate of prime plus six percent, compounded monthly, and was to be repaid over 10 years starting one year after COD. While the loan to NWRP was outstanding, APMC was entitled to a 25 percent voting interest on the Executive Leadership Committee ("ELC"), which is charged with

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

overseeing and making decisions on the operations of the Sturgeon Refinery. CNRL and North West Refining Inc. had 50 percent and 25 percent voting interests on the ELC, respectively.

The Commission had exercised judgment in determining that it had significant influence over NWRP. As the Commission had no equity ownership interest in NWRP, it did not apply equity accounting for NWRP in the prior period.

Pursuant to the Processing Agreements, NWRP processes bitumen and sells the refined products on behalf of the Tollpayers. As required by the terms of the Processing Agreements, a trust account (the "Initial Proceeds Trust Account" or "IPTA") has been established to facilitate the payments to and from the Tollpayers and NWRP. APMC has exercised judgment in determining that IPTA, on behalf of the Tollpayers, is a joint operation in which the Commission has a 75 percent interest in the assets, liabilities, revenue and expenses.

(d) NWRP - Monthly toll commitment

The Commission has used judgment to estimate its' toll commitments pursuant to the Processing Agreement included in note 25 Commitments. The toll has both a debt component and a monthly operating component. To estimate the future toll, management has used estimates for factors including future interest rates, operating costs, oil prices (WTI and light/ heavy differentials), refined product prices, gas prices and foreign exchange rates.

(e) Sturgeon Refinery Processing Agreement assessment

The Commission uses a cash flow model to determine if the unavoidable costs of meeting the obligations under the NWRP Processing Agreement exceed the economic benefits expected to be received. The model uses a number of variables to calculate the cash flows for APMC. Those variables include technical variables that arise from the design of the project such as pricing related variables including crude oil prices (WTI), heavy-light differentials, ultra-low sulphur diesel-WTI premiums, exchange rates, capital costs, operating costs, interest rates, and discount rates.

Technical inputs may be estimated with reasonable accuracy for a particular operating plan; however revenues and costs that depend upon market prices are challenging to estimate, particularly over long future time periods. The amended Processing Agreement has a term of 40 years and may be renewed for successive five year periods at APMC's option. In order to perform the onerous contract analysis, APMC management developed estimates for the key variables based primarily on Government of Alberta forecasts.

(f) Contingent consideration

In connection with the Optimization Transaction (note 6), NWRP entered into an agreement with NWU LP to utilize certain CO_2 capture technology in exchange for an annual licensing fee based on CO_2 captured from the Refinery, resulting in the recognition of a fair value provision for contingent consideration relating to APMC's acquisition of a partnership interest in NWRP.

The Commission uses a cash flow model to determine the fair value of the contingent consideration. The model uses a number of variables to calculate the cash outflows for APMC. Those variables include estimates and technical variables that arise from the design of the project such as the forecast of annual CO_2 volumes to be captured by the Refinery over its life until the estimated date of reclamation of December 31, 2100, an assumption that the annual licensing fee will meet the economic tests in future periods and the calculation of a credit adjusted risk free discount rate.

Technical inputs for annual C02 licensing fee may be adjusted in future periods based upon the operating performance of the Sturgeon Refinery.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

(g) *Interests in other entities*

APMC applies judgement in determining the classification of its interest in other entities, such as: (i) the determination of the level of control or significant influence held by the Commission; (ii) the legal structure and contractual terms of the arrangement; (iii) concluding whether the Commission has rights to assets and liabilities or to net assets of the arrangement; and (iv) when relevant, other facts and circumstances. The Commission has determined that the Investment in the KXL Expansion Project is a financial asset at fair value through profit or loss as described in IFRS 9 *Financial Instruments*.

(h) Fair value measurement of financial instruments

When the fair values of financial assets recorded in the Consolidated Statement of Financial Position cannot be measured based on quoted prices in active markets, their fair value is measured using valuation techniques.

The Commission has estimated the fair value of the KXL Investment at March 31, 2022 and 2021 using a probability-weighted valuation technique. The fair value of the KXL Investment is included in Level 3 of the fair value hierarchy (note 14) because it requires the use of significant unobservable assumptions in the valuation techniques used to determine the fair value estimate. The determination of the fair value of the KXL Investment is complex and relies on several critical judgements and estimates. These critical assumptions and estimates used in determining the fair value of the KXL Investment are: the identification of potential scenarios that would impact the amount and timing of cash flows relating to the KXL Investment, the expected probability of those outcomes, and the estimated cash inflows and outflows relating to potential outcomes. Fair value estimates may not necessarily be indicative of the amounts that could be realized or settled, and changes in assumptions could affect the reported fair value of the financial instrument. Assumptions used in the determination of the fair value of the KXL Investment will continue to be refined as outcomes become known and more information becomes available.

(i) Right-of-use assets

Purchase, extension and termination options are included in certain lease agreements to provide operational flexibility. To measure the lease liability, judgment is used to assess the likelihood of exercising these options. These assessments are reviewed when significant events or circumstances indicate that the likelihood of exercising these options may have changed. Estimates are also used to determine its incremental borrowing rate if the interest rate implicit in the contract is not readily determinable.

(j) Operating segments

The Commission has reviewed and determined its operating segments as disclosed in note 30.

5. NEW IFRS STANDARDS

(a) Accounting Standards Issued But Not Yet Adopted

Onerous Contracts – Costs of Fulfilling a Contract – Amendments to IAS 37

In May 2020, the IASB issued amendments to IAS 37 to specify which costs an entity needs to include when assessing whether a contract is onerous or loss-making.

The amendments apply a “directly related cost approach”. The costs that relate directly to a contract to provide goods or services include both incremental costs and an allocation of costs directly related to contract activities. General and administrative costs do not relate directly to a contract and are excluded unless they are explicitly chargeable to the counterparty under the contract.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

The amendments are effective for annual reporting periods beginning on or after January 1, 2022. The Commission will apply these amendments to contracts for which it has not yet fulfilled all its obligations at the beginning of the annual reporting period in which it first applies the amendments. The Commission does not currently anticipate any significant impact from these amendments on the consolidated financial statements as a result of the initial application.

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

In January 2020, the IASB issued amendments to paragraphs 69 to 76 of IAS 1 to specify the requirements for classifying liabilities as current or non-current, depending on the existence of the substantive right at the end of the reporting period for an entity to defer settlement of the liability for at least twelve months after the reporting period.

The amendments are effective for annual reporting periods beginning on or after January 1, 2023 and with early adoption permitted. These amendments must be applied retrospectively. The Commission is currently assessing the impact the amendments will have on current practice.

Amendments to IAS 8: Definition of Accounting Estimates

In February 2021, the IASB published amendments to IAS 8 to help entities distinguish between accounting policies and accounting estimates. Under the new definition, accounting estimates are monetary amounts in financial statements that are subject to measurement uncertainty.

The definition of a change in accounting estimates was deleted. However, the IASB retained the concept of changes in accounting estimates in the standard with the following clarifications:

- A change in accounting estimate that results from new information or new developments is not the correction of an error
- The effects of a change in an input or a measurement technique used to develop an accounting estimate are changes in accounting estimates if they do not result from the correction of prior period errors

The amendments are effective for annual reporting periods beginning on or after January 1, 2023 and changes in accounting policies and changes in accounting estimates that occur on or after the start of that period. Early adoption is permitted. The Commission is currently assessing the impact the amendments will have on current practice.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

6. INVESTMENT IN NORTH WEST REDWATER PARTNERSHIP

On June 30, 2021, the APMC negotiated a series of agreements (collectively, the "Agreements") through which APMC would purchase a limited partnership interest in NWRP), (the "Optimization Transaction"). Pursuant to the Agreements, APMC purchased the limited partnership interest from NWU LP, a company owned by North West Refining Inc. (Alberta). To effect this purchase, APMC acquired two newly formed subsidiaries of NWU LP (as later renamed to APMC (Redwater) L.P., and its general partner APMC (Redwater) Corp.) holding the interest in NWRP. Following the purchase of the limited partnership interest, APMC holds a 50 percent interest in NWRP. The other 50 percent interest holder in NWRP is CNR Redwater. The acquisition enables APMC to provide oversight and governance of the Refinery operations, maintenance, technical engineering, economic planning and scheduling, and optimization. To facilitate this oversight function, the APMC participates in the following committees: executive leadership, finance and insurance, commercial marketing, and audit. The CFO of APMC is the current chair of the audit committee.

As per the Partnership Interest Purchase Agreement, the contractual purchase price for the transaction was one Canadian dollar payable upon closing.

Also, in connection with the Optimization Transaction, NWRP entered into an agreement with NWU LP to utilize certain CO2 capture technology in exchange for an annual licensing fee based on CO2 captured from the Refinery. The licensing fee is payable at a rate of approximately $7.00/tonne of CO2 captured and transported in the Alberta Carbon Trunk Line ("ACTL"), with the first payment occurring in March 2022 for CO2 captured during the calendar years of 2020 and 2021. The licensing fee structure includes annual contractual escalation adjustments. Subsequent to the first payment, the annual licensing fee payable in future periods will be subject to reductions based on certain economic tests. APMC has recognized the fair value of its share of amounts expected to be payable in future periods for the licensing fee as contingent consideration of $217.3 million. The fair value estimate of the contingent consideration was calculated based upon the following: 1) management's forecast of annual CO2 volumes to be captured by the Refinery over its life until the estimated date of reclamation of December 31, 2100; 2) an assumption that the annual licensing fee payable will meet the economic tests in future periods; and 3) the calculation of a net present value of the expected license fee payments as discounted using a credit adjusted risk free rate of 3.35 percent. Management has performed a sensitivity analysis on the forecast annual CO2 volumes captured and the credit adjusted risk free discount rate estimates. If the forecast annual CO2 volumes captured were decreased by 5 percent or the discount rate was increased by 50 basis points, the contingent consideration would decrease by $10.7 million and $31.8 million, respectively.

APMC assessed the acquisition of the partnership interest in NWRP to be a joint venture and has accounted for the arrangement using the equity method of accounting in accordance with IAS 28 "Investments in Associates and Joint Ventures" . The cost of the investment comprises the purchase price and any directly attributable expenditures to obtain it. Accordingly, APMC has capitalized $56.3 million of transaction costs for legal and advisory consulting services to the cost of the investment. In addition, for the year ended March 31, 2022, $1.2 million (2021 - $6.0 million) of advisory consulting services related to the optimization transactions, but determined not to be directly attributable to the purchase, has been recorded to consulting in general and administrative expenses.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

The table below summarizes the purchase equation and allocation of fair value of the investment in NWRP acquired on the closing date of June 30, 2021:

($000s)	**Consideration**
Cash consideration of one dollar	-
Contingent consideration – license fee	**217,251**
	217,251
Transaction costs attributable to acquiring partnership interest	**56,235**
	273,486

($000s)	**Cost of Investment**
Share of fair value of net identifiable assets and liabilities	**(372,026)**
Goodwill on investment in NWRP	**645,512**
Cost of investment in NWRP	**273,486**

The determination of the share of fair value of net identifiable assets and liabilities as made by management at the time of the preparation of these financial statements was based on information then available. External valuation specialists were engaged to assist in the valuation of the fair value of identifiable assets and liabilities of NWRP. APMC decides, after discussions with the external valuation specialists, which valuation techniques and inputs to use in the measurement of fair value.

Under the Optimization Transaction, the original term of the Processing Agreements was extended by 10 years from 2048 to 2058. NWRP retired higher cost subordinated debt, which carried interest rates of prime plus 6 percent, with lower cost senior secured bonds at an average rate of approximately 2.56 percent, reducing interest costs to NWRP and associated tolls to the Tollpayers. As such, on June 30, 2021, NWRP repaid APMC’s and CNRL’s subordinated debt advances, resulting in $553.8 million of principal and interest repaid on the term loan receivable to APMC (note 12). In addition, $840 million was distributed by NWRP to CNRL and NWU LP prior to the Optimization closing.

To facilitate the Optimization Transaction, NWRP issued $500 million of 1.20 percent series L senior secured bonds due December 2023, $500 million of 2.00 percent series M senior secured bonds due December 2026, $1,000 million of 2.80 percent series N senior secured bonds due June 2031, and $600 million of 3.75 percent series O bonds due June 2051. Additionally, NWRP's existing $3.5 billion syndicated credit facility was amended. The $2.0 billion revolving credit facility was extended by three years to June 2024, and the $1.5 billion non-revolving credit facility was reduced by $0.5 billion to $1.0 billion and extended by two years to June 2023.

As a result of the Optimization Transaction, the APMC is a 50 percent owner in NWRP, in addition to being a 75 percent Tollpayer in the Sturgeon Refinery.

The Commission remains unconditionally obligated to pay to NWRP its 75 percent pro rata share of the debt component of the monthly fee-for-service toll over the 40-year tolling period. The Commission's estimated commitments for the monthly toll comprised of debt and operating components include the operating and financial commitments of NWRP (note 25).

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

The table below summarizes the change in the investment in NWRP joint venture for the nine month period ended March 31, 2022:

($000s)	**March 31, 2022**
Balance, March 31, 2021	**—**
Initial investment at June 30, 2021	**273,486**
APMC's share of loss for the period from the investment in NWRP	**(22,885)**
Balance, March 31, 2022	**250,601**

The income from the North West Redwater Partnership consists of the following for the nine month period ended March 31, 2022:

($000s)	**2022**
APMC's share of loss for the period from the investment in NWRP	**(22,885)**
Adjustments to NWRP contingent consideration in the year (note 19)	**25,496**
Income from North West Redwater Partnership	**2,611**

Summarized financial information of the joint venture, based on its IFRS financial statements, and reconciliation with the carrying amount of the investment in the consolidated financial statements at March 31, 2022 are as follows:

($000s)	**March 31, 2022**
Current assets, including cash and cash equivalents of $25,696	**229,974**
Non-current assets	**11,396,291**
Short term borrowings	**(24,000)**
Other current liabilities	**(276,808)**
Long term debt [1]	**(11,252,894)**
Other non-current liabilities	**(862,385)**
Deficit - 100%	**(789,822)**
APMC's share - 50%	**(394,911)**
Goodwill	**645,512**
APMC’s carrying amount of the investment	**250,601**

1. As at March 31, 2022, long term debt of NWRP consisted of senior secured notes of $8.8 billion and $2.4 billion outstanding under the Credit Facility. As at March 31, 2022, the weighted average interest rate on all senior secured notes amounts outstanding was 3.32 percent.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

Summarized statement of income or loss of NWRP:

($000s)	**March 31, 2022** [1]
Revenue from Tollpayers	**757,631**
Loss for the period (continuing operations)	**(45,769)**
APMC's share of loss for the period	**(22,885)**

1. Represents the nine months from the date of acquiring the partnership interest until March 31, 2022.
2. Included in NWRP's revenue for March 31, 2022 is $568 million paid by the Commission for its 75 percent share of the refining toll.
3. Included in the net profit (loss) for March 31, 2022 is the impact of depreciation and amortization expense of $245 million and interest and other financing expense of $226 million.

7. CASH AND CASH EQUIVALENTS

Cash and cash equivalents as at March 31, 2022 was $26.7 million (March 31, 2021 - $195.2 million). Cash and cash equivalents consist of deposits in the Consolidated Cash Investment Trust Fund (the "Fund") which is managed by Alberta Investment Management Corporation to provide competitive interest income while maintaining appropriate security and liquidity of depositors' capital. The Fund is comprised of high quality short-term fixed income securities with a maximum term to maturity of one year. For the twelve months ended March 31, 2022, the Commission earned $0.2 million (March 31, 2021 - $0.4 million) with a rate of return of 0.26 percent per annum (March 31, 2021 – 0.29 percent per annum). Due to the nature of Fund investments, the carrying value approximates fair value.

8. RESTRICTED CASH

Restricted cash as at March 31, 2022 was $72.6 million (March 31, 2021 – $11.3 million) and relates to the Sturgeon Refinery. It is restricted and held on behalf of the Sturgeon Refinery Tollpayers, namely APMC and CNRL. The amount reported is the 75 percent portion attributable to APMC as a Tollpayer. The Commission does not have immediate access to the cash held in the trust account. The cash is to be used for funding the Sturgeon Refinery processing operations and for paying all tolls. Any cash distributions will be in accordance with the Processing Agreement.

9. ACCOUNTS RECEIVABLE

($000s)	Note	**March 31, 2022**	March 31, 2021
Accounts receivable		**656,993**	402,452
Credit loss provision	24	**(952)**	(474)
Balance, end of period		**656,041**	401,978

Accounts receivable is comprised of receivables from crude oil royalty marketing transaction activities on behalf of the Province and receivables from Sturgeon Refinery product sales.

As at March 31, 2022, there was $210.2 million (March 31, 2021 – $53.0 million) of accounts receivable for marketing transaction activities primarily for the March 2022 delivery month, which was cash settled on April 25, 2022. In addition, there was $446.8 million (March 31, 2021 – $349.5 million) of account receivable related to the Sturgeon Refinery which consisted primarily of the sale of refined products delivered in March 2022. The terms related to the sale of refined products are not greater than net 21 days.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

10. INVENTORY

($000s)	March 31, 2022	March 31, 2021
Current		
Balance, beginning of period	51,711	—
Additions	1,803,746	828,822
Cost of sales	(1,759,753)	(777,111)
Balance, end of period – current portion	95,704	51,711
Long term		
Balance, beginning of period	6,877	—
Additions	—	6,877
Balance, end of period – long-term portion	6,877	6,877

As at March 31, 2022 there was $95.7 million (March 31, 2021 - $51.7 million) of hydrocarbon inventory classified as current as the Commission expects to sell it within the next twelve months of the financial reporting period. Product inventory is comprised of synthetic crude oil, intermediate products, ultra-low sulphur diesel, unconverted oil, diluent and sulphur.

As at March 31, 2022 there was $6.9 million (March 31, 2021 - $6.9 million) of long term inventory consisting of line fill and tank bottoms. The Commission does not anticipate to sell these volumes within the next 12 months.

11. CORPORATE ASSETS

($000s)	Office equipment & Improvements	Right-of-Use assets	March 31, 2022
Cost:			
Balance, March 31, 2021	—	—	—
Additions	167	478	645
Balance, March 31, 2022	167	478	645
Accumulated depreciation and amortization:			
Balance, beginning of period	—	—	—
Depreciation and amortization	(17)	(29)	(46)
Balance, March 31, 2022	(17)	(29)	(46)
Net book value – March 31, 2021	—	—	—
Net book value – March 31, 2022	150	449	599

Office equipment and improvements

In 2022, the Commission moved its head office resulting in leasehold improvements in addition to the purchase of furniture and fixtures. The Commission is depreciating its leasehold improvements and furniture and fixtures over a period of five years.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

Right-of-Use assets and lease liabilities

The Commission's right of use assets relate to leased office space, a reserved parking stall and office equipment. The office space and reserved parking stall are sub-leased from the Alberta Energy Regulator, a related party (note 27).

($000s)	**March 31, 2022**
Lease liabilities	
Cost:	
Balance, March 31, 2021	**—**
Additions	**478**
Lease payments related to right of use assets	**(35)**
Lease payments recognized as finance expense	**3**
Balance, March 31, 2022	**446**
Less: current portion	**(52)**
Balance, March 31, 2022	**394**

12. TERM LOAN RECEIVABLE

($000s)	**March 31, 2022**	March 31, 2021
Balance, beginning of period	**539,894**	652,470
Interest accrued	**26,326**	55,275
Repayments	**(566,220)**	(167,851)
	—	539,894
Credit loss provision	**—**	(541)
Less: current portion	**—**	(39,776)
Balance, end of period – long-term portion	**—**	499,577

During the twelve months ended March 31, 2022, NWRP paid $314.7 million (fifteen months ended March 31, 2021 - $124.1 million) of principal and $251.5 million (March 31, 2021 - $43.8 million) of interest on the term loan receivable. $553.8 million in principal and interest was repaid on June 30, 2021 pursuant to the Optimization Transaction (note 6).

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

13. SOFTWARE DEVELOPMENT

($000s)	**March 31, 2022**	March 31, 2021
Cost:		
Balance, beginning of period	**10,644**	10,644
Transfer from intangible assets under development	**—**	—
Balance, end of period	**10,644**	10,644
Accumulated depreciation and amortization:		
Balance, beginning of period	**(1,863)**	(532)
Depreciation and amortization	**(1,064)**	(1,331)
Balance, end of period	**(2,927)**	(1,863)
Net book value, end of period	**7,717**	8,781

The Commission internally developed operations software to handle actualization and settlement of royalty and marketing transactions. In addition, APMC purchased accounting software for reporting and financial settlement of transactions. Both systems became operational in 2019. As of March 31, 2022, the Commission did not have any transfers from intangible assets under development (March 31, 2021 - $nil). The intangible assets are amortized on a straight-line basis over the estimated useful life of the software of 10 years. The Commission has completed its review of intangible assets and determined there is no impairment.

14. INVESTMENT IN KXL EXPANSION PROJECT

On March 31, 2020, an Investment Agreement between TransCanada Pipeline Ltd. ("TCPL") and the Commission was executed. The Commission, through its newly created subsidiaries, agreed to extend financial support of up to US $5.3 billion (CAD $7.5 billion on the date the agreement was signed), beginning with an equity commitment of up to US $1.06 billion in 2020 for the KXL Expansion Project. Under the agreement, equity contributions were only to be provided up to December 31, 2020 and the contributions totaled CAD $1.035 billion. The balance of the support was in the form of a debt guarantee by the Commission to backstop the financing by TCPL affiliated entities for the KXL Expansion Project.

In 2020, the APMC subsidiaries used the capital contributions received from the Commission to invest in partnership interests of entities affiliated with TCPL. In return for the capital contributions in the partnership, Class A Interests were issued to the contributing subsidiaries according to their contributions. Class A Interests ranked above TCPL's equity investment in the entities and had certain voting rights. Capital contributions contributed up to March 31, 2026 were to earn a return in accordance with contractual terms. This return was accrued on a quarterly basis and adjusted to the carrying value of the Class A Interests. The Class A Interests issued were subject to call rights which enabled TCPL affiliated entities to repurchase the Class A Interests at any time and put rights which enabled APMC to sell the Class A Interests subsequent to the in-service date of the Keystone XL pipeline if certain conditions were met.

On January 8, 2021, TCPL exercised the repurchase right to purchase substantially all of the U.S. Class A Interests held by 2254746 Alberta Sub Ltd. for $632 million (US $497 million) by drawing on the TCPL credit facility guaranteed by APMC.

On January 20, 2021, U.S. President Biden revoked the Presidential Permit for the cross-border portion of the Keystone XL Pipeline. As a result of this, TCPL suspended the advancement of the Keystone XL pipeline project. The Commission ceased accruing a return on the remaining Class A Interests.

On June 9, 2021, the APMC, as directed by the Alberta Government entered into the Final KXL Agreement ("the Final KXL Agreement") with TC Energy for an orderly exit from the KXL project and partnership. APMC provided total contributions of CAD$1.035 billion on behalf of the TCPL partnerships to fund debt guarantee cancellation payments to the lenders as part

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

of the original investment agreement. The debt guarantee cancellation payments were paid on June 16, 2021 and the APMC has no further obligations relating to the Investment Agreement and/or the debt guarantee. In exchange for APMC making the guarantee cancellation payments through its wholly owned Canadian and US subsidiaries, Class C Interests were received from the TCPL partnerships. The Class C Interests received on June 16, 2021 do not have any put rights, voting rights or approval rights with respect to the business and affairs of the TCPL partnerships or carriers. Class A Interests were redeemed for a nominal amount on June 16, 2021. The Final KXL Agreement also provides a mechanism for future distribution of proceeds from liquidated assets of the KXL project to APMC, for its Class C interests, and to TCPL. Upon the completion of the liquidation of the KXL assets and the distribution of the gross proceeds thereof, the Final KXL Agreement also provides that all Canadian and US Class C Interests held by APMC subsidiaries shall redeemed for nominal consideration. APMC has reflected the terms of the Final KXL Agreement in determining its fair value estimates for the Investment in the KXL Expansion Project and the KXL Expansion Project Debt Guarantee in the consolidated financial statements as at March 31, 2022 and March 31, 2021. For the year ended March 31, 2022, the Commission has incurred a gain of $10.5 million (March 31, 2021: $255.8 million loss) on the estimated fair value of its Investment in the KXL Expansion Project.

A reconciliation of the change in fair value measured at FVTPL related to the KXL Expansion Project investment is as follows:

($000s)	
Balance, beginning of period - January 1, 2020	—
Contributions Class A interest – Canadian	383,288
Contributions Class A interest – USA	652,836
	1,036,124
Foreign exchange loss	(42,512)
Net change in fair value	(255,831)
TCPL repurchase of Class A interest – USA	(631,781)
Balance, end of period - March 31, 2021	106,000
Liquidation proceeds on Class C interests	**(37,795)**
Foreign exchange gain	**3,324**
Net change in fair value	**10,471**
Balance, end of period – March 31, 2022	**82,000**

The fair value of the KXL Investment as at March 31, 2022 and 2021 was estimated using a market approach to value Keystone XL Phase 4 pipeline assets under an abandonment scenario incorporating inputs for the estimated realizable value of the assets.

The determination of the fair value estimate included significant unobservable inputs (fair value measurement hierarchy – level 3): estimated cash inflows and outflows relating to an abandonment scenario. If the estimated cash flows relating to the abandonment scenario increase (decrease), the fair value estimate increases (decreases).

As the liquidation process under the abandonment scenario continues, more information is likely to become available that will impact the significant unobservable inputs. As a result, the estimated fair value will be impacted by events after the reporting period.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

15. ACCOUNTS PAYABLE

($000s)	**March 31, 2022**	March 31, 2021
Trade payables	**118,179**	105,806
Accrued liabilities	**430,131**	365,815
US income tax payable	**—**	4,331
Balance, end of period	**548,310**	475,952

Accounts payable and accrued liabilities are comprised of payables from marketing transactions and from Sturgeon Refinery activities.

As at March 31, 2022, there was $28.9 million (March 31, 2021 – $8.9 million) of payables for marketing activities primarily for the March 2022 delivery month, which were cash settled on April 25, 2022, as well as for general and administrative expenses.

In addition, there was $519.4 million (March 31, 2021 – $462.7 million) of account payable and accrued liabilities related to Sturgeon Refinery activities consisting of purchase of Refinery feedstock, and processor tolls for the March 2022 delivery month. The purchases of Refinery feedstock are settled on April 25, 2022. The processor tolls and optimization transactions are net settled against refined product sales proceeds on April 25, 2022.

16. DUE TO THE DEPARTMENT OF ENERGY

($000s)	**March 31, 2022**	March 31, 2021
Balance, beginning of period	**58,642**	84,586
Amount to be transferred	**1,363,271**	423,825
Amount remitted	**(1,202,964)**	(449,769)
Balance, end of period	**218,949**	58,642

17. SHORT TERM DEBT

		TB&F borrowings		
($000s)	Note	**Sturgeon Refinery**	**KXL Expansion Project**	**Total**
Balance, January 1, 2020		855,043	—	855,043
Draws		671,119	1,032,117	1,703,236
Repayments	6	(217,590)	(444,050)	(661,640)
Balance, March 31, 2021		1,308,572	588,067	1,896,639
Draws		**1,416,990**	**1,070,166**	**2,487,156**
Exchanged short term debt for long term debt bond		**—**	**(435,353)**	**(435,353)**
Repayments		**(1,671,030)**	**(245,985)**	**(1,917,015)**
Balance, March 31, 2022		**1,054,532**	**976,895**	**2,031,427**

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

Treasury Board & Finance ("TB&F") short term borrowings

The Commission entered into a Lending and Borrowing Agreement ("Agreement") with the GOA effective April 1, 2014. The Agreement provides the framework under which APMC may from time to time request the GOA to lend money to the APMC. The GOA and APMC must obtain an Order in Council (approved by the Lieutenant Governor in Council) to authorize the lending and borrowing dollar limits. TB&F is the government unit responsible for lending on behalf of the GOA.

The Commission has an Order in Council in place that allows it to borrow up to $1.8 billion for funding related to the Sturgeon Refinery. As at March 31, 2022, the Commission has $1.1 billion (March 31, 2021 - $1.3 billion) outstanding at various interest rates ranging from 0.29 percent to 0.93 percent. The tranches of borrowing are repayable over various terms not exceeding one year. During the year ended March 31, 2022, the Commission borrowed $1.4 billion related to the Sturgeon Refinery, primarily for new borrowings, with the remainder of the additions due to the rollover of short term notes. The Commission draws on its Sturgeon Order in Council monthly, to temporarily fund the Crown's purchase of feedstock. Cash received from the Sturgeon Refinery at the end of the month is used to repay borrowings. As of March 31, 2022, the undrawn amount on the Order in Council was $745.5 million.

The Commission has an Order in Council in place that allows it to borrow up to $2.0 billion for the Investment of the KXL Expansion Project. As at March 31, 2022, $976.9 million (March 31, 2021 - $588.1 million) was outstanding at various interest rates ranging from 0.19 percent to 0.85 percent. The tranches of borrowing are repayable over various terms not exceeding one year. In addition, at March 31, 2022, there was $427.5 million of long term bonds outstanding on the KXL Expansion Project (note 20). During the year ended March 31, 2022, the Commission incurred additional borrowings of $1.1 billion, which was primarily used to fund the KXL cancellation payments, with the remainder of the borrowings resulting from the rollover of short-term notes. As of March 31, 2022, the undrawn amount on the Order in Council was $615 million.

18. ACCRUED INTEREST PAYABLE

($000s)	**March 31, 2022**	March 31, 2021
Accrued interest on TB&F short term debt	**3,350**	3,001
Accrued interest on TB&F long term debt	**4,204**	—
Balance, end of period	**7,554**	3,001

19. CONTINGENT CONSIDERATION

($000s)	Note	**KXL Expansion Project**
Balance, March 31, 2021		—
Contingent consideration for acquisition of partnership interest	6	**217,251**
Accretion expense		**5,463**
Change in estimate - license fee expense recognized in the Partnership		**(2,069)**
- discount rate and timing		**(23,427)**
		197,218
Less: current portion		**(3,590)**
Balance, March 31, 2022		**193,628**

In connection with the Optimization Transaction (note 6), NWRP entered into an agreement with NWU LP to utilize certain CO2 capture technology in exchange for an annual licensing fee based on CO2 captured from the Refinery, resulting in the recognition of a $217.3 million provision for contingent consideration relating to APMC's acquisition of a partnership interest in NWRP.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

The fair value estimate of the contingent consideration was calculated based upon the following: 1) management's forecast of annual CO2 volumes to be captured by the Refinery over its life until the estimated date of reclamation of December 31, 2100; 2) an assumption that the annual licensing fee will meet the economic tests in future periods; and 3) the calculation of a net present value of the license fee payments are discounted using a credit adjusted risk free rate of 3.35 percent upon initial recognition provision and a credit adjusted risk free rate of 3.75 percent as at March 31, 2022.

20. LONG TERM DEBT

($000s)	**KXL Expansion Project**
Balance, March 31, 2021	—
Exchanged short term debt for long term debt bond	**435,353**
Amortization of premium on long term debt	**(7,860)**
Balance, March 31, 2022	**427,493**

TB&F borrowings on the KXL Expansion Project

In July 2021, the Commission exchanged $435.4 million of short term debt related to the KXL Expansion Project with TB&F for a 3 year bond with a coupon rate of 3.1 percent maturing on June 1, 2024. The bond was issued at a premium with $408.0 million due on maturity resulting in an effective annual interest rate of 0.87 percent.

Finance and accretion expenses for the year ended March 31, 2022 were reduced by the non-cash amortization of premium on long term debt of $7.9 million.

21. KXL EXPANSION PROJECT DEBT GUARANTEE

On June 9, 2021, APMC entered into the Final KXL Agreement with TC Energy. APMC provided total contributions of $1.035 billion on behalf of the TCPL partnerships to fund debt guarantee cancellation payments to the lenders as part of the original investment agreement. The debt guarantee cancellation payments were paid on June 16, 2021 and APMC has no further obligations relating to the Investment Agreement and/or the debt guarantee. Pursuant to the Final KXL Agreement, Class C Interests were issued in exchange for the payment of the debt guarantee cancellation payments.

($000s)	**March 31, 2022**	March 31, 2021
Balance, beginning of period	**1,035,002**	—
Expected credit loss allowance	**—**	1,035,002
Debt guarantee payment	**(1,035,002)**	—
Balance, end of period	**—**	1,035,002

22. OTHER REVENUE

During the year ended March 31, 2022, the APMC recognized $71.3 million of other revenue related to a compensatory settlement received by NWRP.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

23. STURGEON REFINERY PROCESSING AGREEMENT PROVISION

As at March 31, 2022, APMC assessed the Sturgeon Refinery Processing Agreement to determine if it represents an onerous contract. APMC uses a cash flow model to assess if the unavoidable costs related to the Processing Agreement with NWRP exceed the economic benefits to be received. The contract was determined to be onerous and APMC has recognized a provision which is calculated as the net present value of revenues from the sales of refined products less feedstock costs and the Refinery tolls charged by NWRP under the Processing Agreement, as well as the net present value of expected net benefit to be realized by APMC pursuant to the Processing Agreement as a result of its newly acquired 50 percent partnership interest in NWRP.

As a result of the Optimization Transaction, certain components of the Refinery tolls have been eliminated. In addition, the interest rate on NWRP's term debt was renegotiated, reducing the debt components of the Refinery toll. Commodity price forecasts have improved relative to March 31, 2021, increasing the net economic benefits expected to be received. The expected net economic benefits have also increased as result of the cash flows which APMC will realize from the Processing Agreement as a 50 percent joint venture owner in NWRP.

The undiscounted future cash net inflows are estimated to be $20.0 billion over the expected life of the project. The provision has been recognized by discounting these cash flows using a discount rate of 8.5 percent. The onerous contract provision is expected to be settled in periods up to May 2083.

During the periods ended March 31, 2022 and 2021, the movement in the Sturgeon Refinery Processing Agreement provision is as follows. The accretion expense is included in finance expense in the Consolidated Statement of Income (Loss) and Comprehensive Income (Loss).

($000s)	**March 31, 2022**	March 31, 2021
Balance, beginning of period	**2,494,000**	1,727,000
Change in loss provision	**(2,218,355)**	603,410
Accretion expense	**74,355**	163,590
	350,000	2,494,000
Less: current portion	**(299,000)**	(550,000)
Balance, end of period	**51,000**	1,944,000

APMC uses the GOA budgeted commodity price forecast for WTI, WCS, condensate and foreign exchange to estimate future cash flows. The most significant pricing variables that would impact the future cash flows of the contract are the forecasted WTI-WCS differential and foreign exchange rates. Due to the long-term nature of the contract, management has performed a sensitivity analysis on the forecasted WTI-WCS differential and the USD/CAD foreign exchange rates by decreasing them by 5 percent. The onerous contract provision would decrease by $266 million if, with all other variables held constant, the forecasted WTI-WCS differential and USD/CAD foreign exchange rates decreased by 5 percent.

24. FINANCIAL INSTRUMENTS

The Commission's financial instruments consist of cash and cash equivalents, restricted cash, accounts receivable, Investment in KXL Expansion Project, term loan receivable, accounts payable and accrued liabilities, due to Department of Energy, short term debt, accrued interest on short term debt, long term debt, license fee payable and lease obligations. Except for the Investment in KXL Expansion Project, the carrying values of these financial instruments approximate the fair value due to the short term nature of these instruments. Refer to note 3 – significant accounting policies for further information related to the Commission's accounting policies related to *IFRS 9 – Financial Instruments.*

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

The Commission is exposed to a variety of financial risks: market risk (interest rate risk), credit risk, liquidity risk and commodity price risk. The nature of the risks faced by the Commission and its policies for managing such risks are detailed below.

(a) Interest rate risk

Interest rate risk is the risk that the future cash flows of a financial instrument will fluctuate because of changes in market interest rates. The Commission is exposed to interest rate risk from fluctuations in rates on its cash and cash equivalents balance and the interested charged on the short term debt and long term debt.

(b) Credit risk

Credit risk is the risk of financial loss to the Commission if a customer or party to a financial instrument fails to meet its contractual obligation and arises principally from the Commission's cash and cash equivalents, cash held in trust, accounts receivable and term loan and other financial instruments. The maximum amount of credit risk exposure of these instruments is limited to the carrying value of the balances disclosed in these Annual Financial Statements.

The Commission manages its exposure to credit risk on cash and cash equivalents by placing these financial instruments with the Consolidated Cash Investment Trust Fund (note 7).

A substantial portion of the Commission's accounts receivable are with its customers in the oil and gas industry and are subject to normal industry credit risk. The Commission monitors the credit risk and credit rating of all customers on a regular basis. Aged receivable balances are monitored and a credit loss provision is provided in the period in accordance with IFRS 9. Any credit losses on accounts receivable would be charged on to the DOE.

Credit loss provision

($000s)	**March 31, 2022**	March 31, 2021
Accounts receivable – trade		
Balance, beginning of period	**248**	220
Change to loss provision	**204**	28
Balance, end of period	**452**	248
Accounts receivable – Sturgeon Refinery		
Balance, beginning of period	**226**	—
Change to loss provision	**274**	226
Balance, end of period	**500**	226
Term loan receivable and accrued interest		
Balance, beginning of period	**541**	261
Change to loss provision	**(541)**	280
Balance, end of period	**—**	541
Total change to loss provision for the period	**(63)**	534

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

The loss provision for trade accounts receivable is recorded to General and Administrative Expenses (note 28) in the Consolidated Statement of Income (Loss) and Comprehensive Income (Loss). The loss provisions for Sturgeon Refinery accounts receivable and term loan receivable have been recorded to Provisions for Sturgeon Refinery in the Consolidated Statement of Income (Loss) and Comprehensive Income (Loss).

(c) Liquidity risk

Liquidity risk is the risk that the Commission will not be able to meet its financial obligations as they come due. The Commission actively manages its liquidity through cash, accounts receivables and debt management strategies. The APMC has the ability to obtain financing through external banking credit facilities or from TB&F.

As at March 31, 2022, excluding short term debt, the Commission's non-derivative financial liabilities have contractual maturities (including interest payments where applicable) are summarized below.

($000s)	**Total**	**< 1 Year**	**1-3 Years**	**3-5 Years**	**More than 5 Years**
Accounts payable	548,310	548,310	—	—	—
Due to the Department of Energy	218,949	218,949	—	—	—
Long term debt - KXL Expansion Project three year bonds[1]	408,000	—	408,000	—	—
Interest on KXL Expansion Project three year bonds	31,620	12,648	12,648	6,324	—
Sturgeon Refinery Processing Agreement provision [2]	350,000	299,000	288,000	98,000	(335,000)
Lease liabilities	446	52	101	101	192
Contingent consideration	197,218	3,590	7,800	7,825	178,003
	1,754,543	**1,082,549**	**716,549**	**112,250**	**(156,805)**

1. Represents the face value due at maturity.
2. The amount more than 5 years represents the present value of estimated net cash inflows from the Sturgeon Refinery in later years.

(d) Commodity price risk

Commodity price risk is the risk that future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted not only by the relationship between the Canadian and United States dollars but also worldwide economic events that influence supply and demand.

The Commission’s operational results and financial condition are impacted by prices realized on sales of refined products, feedstock purchases and tolls at the Sturgeon Refinery. In addition, the Commission’s financial position and results are also impacted by changes in estimates of future commodity prices used in the determination of the net cash flows of the Processing Agreement. As at March 31, 2022, the Commission does not have any commodity price risk management contracts. Movement in commodity prices could have a significant positive or negative impact on the Commission’s net income (loss).

(e) Foreign exchange risk

Foreign exchange risk is the risk that the fair value or future cash flows of an exposure will fluctuate because of changes in foreign exchange rates. The Commission’s exposure to the risk of changes in foreign exchange rates primarily relate to the Commission’s KXL Investment. A portion of the KXL Investment is denominated in a foreign currency and this exposes the Commission to the risk that the fair value will fluctuate due to changes in the exchange rate.

The Commission mitigates foreign exchange risk by minimizing its US currency held.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

(f) *Offsetting financial assets and liabilities*

The Commission enters into contracts with single shipper pipelines, where APMC sells oil to the carrier at the inlet and purchases the oil back at the terminus of the pipeline. The agreements are written to allow for offsetting of accounts receivable and accounts payable, which are presented on a net basis on the Consolidated Statement of Financial Position.

The following table presents the recognized financial instruments that are offset as a result of netting arrangements and the intention to settle on a net basis with counterparties.

($000s)	**Note**	**Gross amounts of recognized financial assets (liabilities)**	**Gross amounts of recognized financial assets (liabilities) offset in the statement of financial position**	**Net amounts of financial assets (liabilities) recognized in the statement of financial position**
Accounts receivable		403,716	1,738	401,978
Accounts payable		(477,839)	(1,887)	(475,952)
Net position, March 31, 2021		(74,123)	(149)	(73,974)
Accounts receivable	9	**656,229**	**188**	**656,041**
Accounts payable	15	**(552,070)**	**(3,760)**	**(548,310)**
Net position, March 31, 2022		**104,159**	**(3,572)**	**107,731**

Capital Management and Liquidity

The Commission's objective when managing capital is to maintain a flexible capital structure and sufficient liquidity to meet its financial obligations and to execute its business plans. The Commission considers its capital structure to include equity (deficit), the short and long term debt available borrowings under outstanding debt agreements, and net working capital (deficit). The Commission’s objectives when managing capital are to safeguard the Commission’s ability to continue as a going concern and provide returns to the DOE through responsible marketing of conventional crude oil royalty volumes and its other business activities. The Commission does not have any externally imposed restrictions on its capital. The Commission monitors its current and forecasted capital structure in response to changes in economic conditions and the risk characteristics of its business activities. Adjustments are made on an ongoing basis in order to meet its capital management objectives. In light of the continued uncertainty in the macroeconomic environment, the Commission continues to monitor interest rate volatility in determining whether the short term borrowings will remain short term with a maturity of less than one year or if longer maturity debt is more prudent given the current economic environment with increased inflationary pressures.

The APMC believes that its current financial obligations including current commitments and working capital deficit (as defined as current assets, less current liabilities) will be adequately funded by the available borrowing capacity on the Order of Councils. Combined with its value-creating mandate initiatives, the Commission anticipates to be in a position that it will be able to meet its commitment requirements in the next twelve months.

25. COMMITMENTS

The estimated NWRP tolls under the Processing Agreement are as follows for future years ended:

(In $ millions)	**3/31/2023**	**3/31/2024**	**3/31/2025**	**3/31/2026**	**3/31/2027**	**Beyond 2027**	**Total**
NWRP Tolls	**921**	**814**	**850**	**804**	**779**	**30,494**	**34,662**

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

Under the Processing Agreement, after COD, the Commission is obligated to pay a monthly toll comprised of debt and operating components. The processing agreement has a term of 40 years starting with the Toll Commencement Date (June 1, 2018). The Commission has very restricted rights to terminate the Processing Agreement, and is unconditionally obligated to pay its 75 percent pro rata share of the debt component of the monthly fee-for-service toll over the 40-year tolling period. The tolls under the Processing Agreement assuming: market interest rates; and 2 percent operating cost inflation rate, are estimated above. The toll commitments above are undiscounted and are estimated up to the end of the Processing Agreement term (May 31, 2058). The increase in expected tolls compared to 2021 is primarily related to the addition of 10 years to the agreement term pursuant to the Optimization Transaction. These undiscounted tolls do not take into account the net margin received on the sale of APMC's bitumen feedstock.

The estimated commitments for office lease and parking costs are as follows for future years ended:

(In $000s)	3/31/2023	3/31/2024	3/31/2025	3/31/2026	3/31/2027	Total
Office lease and parking [1]	**340**	**340**	**340**	**150**	**—**	**1,170**

1. Includes estimates for annual operating costs and property taxes.

The office lease has been capitalized as a right-of-use-asset as detailed in note 11 and the sub-leased office space is with a related party as detailed in note 27.

NWRP is a defendant in legal action arising in the normal course of business and construction close-out. The Commission believes that any liabilities that might arise pertaining to any such matter will not have a material effect on its consolidated financial position.

26. INCOME TAXES

As stated in Note 1 above, the Commission is exempted from Canadian federal and provincial corporate income taxes. However, 2254746 Alberta Sub Ltd., a Delaware incorporated company and 2254746 Alberta Ltd., an Alberta incorporated company have exposure to US federal and state corporate income taxes.

During the year ended March 31, 2022, the Commission recorded $nil (2021 - $5.2 million) of income tax expense due to the Internal Revenue Service ("IRS") in the United States. During the 2021 period, accretion income of $21.5 million (US$16.4 million) (note 14) was earned on the U.S. Class A Interests held by 2254746 Alberta Sub Ltd. (the "US subsidiary").

US corporate taxes were due on the accretion income earned by the US subsidiary and the remainder was distributed by an intercorporate dividend to the Canadian holding company, 2254746 Alberta Ltd., which also resulted in withholding taxes being paid to the IRS. The total of the US corporate taxes and withholding taxes paid to the IRS of $5.2 million has all been expensed as it is uncertain that any of the taxes will be recoverable.

The Commission does not currently have any deferred income tax assets or liabilities.

27. RELATED PARTY TRANSACTIONS

The DOE pays the Commission a fee to market crude oil on its behalf under conventional crude oil marketing activities, reported as marketing fees within the Consolidated Statement of Income (Loss) and Comprehensive Income (Loss). The amounts owing to the DOE have been disclosed in note 16.

The Commission enters into transactions with the DOE, a related party, in the normal course of business. For the year ended March 31, 2022, the DOE incurs costs for salaries on behalf of the Commission, as recognized under wages and benefits of $2.0 million (March 31, 2021 - $2.7 million) within the Consolidated Statement of Income (Loss) and Comprehensive Income (Loss). In addition, no DOE salaries were capitalized within intangible assets (March 31, 2021 - $nil).

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission
For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021
(Expressed in thousands of Canadian dollars, unless stated otherwise)

Service Alberta, a related party provided the software and maintenance services totaling $0.3 million for the year ended March 31, 2022 (March 31, 2021 - $0.6 million). These expenditures were recognized within the Consolidated Statement of Income (Loss) and Comprehensive Income (Loss). In addition, no technology services related to software development have been capitalized within intangible assets (March 31, 2021 - $nil).

In August 2021, the Commission entered into a sublease agreement for office premises with the Alberta Energy Regulator (the "AER"), a related party. For the year ended March 31, 2022, the APMC paid $0.3 million (March 31, 2021 - $nil) to the AER for office rent and parking expenses, shared services, and leasehold improvements (note 11). See note 11 for details of the office lease which has been capitalized as a right-to-use asset.

The Commission has outstanding short term debt with TB&F. For more details see note 17.

Information on the Term Loan Receivable from NWRP and summarized financial information for NWRP is found in note 12. Refer to note 4(c) for a description of the Sturgeon Refinery, note 4(d) for the NWRP monthly toll commitment and note 23 for the Sturgeon Refinery Processing Agreement Provision.

Information on the Commission's investment in the KXL Expansion Project Class A partnership interests is found in note 14 and the KXL Expansion Project Debt Guarantee is found in note 21.

The Board members of the Commission, executive management and their close family members are deemed related parties of the Commission. Transactions with close family members are immaterial; compensation for Board members and executive management is disclosed in note 29.

28. GENERAL AND ADMINISTRATIVE EXPENSES

($000s)	**Twelve Months ended March 31, 2022**	Fifteen Months ended March 31, 2021
Wages and benefits	**5,884**	5,350
Software and maintenance	**861**	1,268
Consulting	**5,454**	11,770
Dues and subscriptions	**263**	288
Director fees	**119**	171
Office rent and property taxes	**158**	—
Change in loss provision for accounts receivable	**204**	28
Other	**119**	65
Total general and administrative expenses	**13,062**	18,940

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

29. SALARIES AND BENEFITS

Key management personnel include the Commission's Board Members, Chief Executive Officer, Chief Financial Officer, Director, Operations and Director, Business Development. The amounts in the Annual Financial Statements relating to board members and key management compensation for the twelve months ended March 31, 2022 and the fifteen months ended March 31, 2021 are as follows:

	Base Salary		**Other Cash Benefits**[2]		**Other Non-cash Benefits**[3]		**Total**	
($000s)	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021
Board Members[1]	**—**	—	**119**	171	**—**	—	**119**	171
Chief Executive Officer	**301**	381	**94**	112	**6**	8	**401**	501
Chief Financial Officer[4]	**281**	15	**70**	3	**6**	—	**357**	18
Director, Operations	**267**	338	**52**	91	**5**	5	**324**	434
Director, Business Development[5]	**220**	138	**42**	27	**4**	—	**266**	165
Director, Finance[6]	**117**	296	**208**	32	**2**	4	**327**	332
	1,186	1,168	**585**	436	**23**	17	**1,794**	1,621

1. The Chair of the Board (Deputy Minister, DOE) and one director (Assistant Deputy Minister, DOE) are unpaid. There are five outside Board Members. The outside Board Members receive an annual retainer and meeting fees.
2. As per their employment contracts, the key management personnel receive cash payments in lieu of benefits. No bonuses were paid during the year.
3. Included in Other Non-cash benefits is parking.
4. The Chief Financial Officer was hired effective March 15, 2021.
5. The Director of Business Development was hired effective August 18, 2020.
6. The Director, Finance effective end date was September 29, 2021. Other Cash Benefits also includes severance and unpaid earned vacation.

30. SEGMENT INFORMATION

The Commission's reportable segments were determined based on differences in products and support services offered under its mandate as disclosed in note 1. The Commission has four reportable segments: conventional crude marketing operations, the Sturgeon Refinery, the Investment in NWRP and the KXL Expansion Project. The Sturgeon Refinery segment accounts for the APMC's 75 percent interest as a Tollpayer in the Sturgeon Refinery, or IPTA. After the Optimization Transaction on June 30, 2021, the investment in NWRP is recognized as a joint venture and is accounted for using equity method accounting (note 3).

These reportable segments of the Commission have been derived because they are the segments: (a) that engage in business activities from which revenues are earned and expenses are incurred; (b) whose operating results are regularly reviewed by the Commission's chief operating decision maker, identified as the Commission's Chief Executive Officer, to make decisions about resources to be allocated to each segment and assess its performance; and (c) for which discrete financial information is available. The Commission regularly provides financial information on revenues and expenses of each segment, but not total assets or liabilities by segment.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

Twelve months ended March 31, 2022 and the fifteen months ended March 31, 2021

	Conventional Crude Oil Marketing		Sturgeon Refinery (Tollpayer)		NWRP Joint Venture (Refinery Owner)		KXL Expansion Project		Total	
($000s)	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021
				Note 2(f)						Note 2(f)
REVENUES										
Refinery sales	**—**	—	**2,381,861**	999,251	**—**	—	**—**	—	**2,381,861**	999,251
Other revenue	**—**	—	**71,250**	—	**—**	—	**—**	—	**71,250**	—
Marketing fee income	**11,201**	5,256	**—**	—	**—**	—	**—**	—	**11,201**	5,256
	11,201	5,256	**2,453,111**	999,251	**—**	—	**—**	—	**2,464,312**	1,004,507
Finance income	**77**	291	**26,461**	55,412	**—**	—	**—**	—	**26,538**	55,703
	11,278	5,547	**2,479,572**	1,054,663	**—**	—	**—**	—	**2,490,850**	1,060,210
EXPENSES										
Refinery feedstock purchases	**—**	—	**1,759,753**	777,111	**—**	—	**—**	—	**1,759,753**	777,111
Refinery tolls	**—**	—	**804,055**	837,150	**—**	—	**—**	—	**804,055**	837,150
General and administrative	**10,079**	7,682	**1,529**	6,151	**—**	—	**1,454**	5,107	**13,062**	18,940
Depreciation and amortization	**1,110**	1,331	**—**	—	**—**	—	**—**	—	**1,110**	1,331
Loss (gain) on foreign exchange	**(67)**	88	**(362)**	1,988	**—**	—	**(3,145)**	34,749	**(3,574)**	36,825
Finance costs	**3**	—	**78,010**	178,144	**5,463**	—	**5,187**	1,839	**88,663**	179,983
Income from North West Redwater Partnership	**—**	—	**—**	—	**(2,611)**	—	**—**	—	**(2,611)**	—
Sturgeon Refinery Processing Agreement provision	**—**	—	**(2,218,622)**	603,916	**—**	—	**—**	—	**(2,218,622)**	603,916
KXL Expansion Project Debt Guarantee loss allowance	**—**	—	**—**	—	**—**	—	**—**	1,035,002	**—**	1,035,002
Fair value gain investment in KXL Expansion Project	**—**	—	**—**	—	**—**	—	**(10,471)**	255,831	**(10,471)**	255,831
Total expenses	**11,125**	9,101	**424,363**	2,404,460	**2,852**	—	**(6,975)**	1,332,528	**431,365**	3,746,089
Net income (loss) and Comprehensive income (loss) before taxes	**153**	(3,554)	**2,055,209**	(1,349,797)	**(2,852)**	—	**6,975**	(1,332,528)	**2,059,485**	(2,685,879)
Income taxes	**—**	—	**—**	—	**—**	—	**—**	5,199	**—**	5,199
Net income (loss) and Comprehensive income (loss) after taxes	**153**	(3,554)	**2,055,209**	(1,349,797)	**(2,852)**	—	**6,975**	(1,337,727)	**2,059,485**	(2,691,078)

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the Twelve Months ended March 31, 2022 and the Fifteen Months ended March, 31, 2021

(Expressed in thousands of Canadian dollars, unless stated otherwise)

31. SUPPLEMENTAL CASH FLOW

Details of changes in non-cash working capital from operating activities include the following:

($000s)	**Twelve Months ended March 31, 2022**	Fifteen Months ended March 31, 2021
Restricted cash	**(61,286)**	(11,282)
Accounts receivable	**(254,541)**	(318,236)
Inventory	**(43,993)**	(51,711)
Accounts payable and accrued liabilities	**72,358**	439,768
Due to the Department of Energy	**160,307**	(25,944)
Changes in non-cash working capital from operating activities	**(127,155)**	**32,595**

32. SUBSEQUENT EVENTS

Subsequent to March 31, 2022 and through to June 3, 2022, the APMC repaid $12.3 million, net of rollovers, from TB&F related to the Sturgeon Refinery, primarily due to excess cash flows. In addition, the Commission incurred additional borrowings of $1.0 million as a result of the rollover of KXL outstanding debt. The average term of the loans rolled over are for a period of 32 days and subject to an average interest rate of 1.01 percent.

Balancing Pool

Financial Statements

Years Ended December 31, 2021 and 2020

Table of Contents

Independent auditor's report

To the Board of Directors of Balancing Pool

Our opinion

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of Balancing Pool (the Corporation) as at December 31, 2021 and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards (IFRS).

What we have audited

The Corporation's financial statements comprise:

- the statement of financial position as at December 31, 2021;
- the statement of income (loss) and comprehensive income (loss) for the year then ended;
- the statement of cash flows for the year then ended; and
- the notes to the financial statements, which include significant accounting policies and other explanatory information.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence

We are independent of the Corporation in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

Other information

Management is responsible for the other information. The other information comprises the Management's Discussion and Analysis.

Our opinion on the financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

PricewaterhouseCoopers LLP
111-5th Avenue SW, Suite 3100, Calgary, Alberta, Canada T2P 5L3
T: +1 403 509 7500, F: +1 403 781 1825

"PwC" refers to PricewaterhouseCoopers LLP, an Ontario limited liability partnership.

pwc

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of management and those charged with governance for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Corporation’s ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Corporation or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Corporation’s financial reporting process.

Auditor’s responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor’s report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

pwc

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Corporation's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Corporation's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Corporation to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Alberta
April 13, 2022

Statements of Financial Position

Balancing Pool
(in thousands of Canadian dollars)

	2021	2020
Assets		
Current assets		
Cash and cash equivalents	**32,963**	223,737
Trade and other receivables (Note 5)	**18,556**	109,192
Right-of-use assets (Note 7)	**25**	89
	51,544	333,018
Right-of-use assets (Note 7)	**2**	-
Property, plant and equipment	**7**	15
Total Assets	**51,553**	333,033
Liabilities		
Current liabilities		
Trade payables and other accrued liabilities (Note 9)	**11,468**	399,712
Current portion of related party loan (Note 16)	**206,952**	202,932
Current portion of reclamation and abandonment provision (Note 10)	**169**	263
Current portion of lease liability (Note 11)	**25**	91
	218,614	602,998
Reclamation and abandonment provision (Note 10, Note 13)	**41,988**	38,188
Lease liability (Note 11)	**2**	-
Related party loan (Note 16)	**503,873**	503,546
Total Liabilities	**764,477**	1,144,732
Net liabilities attributable to the Balancing Pool deferral account (Note 1, 12)	**(712,924)**	(811,699)
Contingencies and commitments (Note 13)		
Subsequent events (Note 17)		

On behalf of the Balancing Pool:

Original signed by

Greg Clark
Chair

Original signed by

Greg Pollard
Vice-Chair

The accompanying notes are an integral part of these financial statements.

Statements of Income (Loss) and Comprehensive Income (Loss)

Balancing Pool

(in thousands of Canadian dollars)

	2021	2020
Revenue from contracts with customers		
Sale of electricity and ancillary service	**-**	641,046
Consumer collection (Note 4)	**135,798**	145,404
	135,798	786,450
Other income (loss) from operating activities		
Changes in fair value of Hydro Power Purchase Arrangement	**-**	(19,608)
Payments in lieu of tax	**(16,901)**	15,856
Interest income	**575**	1,250
	(16,326)	(2,502)
Expenses		
Cost of sales (Note 14)	**7,437**	776,795
Reclamation and abandonment provision (Note 10, Note 13)	**4,265**	6,993
Mandated costs (Note 16)	**3,827**	5,069
General and administrative	**3,095**	6,690
Commercial dispute costs (recovery) Note 15	**(10,236)**	2,320
	8,388	797,867
Income (loss) from operating activities	**111,084**	(13,919)
Other income (expense)		
Finance expense (Note 8)	**(13,983)**	(23,310)
Other income	**1,675**	155
	(12,308)	(23,155)
Change to the Balancing Pool deferral account (Note 12)	**98,776**	(37,074)

The accompanying notes are an integral part of these financial statements.

Statements of Cash Flows

Balancing Pool

(in thousands of Canadian dollars)

	2021	2020
Cash flow provided by (used in)		
Operating activities		
Change to the Balancing Pool deferral account	**98,776**	(37,074)
Adjustments for		
Amortization and depreciation (Note 7)	**107**	289,975
Reclamation and abandonment provision (Note 10)	**4,265**	6,993
Fair value changes on Hydro Power Purchase Arrangement	**-**	19,608
Finance expense (Note 8)	**13,983**	23,310
Emission credits retired	**-**	14,446
Reclamation and abandonment expenditures (Note 10)	**(617)**	(1,973)
Net change in other assets:		
Long-term receivable	**-**	1,980
Net change in non-cash working capital:		
Trade and other receivables	**90,636**	(23,541)
Trade payable and other accrued liabilities	**(388,243)**	187,187
Net cash (used in) provided by operating activities	**(181,093)**	480,911
Investing activities		
Purchase of property, plant and equipment	**-**	(9)
Purchase of emission credits	**-**	(11,947)
Net cash used in investing activities	**-**	(11,956)
Financing activities		
Hydro Power Purchase Arrangement net receipts	**-**	91,059
Lease payments (Note 11)	**(102)**	(417,483)
Payments on related party loan (Note 16)	**(698,710)**	(734,548)
Proceeds from issue of related party loan (Note 16)	**702,671**	735,419
Finance expense on related party loan	**(13,540)**	(15,702)
Net cash used in financing activities	**(9,681)**	(341,255)
Change in cash and cash equivalents	**(190,774)**	127,700
Cash and cash equivalents, beginning of year	**223,737**	96,037
Cash and cash equivalents, end of year	**32,963**	223,737

The accompanying notes are an integral part of these financial statements.

Notes to Financial Statements

Balancing Pool

1. Reporting Entity and Nature of Operations

Formation and Duties of the Balancing Pool

The Balancing Pool was formed to facilitate policy implementation and to support the functioning of the electricity industry for the benefit of Albertans. The *Electric Utilities Act (2003)* ("EUA") and certain regulations made under it established the mandate of the Balancing Pool, which was principally to manage certain assets, liabilities, revenues, and expenses associated with the ongoing evolution of Alberta's electric industry.

The Balancing Pool was originally established in 1998 as a separate financial account of the Power Pool Council (the "Council") and commenced operations in 1999. The Council was a statutory corporation established under the *Electric Utilities Act of Alberta (1995)*. With the proclamation of the EUA on June 1, 2003, the Balancing Pool was established as a separate statutory corporation (the "Corporation"). The assets and liabilities of the Council that related to the duties, responsibilities and powers of the Balancing Pool were transferred to the Corporation.

Under the EUA, the Corporation is required to operate without a profit or loss (Note 12). No share capital for the Corporation has been issued.

The Balancing Pool Board of Directors (the "Board") consists of individual members who are independent of persons having a material interest in the Alberta electric industry. The members of the Board are appointed by the Minister of Energy of the Government of Alberta ("Minister of Energy").

The Balancing Pool was required to respond to certain extraordinary events during the operating period of all of the Power Purchase Arrangements ("PPAs"), such as force majeure, PPA unit destruction, PPA Buyer or PPA Owner default, or the termination of a PPA. In the event of termination of a PPA by a PPA Buyer, the Balancing Pool assumed the rights and obligations of the PPA Buyer pursuant to that PPA at the time of termination (assuming the PPA continues). Under the EUA the Balancing Pool was required to manage generation assets in a commercial manner.

The head office and records of the Balancing Pool are located at Suite 520, 330 Fifth Avenue S.W., Calgary, Alberta, Canada.

Activities of the Balancing Pool

The initial allocation of assets and liabilities to the Balancing Pool was charged to a deferral account. Differences between annual revenues and expenditures are also charged or credited to the Balancing Pool deferral account.

The EUA requires that the Balancing Pool forecast its revenues and expenses. Any excess or shortfall of funds in the accounts is to be allocated to, or provided by, electricity consumers over time.

Expiry of the Power Purchase Arrangements

The thermal PPAs (Genesee, Keephills and Sheerness) and Hydro PPA expired on December 31, 2020. Offer control of these PPAs reverted back to the PPA Owners effective January 1, 2021.

Notes to Financial Statements

Balancing Pool

In 2021, the Balancing Pool's business activities included the collection of funds from electricity consumers, payments (refund) in lieu of tax, repayment of the outstanding loan with the Provincial government, resolving outstanding commercial and legal disputes related to the PPAs, collection of funds related to the Utility Bill Deferral Program, acting as agent for Small Scale Generators and funding the Utility Consumer Advocate and funding certain decommissioning obligations.

Revenue from Contracts with Customers

i) Sale of electricity, ancillary service and generating capacity

Prior to December 31, 2020, the Balancing Pool earned revenue from the sale of electricity and ancillary service sourced from the PPAs it held, namely, Genesee, Sheerness and Keephills.

Electricity that was not otherwise contracted was sold into the spot market. Ancillary services from the PPAs were sold to the Alberta Electric System Operator ("AESO") through a competitive exchange.

ii) Consumer collection

Pursuant to Section 82 of the EUA, the Balancing Pool collects or allocates an annualized amount from electricity customers. The consumer collection from the AESO is being accounted for as revenue of the Balancing Pool. The Balancing Pool has applied judgment in determining that the consumer collection collected via rate Rider F, as specified in the EUA, is analogous to a contract with a customer. The legislation contained in the EUA established the Balancing Pool's right to recover operating shortfalls from electricity customers via Rider F of the AESO tariff and can be interpreted as a contract with a customer.

Other Income

i) Hydro Power Purchase Arrangement ("Hydro PPA")

Pursuant to Section 85 of the EUA, the Balancing Pool held the Hydro PPA. As such, the Balancing Pool retained the right to the market value of the associated electricity and was responsible for the PPA obligations from certain hydro plants in the Province of Alberta. The cash flows associated with the Hydro PPA were based on the electricity market price multiplied by a notional amount of production, less PPA obligations as outlined in the PPA. The expected net present value of these estimated payments was recorded as an asset and any revaluation adjustment is included in net results of income (loss).

Under the change in law provisions of the Hydro PPA, the Balancing Pool is entitled to any benefit from emission performance credits. No amount has been recognized at this time.

ii) Investment income and changes in fair value of investments

Cash, cash equivalents and investments held by the Balancing Pool generate investment income consisting of interest.

iii) Payments (refunds) in Lieu of Tax ("PILOT")

Pursuant to Section 147 of the EUA, the Balancing Pool collects installments (refunds) a notional amount of tax from electricity companies controlled by municipal entities that are active in Alberta's competitive electricity market and are otherwise exempt from the payment of tax under the *Income Tax Act* or the *Alberta Corporate Tax Act*. The Balancing Pool does not calculate instalment payments or refunds and it does not audit PILOT filings. PILOT instalments are calculated by the payer and PILOT filings are subject to audit by Alberta Tax and Revenue.

Notes to Financial Statements

Balancing Pool

Expenses

i) Cost of sales

Under the terms of the various PPAs, the Balancing Pool was obligated to pay certain fixed and variable costs to the PPA Owners of the various generation assets. Included in Cost of Sales are costs associated with the administration of the Small Scale Generation Regulation.

ii) Other costs

Under the terms of government legislation, the Balancing Pool is obligated to make payments to certain entities for such matters as reclamation and abandonment and force majeure. The Minister of Energy may direct the Balancing Pool to fund specific payments under Section 148 of the EUA, which amounts are included in mandated costs.

2. Basis of Presentation

These financial statements for the year ended December 31, 2021 have been prepared by management in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and include as comparative information the year ended December 31, 2020.

These financial statements were authorized and approved for issue by the Board of the Balancing Pool on April 13, 2022.

3. Summary of Significant Accounting Policies

The significant accounting policies used in the preparation of these financial statements are as follows:

Basis of Measurement

These financial statements have been prepared on a historical cost convention.

Revenue from Contracts with Customers

The Balancing Pool applies IFRS 15, *Revenue from contracts with customers*, for its revenue arrangements.

(a) Sale of electricity and ancillary services

Revenues from the sale of electricity and ancillary services are recognized on an accrual basis in the period in which generation occurred, which is the point in time when control of the goods and services passes to the customer. Sale of electricity and ancillary services is measured at the fair value of the consideration received or receivable. The Corporation has elected to recognize revenue based on amounts invoiced.

The timing of revenue recognition does not result in any contract assets or liabilities and there are no unfulfilled performance obligations at any point in time. Furthermore, no significant judgments or estimates are required with respect to the recognition of revenue associated with the sale of electricity and ancillary services.

Notes to Financial Statements

Balancing Pool

(b) Consumer collection (allocation)

Upon adoption of IFRS 15, consumer collection revenue is recognized in the statement of income (loss) and comprehensive income (loss) on an accrual basis in the period in which amounts are charged (refunded) to electricity customers based on an annualized tariff amount, which is the point in time when control of the goods and services passes to the customer. Consumer collection revenue is measured at the fair value of the consideration received or receivable. The Corporation has elected to recognize revenue based on amounts invoiced.

The timing of revenue recognition does not result in any contract assets or liabilities and there are no unfulfilled performance obligations at any point in time. The Balancing Pool has applied judgment in the application of its accounting policy that the consumer collection (allocation) represents a contract with a customer in the scope of IFRS 15 (see Note 1).

Other Income (Expense) Recognition

(a) Hydro Power Purchase Arrangement

The Hydro PPA was recorded at the present value of the estimated future net receipts under this PPA. The increase in value of this asset with the passage of time (accretion) was recognized on an accrual basis. Any change in valuation as a result of changes in underlying assumptions was recognized in income (loss) from operating activities.

(b) Investment income

Investment income resulting from interest is recorded on an accrual basis when there is reasonable assurance as to its measurement and collectability.

(c) Payments (refunds) in Lieu of Tax

PILOT funds are accrued based on instalments received from or refunds paid to a municipal entity for a particular tax year. PILOT payments are calculated by the municipal entities and are subject to assessment and audit by Alberta Tax and Revenue Administration. Adjustments, if any, arising from audits, or other legal proceedings, are recorded in the current year, upon receipt.

Income Taxes

No provision has been made for current or deferred income tax as the Balancing Pool is exempt from Federal and Provincial income tax.

Cash and Cash Equivalents

Cash and cash equivalents are comprised of cash on deposit at the bank.

Trade and Other Receivables

Trade and other receivables are classified and measured at amortized cost less any impairment.

Hydro Power Purchase Arrangement

The Hydro PPA was a derivative financial instrument classified as and measured at fair value through profit or loss. The PPA was recorded as of the period end date at their fair value. Fair value was measured as the present value of the estimated future net payments to be received (or paid) under the arrangement and reflects management's best estimate based on generally accepted valuation techniques and supported by observable market prices and rates when available. Fair value for these contracts was based on forecasted future prices.

Notes to Financial Statements

Balancing Pool

Leases

The PPAs transfer to the Balancing Pool substantially all the benefits and some of the risks of ownership and therefore the arrangements were classified as finance leases, with the Corporation as the lessee. A lease is considered to be a finance lease when the terms of the lease transfer substantially all of the risks and rewards incidental to ownership of the leased assets to the lessee. Finance leases are capitalized at the lease's commencement at the fair value of the leased property. The Corporation recognized lease liabilities and right-of-use assets for the PPAs on adoption of *IFRS 16, Leases*. The Corporation has also recognized a lease liability and right-of-use asset for the office lease.

Lease liabilities for the PPAs were measured at the present value of the remaining lease payments. Lease liability for the office lease is measured at the present value of the remaining lease payments. The lease liability for the office lease has been discounted at the Balancing Pool's eighteen month (office lease term) borrowing rate of 0.45% (2020 – 1.8%).

Right-of-use assets were recognized for the PPAs on adoption of *IFRS 16, Leases*. The assets were amortized on a straight-line basis over the remaining life of the PPAs and will be amortized on a straight-line basis over the remaining term of the office lease.

Property, Plant and Equipment ("PP&E")

PP&E are stated at cost less accumulated depreciation and accumulated impairment losses. Cost includes expenditure directly attributable to the acquisition of the asset. When parts of an item of PP&E have different useful lives, they are accounted for as separate items (major components) of property, plant and equipment. Gains and losses on disposal of an item of property, plant, and equipment are determined by comparing the proceeds from disposal with the carrying amount of PP&E, and are recognized within other income in profit and loss. PP&E, which comprises office equipment, is depreciated on a straight-line basis over a three to five year useful life.

Impairment – Non-Financial Assets

For the purpose of impairment testing, non-financial assets are grouped together into the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets – a cash generating unit ("CGU").

The carrying amounts of non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment, such as decreased forward electricity prices. If any such indication exists, then the amount recoverable from the asset is estimated. The recoverable amount is the greater of the value in use or fair value less costs to dispose.

Value in use is based on the estimated net future cash flows discounted to their present value. The discounted cash flow is determined using a discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. The recoverable amount is generally computed by reference to the present value of the future cash flows. An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in the Statement of Income (loss) and Comprehensive Income (loss).

Impairment losses recognized in prior years are reassessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation and amortization, if no impairment loss had been permitted to be recognized.

Notes to Financial Statements

Balancing Pool

Impairment – Financial Assets

The Corporation applies IFRS 9, *Simplified approach to measuring expected credit losses*, which uses a lifetime expected loss allowance for all trade and other receivables. To measure the expected credit losses, trade receivables and other receivables have been grouped based on shared credit risk characteristics and the days past due.

Trade and other receivables are written off when there is no reasonable expectation of recovery. Indicators that there is no reasonable expectation of recovery include, amongst others, the failure of a debtor to engage in a repayment plan with the Corporation, and a failure to make contractual payments for a period of greater than 120 days past due.

No impairment provision has been recorded at December 31, 2021 related to trade and other receivables. The Corporation considers trade and other receivables to be low risk.

Reclamation and Abandonment Obligations

Reclamation and abandonment obligations include legal obligations requiring the Balancing Pool to fund the decommissioning of tangible long-lived assets such as generation and production facilities. A provision is made for the estimated cost of site restoration.

Reclamation and abandonment obligations are measured as the present value of management's best estimate of expenditures required to settle the present obligation at the period end date. Subsequent to the initial measurement, the obligations are adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as a finance expense. Increases / decreases due to changes in the estimated future cash flows are expensed. Actual costs incurred upon settlement of the reclamation and abandonment obligations are charged against the provision to the extent the provision was established.

The Balancing Pool's estimates of reclamation and abandonment obligations are based on reclamation standards that meet current regulatory requirements. The estimate of the total liability of future site restoration costs may be subject to change based on amendments to laws and regulations. Accordingly, the amount of the liability will be subject to re-measurement at each period end date.

The Balancing Pool has recorded an estimate of the cost to remediate certain Isolated Generating Unit sites in Alberta. Actual expenditures incurred to remediate these sites will reduce this liability and any increase in this liability will be charged to expense when estimated costs are known to exceed the remaining liability balance.

An amount has also been provided for the decommissioning of the H.R. Milner generating station which is being accreted annually; revisions to this estimate will be charged or credited to net results of income (loss).

Pursuant to Section 5 of the *Power Purchase Arrangements Regulation*, a PPA Owner may apply to the Alberta Utilities Commission ("AUC") to receive from the Balancing Pool the amount by which decommissioning costs related to a former PPA unit exceed the amount the PPA Owner collected from consumers before January 1, 2001 and subsequently through the PPA, provided that the unit has ceased generating electricity and the application is made within one year of the termination or expiration of the PPA. Section 5 of the *Power Purchase Arrangements Regulations* does not apply after December 31, 2018.

The reclamation and abandonment provision includes an estimate of the expected future costs associated with PPA decommissioning costs.

The discount rate used to value these liabilities is based upon the risk-free rate and adjusted for other risks associated with these liabilities.

Notes to Financial Statements

Balancing Pool

Other Provisions

Provisions for obligations are recognized when the Balancing Pool has a present legal or constructive obligation as a result of past events, it is probable that an outflow of resources will be required to settle the obligation and the amount can be reliably estimated. Provisions are not recognized for future operating losses.

Provisions are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the end of the reporting period. The discount rate used to determine the present value is a risk-free discount rate that reflects current market assessments of the time value of money. The increase in the provision due to the passage of time is recognized as finance expense.

4. Significant Accounting Judgments, Estimates and Assumptions

The timely preparation of the financial statements requires that management make estimates and assumptions and use judgment regarding the reported value of assets and liabilities, disclosures of contingent assets and liabilities at the date of the financial statements and the amounts of revenues and expenses reported for the year. Such estimates reflect management's best estimate of future events as of the date of the financial statements. These financial statements have, in management's opinion, been properly prepared using careful judgment within reasonable limits of materiality and within the framework of the significant accounting policies summarized below. Accordingly, actual results will differ from estimated amounts as future confirming events occur.

Critical Judgments in Applying Accounting Policies

Management has made critical judgments in applying accounting policies, including when concluding that the consumer collection (allocation) is accounted for as revenue (refund of revenue) from a contract with a customer (Note 1, 12).

These critical judgements have been made in the process of applying accounting policies and have a significant effect on the amounts recognized in the financial statements.

Key Sources of Estimation Uncertainty

Since the determination of certain assets, liabilities, revenues and expenses is dependent upon and determined by future events, the preparation of these financial statements requires the use of estimates and assumptions. These estimates and assumptions have been made using careful judgment. Actual results are likely to differ from the results derived using these estimates.

The following are items that have been derived using key assumptions concerning future outcomes and subject to several other key sources of estimation uncertainty. As a consequence, there is a significant risk of a material adjustment to the carrying amount of assets and liabilities within the next financial year:

- Reclamation and abandonment provision (Note 10)
- Contingent legal matters (Note 13)

In the opinion of management, these financial statements have been properly prepared in accordance with IFRS, within reasonable limits of materiality and the framework of the significant accounting policies summarized in Note 3 to the financial statements.

Notes to Financial Statements

Balancing Pool

5. Trade and Other Receivables

(in thousands of dollars)	**December 31, 2021**	December 31, 2020
Trade receivables	15,558	98,069
Retailer receivables	1,911	9,123
Other receivables	1,087	2,000
	18,556	109,192

On May 12, 2020, the Government of Alberta initiated a program that permitted residential, farm, and small commercial businesses to defer the payment of utility bills for 90 days. The Minister of Energy issued a Ministerial Order on April 22, 2020 directing the Balancing Pool to reserve $119.0 million for the 90-day utility payment deferral program to assist retailers with funding. At December 31, 2021 the Balancing Pool had issued $36.1 million in funding to the retailers and received repayments of $34.2 million from retailers and through the Utility Payment Deferral Program rate rider. The Utility Payment Deferral Program rate rider will continue until June 18, 2022, at which time all retailer receivable amounts will be collected in full.

At December 31, 2021, no accounts receivable amounts are past due.

6. Accounting for Financial Instruments

6. a) Risk Management Overview

The Balancing Pool's activities expose or exposed the Corporation to a variety of financial risks: market risk (including fluctuating market prices, plant availability, PPA capacity payments and interest rates), credit risk and liquidity risk. The Balancing Pool has developed Risk Management and Credit Policies that define the organization's tolerance for risk and set out procedures for quantifying and monitoring exposures. Exposures and compliance with the policies are regularly monitored by management and Board of Directors. Effective December 31, 2020, on the expiry of the PPAs, the Balancing Pool is no longer exposed to market prices, plant availability and capacity payments.

Market Risk – Power

i) ***Fluctuating Market Prices:*** Changes in the market price for electricity and ancillary services affected the amount of revenues that the Balancing Pool received from the thermal and Hydro PPAs. Electricity prices are volatile, and are affected by supply and demand, which in turn are influenced by fuel costs (e.g. natural gas prices), weather patterns, plant availability and power imports or exports. Economic activity is a key contributor to market price risk as it relates to the demand for electricity.

ii) ***Plant Availability:*** Changes in plant availability impacted the expected level of generation output and associated revenues and expenses of the Balancing Pool. According to the terms of the PPA, the Balancing Pool is entitled to availability incentive payments when the plant generated at levels below target availability. If the plant generated above the target availability, the Balancing Pool was required to make payments to the PPA Owner of the plant. The Balancing Pool was not entitled to availability incentive payments during an event of force majeure.

iii) ***Capacity Payment:*** The Balancing Pool was exposed to interest rate risk in relation to the annual capacity payments.

Notes to Financial Statements

Balancing Pool

Market Risk

i) ***Interest Rate Risk:*** The Balancing Pool is exposed to interest rate risk on the related party loan. There is the possibility that the value of the related party loan will change due to fluctuations in market interest rates.

ii) ***Counterparty Credit Risk:*** The Balancing Pool was exposed to counterparty credit risk. In the event of a default on payments from counterparties to the Hydro PPA, a financial loss may have been experienced by the Balancing Pool. Credit risk was managed in accordance with the Credit Policy which required that all counterparties maintain investment-grade status level. Status of counterparty credit was regularly monitored by management and the Audit and Finance Committee. The Balancing Pool had minimal credit risk related to its receivables and cash as they consisted primarily of amounts owing from the AESO, a government-related entity. The Balancing Pool does not consider any of the trade or long-term accounts receivable to be impaired or past due. Amounts funded under the Utility Payment Deferral Program are collected from retailers for the period of June 19, 2020 to June 18, 2021 and through a rate rider approved by the AUC from the period of June 19, 2021 to June 18, 2022. All retailer amounts funded will be collected back in full by June 18, 2022.

iii) ***Liquidity Risk:*** Liquidity risk is the risk that the Balancing Pool will not be able to meet its financial obligations as they fall due. To manage this risk, management forecasts cash flows for a period of 12 months and beyond and will adjust the consumer collection according to the *Balancing Pool Regulation* and borrow from the Government of Alberta. The changes to the EUA, enacted in December of 2016, provide the Balancing Pool with the capacity to borrow from the Government of Alberta (Note 17).

The following below analyzes the Balancing Pool's financial and other liabilities into relevant maturity groupings based on the remaining period from the period end date to the contract maturity date.

December 31, 2021

(in thousands of dollars)	**1 year**	**2 - 5 years**	**Total**
Trade payables	658	-	658
Other accrued liabilities	4,018	6,792	10,810
Related party loan – principal	206,894	499,130	706,024
Related party loan – interest	58	4,743	4,801
Reclamation and abandonment	169	41,988	42,157
Lease liability	25	2	27
Total	211,822	552,655	764,477

December 31, 2020

(in thousands of dollars)	1 year	2 - 5 years	Total
Trade payables	81,284	-	81,284
Other accrued liabilities	318,428	-	318,428
Related party loan – principal	201,184	498,802	699,986
Related party loan – interest	1,748	4,744	6,492
Reclamation and abandonment	263	38,188	38,451
Lease liability	91	-	91
Total	602,998	541,734	1,144,732

Notes to Financial Statements

Balancing Pool

6. b) Fair Value Hierarchy

Financial instruments carried at fair value are categorized as follows:

December 31, 2021

(in thousands of dollars)	**Quoted prices in active markets for identical assets**	**Significant other observable inputs**	**Significant unobservable inputs**	**Total**
Assets	Level 1	Level 2	Level 3	
Cash and cash equivalents	32,963	-	-	32,963
	32,963	-	-	32,963

December 31, 2020

(in thousands of dollars)	Quoted prices in active markets for identical assets	Significant other observable inputs	Significant unobservable inputs	Total
Assets	Level 1	Level 2	Level 3	
Cash and cash equivalents	223,737	-	-	223,737
	223,737	-	-	223,737

i) Level 1

Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities.

ii) Level 2

Assets and liabilities in Level 2 include valuations using inputs other than Level 1 quoted prices for which all significant inputs are observable, either directly or indirectly. Fair values for fixed income investments were determined using quoted market prices in active markets.

iii) Level 3

Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. Changes in valuation methods may result in transfers into or out of an assigned level. There were no transfers between Level 3 and Level 2. The Hydro PPA value was determined using discounted cash flow forecast methods and supported by observable market prices when available. Methodologies were developed to determine the fair value for the Hydro PPA contract based on forecast of the hourly electricity market price in Alberta's hourly market using proprietary third-party models. Management reviewed the discounted cash flow forecasts on an annual basis.

Notes to Financial Statements

Balancing Pool

7. Right-of-Use Assets

(in thousands of dollars)	Genesee PPA	Keephills PPA	Sheerness PPA	Office Lease	Total
At January 1, 2020	129,103	75000	85,666	241	290,010
Amortization and depreciation	(129,238)	(75,684)	(84,893)	(152)	(289,967)
Reassessment of lease liability	135	684	(773)	-	46
At December 31, 2020	-	-	-	89	89
At January 1, 2021	-	-	-	89	89
Amortization and depreciation	-	-	-	(99)	(99)
Additions	-	-	-	37	37
At December 31, 2021	-	-	-	27	27
Less: current portion	-	-	-	(25)	(25)
	-	-	-	2	2

During 2021, $0.1 million (2020 - $290.0 million) in amortization and depreciation was recorded. In July 2021, the Balancing Pool signed an 18 month office lease resulting in an addition of $0.04 million. Effective December 31, 2020, the Genesee, Keephills and Sheerness PPAs expired.

8. Finance Expense

(in thousands of dollars)	2021	2020
Interest expense – related party loan	13,924	15,326
Interest expense – lease liability	1	7,412
Accretion expense – reclamation and abandonment	58	572
	13,983	23,310

9. Trade Payable and Other Accrued Liabilities

(in thousands of dollars)	2021	2020
Trade payables	658	81,284
Accrued liabilities – Greenhouse gas obligation	-	237,852
Accrued liabilities – Line loss provision	511	67,902
Accrued liabilities – Mandated costs	3,349	3,570
Accrued liabilities – Other	6,950	9,104
	11,468	399,712

Notes to Financial Statements

Balancing Pool

10. Reclamation and Abandonment Provision

(in thousands of dollars)	H.R. Milner Generating Station	Isolated Generation Sites	Sundance A Generating Station	Total
At January 1, 2020	8,908	1,978	21,973	32,859
Net increase (decrease) in liability	1,552	(20)	5,461	6,993
Liabilities paid in year	(399)	(1,574)	-	(1,973)
Accretion expense	155	34	383	572
At December 31, 2020	10,216	418	27,817	38,451
Less: Current portion	(177)	(86)	-	(263)
	10,039	332	27,817	38,188
At January 1, 2021	10,216	418	27,817	38,451
Increase (decrease) in liability	(529)	104	4,690	4,265
Liabilities paid in year	(226)	(391)	-	(617)
Accretion expense	15	1	42	58
At December 31, 2021	9,476	132	32,549	42,157
Less: Current portion	(100)	(69)	-	(169)
	9,376	63	32,549	41,988

a) Decommissioning Costs of H.R. Milner Generating Station

Under the Asset Sale Agreement for the H.R. Milner generating station between the Balancing Pool and ATCO Power Ltd ("ATCO"), which was executed in 2001, the Balancing Pool assumed the liability for the costs of decommissioning the station at the end of operations. When the asset was subsequently re-sold to Milner Power Limited Partnership in 2004, the Balancing Pool retained the liability for decommissioning the generating station. In 2011, a bilateral agreement was reached with Milner Power Limited Partnership wherein the Balancing Pool's exposure to future decommissioning costs was capped at $15.0 million. As at December 31, 2021, a total of $4.9 million has been paid for decommissioning the Milner generating site, leaving a balance of $10.1 million remaining. These costs have been discounted at the risk-free rate of 0.76% (2020 – 0.15%). At December 31, 2021, the provision decreased by $0.5 million (2020 – $1.6 million increase) to reflect a change in the discount rate. Expenditures of $0.2 million were incurred in 2021 (2020 – $0.4 million).

b) Isolated Generation Sites

Under the *Isolated Generating Units and Customer Choice Regulations of the EUA*, the Balancing Pool is liable for the reclamation and abandonment costs associated with various Isolated Generation sites. Expenditures of $0.4 million (2020 – $1.6 million) were incurred in 2021. Pursuant to the Negotiated Settlement Agreements approved by the AUC, the ultimate payment of these costs must be reviewed and approved by the Remediation Review Committee. The Remediation Review Committee was established to monitor, verify and approve all costs associated with the reclamation and abandonment of the Isolated Generation sites. Estimated reclamation and abandonment costs have been discounted at 0.76% (2020 – 0.15%). The provision is based upon management's best estimate and the timing of the costs. Management anticipates the Isolated Generation projects will conclude at the end of 2023.

Notes to Financial Statements

Balancing Pool

c) Decommissioning Costs of PPA Units

Pursuant to Section 5 of the *Power Purchase Arrangements Regulation*, a PPA Owner may apply to the Alberta Utilities Commission ("AUC") to receive from the Balancing Pool the amount by which decommissioning costs related to a former PPA unit exceed the amount the PPA Owner collected from consumers before January 1, 2001 and subsequently through the PPA, provided that the unit has ceased generating electricity and the application is made within one year of the termination or expiration of the PPA. Section 5 of the *Power Purchase Arrangements Regulations* does not apply after December 31, 2018.

In December 2018, TransAlta submitted an application to the AUC as well as two amendments to decommission Sundance unit A. In December 31, 2021, the Balancing Pool recorded a $4.3 million increase (2020 – $5.5 million increase) to the provision for decommissioning the Sundance A unit. The provision for Sundance A is based upon management's best estimate of decommissioning costs. Estimated decommissioning costs were discounted at 0.76% (2020 – 0.15%). The AUC will determine the amount owed to TransAlta. See also Note 13.

11. Lease Liability

(in thousands of dollars)	Genesee PPA	Keephills PPA	Sheerness PPA	Office Lease	Total
At January 1, 2020	165,651	112,096	132,125	244	410,116
Finance expense	3,001	2,031	2,377	3	7,412
Lease payments	(168,786)	(114,811)	(133,730)	(156)	(417,483)
Reassessment of lease liability	134	684	(772)	-	46
At December 31, 2020	-	-	-	91	91
At January 1, 2021	-	-	-	91	91
Finance expense	-	-	-	1	1
Lease payments	-	-	-	(102)	(102)
Additions	-	-	-	37	37
At December 31, 2021	-	-	-	27	27
Less: current portion	-	-	-	(25)	(25)
	-	-	-	2	2

The Balancing Pool has recognized lease liabilities in relation to the office lease. The lease liabilities have been discounted using a rate of 0.45% (2020 – 1.8%).

12. Capital Management

The Balancing Pool's objective when managing capital is to operate as per the requirements of the EUA, which requires the Balancing Pool to operate with no profit or loss and no share capital and to forecast its revenues, expenses, and cash flows. Any excess or shortfall of funds in the accounts is to be allocated to, or provided by, electricity consumers over time. During 2016, the Alberta Government enacted amendments to the *Balancing Pool Regulation* that defined the method by which the Balancing Pool would calculate the amounts to be allocated to, or provided by, electricity consumers through to 2030. In January 2017, the Balancing Pool signed a loan agreement with the Government of Alberta. The loan agreement was put in place through Alberta Treasury Board and Finance to fund operating losses of the Balancing Pool, including obligations associated with the terminated PPAs.

Notes to Financial Statements

Balancing Pool

A reconciliation of the opening and closing Balancing Pool deferral account is provided below.

Balancing Pool Deferral Account *(in thousands of dollars)*	**2021**	**2020**
Deferral account, beginning of year	(811,699)	(774,625)
Change to the Balancing Pool deferral account	98,776	(37,074)
Deferral account, end of year	(712,924)	(811,699)

In December 2020, the Board of Directors approved a 2021 consumer collection of $2.30/MWh for a total collection from electricity consumers of $135.8 million in accordance with the *Balancing Pool Regulation*. In October 2021, the Board of Directors approved a 2022 consumer collection of $2.20/MWh for an estimated total collection from electricity consumers of $132.0 million in accordance with the *Balancing Pool Regulation*.

13. Contingencies and Commitments

Reclamation and Abandonment

TransAlta has submitted an application as well as two amendments to the AUC to decommission Sundance A and is seeking $76.0 million (2020 - $46.0 million) in funding from the Balancing Pool. The Balancing Pool disagrees with several aspects of the application. The Balancing Pool has a provision of $32.5 million (2020 - $27.8 million) to decommission Sundance A. The final amount due will be determined by the AUC.

Legal Claim

On June 12, 2019, the Balancing Pool received a statement of claim from a power producer seeking $17.5 million in damages from the Balancing Pool. The Balancing Pool considers the claim to be without merit. Section 92 of the *Electric Utilities Act* provides the Balancing Pool with strong liability protection for such claims.

On August 6, 2021, the Court of Queen's Bench granted the Balancing Pool's application to strike the entire claim. The claimant appealed the ruling. On March 3, 2022, the Court of Queen's Bench dismissed the appeal and the claim was struck entirely. On April 1, 2022, the claimant filed and served a Notice of Appeal with the Alberta Court of Appeal.

As at December 31, 2021, no contingent liability has been recorded (2020 - $nil).

Legal Claim – Line Loss Proceeding

On January 27, 2021, the Balancing Pool received a statement of claim from a power producer related to the line loss rule proceeding and is seeking $53.2 million (2020 - $10.3 million) in damages from the Balancing Pool. The Balancing Pool has filed its statement of defense and considers the claim to be without merit.

At December 31, 2021, no contingent liability has been recorded (2020 - $nil).

Arbitration - Line Loss Proceeding

In April 2021, a power producer gave notice to the Balancing Pool of a formal arbitration proceeding in regards to the historical line loss proceeding. The power producer is seeking $56.6 million from the Balancing Pool for historical line loss amounts invoiced by the AESO to the power producer. The Balancing Pool considers the matter to be without merit.

At December 31, 2021, no contingent liability has been recorded.

Notes to Financial Statements

Balancing Pool

MSA Investigation

On August 5, 2020, the Balancing Pool received a Notice of Investigation from the Market Surveillance Administrator ("MSA"). The MSA investigated to assure itself that the Balancing Pool was complying with all of its obligations and ensuring the Balancing Pool acted within the limits of the PPA framework and in accordance with the laws that govern Alberta. The MSA has discontinued the investigation as disclosed in their Q4 2021 quarterly report.

Other Legal Claims

The Balancing Pool is involved in other legal claims and legal proceedings arising in the ordinary course of business. Although the outcome of such matters cannot be predicted with certainty, the Corporation does not consider the Balancing Pool's exposure to litigation to be material to these financial statements. Accruals for litigation, claims and assessments are recognized if the Balancing Pool determines that the loss is probable and the amount can be reasonably estimated. The Balancing Pool believes it has made adequate provisions for such legal claims.

14. Cost of Sales

(in thousands of dollars)	**2021**	**2020**
Cost of Power Purchase Arrangements	7,278	488,956
Small scale generator costs	52	147
Gain on the retirement of emission credits	-	(2,283)
Amortization and depreciation on right-of-use assets	107	289,975
	7,437	776,795

In 2021, the Balancing Pool settled the final amounts for the thermal PPAs and Hydro PPA for capacity payment true-ups and historical line loss true-ups resulting in a net expense of $7.3 million.

15. Commercial Dispute costs (recovery)

(in thousands of dollars)	**2021**	**2020**
Force Majeure and commercial dispute (recovery)	(12,000)	-
Commercial dispute costs	1,764	2,320
	(10,236)	2,320

In 2021, the Balancing Pool reached a negotiated settlement with a counterparty and recovered $12 million related to a previous Force Majeure event and other disputed commercial matters.

16. Related Party Transactions

Key Management Compensation

Key management includes members of the Board of the Balancing Pool and the Chief Executive Officer. The compensation paid or payable to key management for services is shown below.

Key Management Compensation *(in thousands of dollars)*	**2021**	**2020**
Salaries, other short-term employee benefits and severance	480	519
Total	480	519

Notes to Financial Statements

Balancing Pool

Government-Related Entity

The Balancing Pool considers itself to be a government-related entity as defined by IAS 24 – *Related Party Disclosures* and applies the exemption from the disclosure requirements of Paragraph 18 of IAS 24 – *Related Party Disclosures.* The members of the Board are appointed by the Minister of Energy of the Government of Alberta. The financial information of the Balancing Pool is being consolidated by the Ministry of Energy.

In January 2017, the Balancing Pool signed a loan agreement with the Government of Alberta. The loan agreement was put in place through Alberta Treasury Board and Finance to fund operating losses of the Balancing Pool, including obligations associated with the terminated PPAs. The loan agreement will remain until December 31, 2030 when all outstanding loan amounts are due to be paid back to the provincial government. As the Balancing Pool has short-term and long-term related party notes outstanding which mature prior to December 31, 2030, the Balancing Pool expects to repay maturing notes through its consumer collection (Note 12) or refinance maturing notes outstanding with the Government of Alberta (Note 17), subject to the terms of the loan agreement. Details of the Balancing Pool's related party loans outstanding are as follows:

(in thousands of dollars)	**Interest Rate**	**December 31, 2021**
Long-term note due on September 13, 2023	2.65%	503,873
Short-term discount note due on January 20, 2022	0.19%	54,967
Short-term discount note due on March 15, 2022	0.30%	151,985
		710,825
Less: Current portion		(206,952)
		503,873

(in thousands of dollars)	Interest Rate	December 31, 2020
Long-term note due on September 13, 2023	2.65%	503,546
Short-term discount note due on February 18, 2021	0.14%	74,986
Short-term discount note due on March 26, 2021	0.18%	127,946
		706,478
Less: Current portion		(202,932)
		503,546

At December 31, 2021, the Balancing Pool had $710.8 million (2020 – $706.5 million) in short-term discount and long-term notes issued to the Government of Alberta, including accrued interest of $5.6 million (2020 – $6.5 million). During 2021, payments of $9.6 million (2020 - $14.8 million payment) were remitted on the outstanding loan. Fair value of the loan is the same as the amortized cost of borrowing. During 2021, interest of $13.6 million was paid on the related party loan (2020 – $15.3 million).

Directed by the Minister of Energy, the Balancing Pool is mandated to make payments to the Office of the Utilities Consumer Advocate ("UCA") to cover 80% of their annual operating costs and to the Transmission Facilities Cost Monitoring Committee ("TFCMC") to cover 100% of their annual costs. In 2021, the Balancing Pool expensed $3.8 million (2020 – $5.0 million) for the UCA and a recovery of $0.01 million (2020 – $0.1 million) for the TFCMC. The Balancing Pool anticipates no further funding will be required for the TFCMC.

Notes to Financial Statements

Balancing Pool

The Balancing Pool also considers the AESO a government-related entity. The EUA requires the Balancing Pool to forecast its revenues and expenses with any excess or shortfall of funds in the accounts to be allocated to, or provided by, electricity consumers over time. Pursuant to the EUA, the AESO facilitates the collection or distribution of any excess or shortfall through an annualized amount included in the AESO's transmission tariff. In 2021, the Balancing Pool collected $135.8 million (2020 – $145.4 million) from electricity consumers through the AESO's transmission tariff.

17. Subsequent Events

Related Party Transactions

On January 20, 2022 and March 15, 2022 the maturing related-party short-term notes were re-financed with the terms noted below.

(in thousands of dollars)	Interest Rate	Amount re-financed
Short-term discount note due on April 20, 2022	0.58%	137,000
Short-term discount note due on June 13, 2022	0.77%	40,000

Post-Closure Stewardship Fund

Financial Statements

For the Year Ended March 31, 2022

Table of Contents

Auditor General OF ALBERTA

Independent Auditor's Report

To the Minister of Energy

Report on the Financial Statements

Opinion

I have audited the financial statements of the Post-Closure Stewardship Fund, which comprise the statement of financial position as at March 31, 2022, and the statements of operations, change in net financial assets, and cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In my opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Post-Closure Stewardship Fund as at March 31, 2022, and the results of its operations, its changes in net financial assets, and its cash flows for the year then ended in accordance with Canadian public sector accounting standards.

Basis for opinion

I conducted my audit in accordance with Canadian generally accepted auditing standards. My responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of my report. I am independent of the Post-Closure Stewardship Fund in accordance with the ethical requirements that are relevant to my audit of the financial statements in Canada, and I have fulfilled my other ethical responsibilities in accordance with these requirements. I believe that the audit evidence I have obtained is sufficient and appropriate to provide a basis for my opinion.

Other information

Management is responsible for the other information. The financial statements of the Post-Closure Stewardship Fund are included in the *Annual Report of the Ministry of Energy*. The other information comprises the information included in the *Annual Report of the Ministry of Energy* relating to the Post-Closure Stewardship Fund, but does not include the financial statements of the Post-Closure Stewardship Fund and my auditor's report thereon. The *Annual Report of the Ministry of Energy* is expected to be made available to me after the date of this auditor's report.

My opinion on the financial statements does not cover the other information and I do not express any form of assurance conclusion thereon.

In connection with my audit of the financial statements, my responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or my knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work I will perform on this other information, I conclude that there is a material misstatement of this other information, I am required to communicate the matter to those charged with governance.

Responsibilities of management and those charged with governance for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with Canadian public sector accounting standards, and for such internal control as management determines is necessary to enable the preparation of the financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Post-Closure Stewardship Fund’s ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless an intention exists to liquidate or to cease operations, or there is no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Post-Closure Stewardship Fund’s financial reporting process.

Auditor's responsibilities for the audit of the financial statements

My objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes my opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, I exercise professional judgment and maintain professional skepticism throughout the audit. I also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for my opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Post-Closure Stewardship Fund’s internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management’s use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Post-Closure Stewardship Fund’s ability to continue as a going concern. If I conclude that a material uncertainty exists, I am required to draw attention in my auditor’s report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify my opinion. My conclusions are based on the audit evidence obtained up to the date of my auditor’s report. However, future events or conditions may cause the Post-Closure Stewardship Fund to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

I communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that I identify during my audit.

[Original signed by W. Doug Wylie FCPA, FCMA, ICD.D]
Auditor General

June 2, 2022
Edmonton, Alberta

Statement of Operations

Post-Closure Stewardship Fund
Year Ended March 31, 2022
(in thousands)

	2022		2021
	Budget	Actual	Actual
Revenue			
Injection Levy (Note 3)	$ 230	$ 218	$ 219
Investment Income	-	4	6
Net Operating Results	230	222	225

The accompanying notes are part of these financial statements.

Statement of Financial Position

Post-Closure Stewardship Fund
As At March 31, 2022
(in thousands)

		2022		2021
Assets				
Cash (Note 4)	$	1,561	$	1,316
Accounts Receivable		110		133
Net Financial Assets	**$**	**1,671**	**$**	**1,449**
Net Financial Assets at Beginning of Year	$	1,449	$	1,224
Annual Operating Results		222		225
Net Financial Assets at End of Year	**$**	**1,671**	**$**	**1,449**

The accompanying notes are part of these financial statements.

Statement of Change in Net Financial Assets

Post-Closure Stewardship Fund
Year Ended March 31, 2022
(in thousands)

	2022		2021
	Budget	Actual	Actual
Annual Operating Results	$ 230	$ 222	$ 225
Increase in Net Financial Assets	$ 230	$ 222	$ 225
Net Financial Assets at Beginning of Year	-	1,449	1,224
Net Financial Assets at End of Year	**$ 230**	**$ 1,671**	**$ 1,449**

The accompanying notes are part of these financial statements.

Statement of Cash Flows

Post-Closure Stewardship Fund
Year Ended March 31, 2022
(in thousands)

	2022	2021
Operating Transactions		
Net Operating Results	$ 222	$ 225
Decrease in Accounts Receivable	23	8
Increase in Cash and Cash Equivalents	**$ 245**	**$ 233**
Cash and Cash Equivalents at Beginning of Year	1,316	1,083
Cash and Cash Equivalents at End of Year	**$ 1,561**	**$ 1,316**

The accompanying notes are part of these financial statements.

Notes to the Financial Statements

Post-Closure Stewardship Fund
March 31, 2022

NOTE 1 AUTHORITY & PURPOSE

The Post-Closure Stewardship Fund operates under the *Mines and Minerals Act* (MMA), chapter M-17.

The MMA provides an option to the Minister to issue a Closure Certificate to an approved operator after the final injection of captured carbon dioxide has been completed and after satisfying the closure period that is to be specified in regulations. There is no liability to the Fund until such a Closure Certificate has been issued.

The Fund was established to address certain long-term liabilities that may arise from approved projects for the injection of captured carbon dioxide into subsurface reservoirs for sequestration subsequent to the issuance of a Closure Certificate.

The Injection Levy Rate(s) are set through Ministerial Orders and are reviewed on a regular schedule. Based on the result of the review, the rate(s) will be amended as necessary.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES

These financial statements are prepared in accordance with Canadian Public Sector Accounting Standards.

(a) **Basis of Financial Reporting**

Revenues
Revenues are reported on the accrual basis of accounting. The volume of carbon dioxide injected is based upon reported injection provided by the operator. Third party verification on the volume of injection will take place in the month of October, for injection to September 30. The Injection Levy is calculated based on the net present value of estimated future costs arising from the injection.

Financial Assets
Financial assets are assets that could be used to discharge existing liabilities or finance future operations and are not for consumption in the normal course of operations.

NOTE 3 INJECTION LEVY

The Injection Levy is set aside for Post-Closure Care of the injection site. Post-Closure Care occurs after the issuance of the Closure Certificate and includes the continual monitoring costs of the captured carbon dioxide injection sites and any remediation of the sites that may be required.

At March 31, 2022, there is only one approved carbon dioxide injection site. The estimated present value of the future costs for this site, based on modeling of potential requirement under current technology, is $4.7 million. Currently, approximately 28% of the site's capacity has been used. The project is expected to inject for a 25-year period.

As the site remains active and no Closure Certificate has been issued, there is no expectation of any withdrawals from the Fund at this time.

NOTE 4 CASH

Cash is represented by funds held within the Post-Closure Stewardship Fund's Consolidated Cash Investment Trust Fund (CCITF) bank account. The fund earns interest at an effective rate of 0.24% per annum (2021 - 0.51%).

NOTE 5 APPROVAL OF FINANCIAL STATEMENTS

The Deputy Minister and the Senior Financial Officer approve these financial statements.

Canadian Energy Centre Ltd.

Financial Statements

Year Ended March 31, 2022

Table of Contents

Auditor General
OF ALBERTA

Independent Auditor's Report

To the Board of Directors of the Canadian Energy Centre Ltd.

Report on the Financial Statements

Opinion

I have audited the financial statements of the Canadian Energy Centre Ltd. (the CEC), which comprise the statement of financial position as at March 31, 2022, and the statements of operations, change in (net debt) net financial assets, and cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In my opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the CEC as at March 31, 2022, and the results of its operations, its changes in net financial assets, and its cash flows for the year then ended in accordance with Canadian public sector accounting standards.

Basis for opinion

I conducted my audit in accordance with Canadian generally accepted auditing standards. My responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of my report. I am independent of the CEC in accordance with the ethical requirements that are relevant to my audit of the financial statements in Canada, and I have fulfilled my other ethical responsibilities in accordance with these requirements. I believe that the audit evidence I have obtained is sufficient and appropriate to provide a basis for my opinion.

Other information

Management is responsible for the other information. The other information comprises the information included in the *Annual Report*, but does not include the financial statements and my auditor's report thereon. The *Annual Report* is expected to be made available to me after the date of this auditor's report.

My opinion on the financial statements does not cover the other information and I do not express any form of assurance conclusion thereon.

In connection with my audit of the financial statements, my responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or my knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work I will perform on this other information, I conclude that there is a material misstatement of this other information, I am required to communicate the matter to those charged with governance.

Responsibilities of management and those charged with governance for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with Canadian public sector accounting standards, and for such internal control as management determines is necessary to enable the preparation of the financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the CEC’s ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless an intention exists to liquidate or to cease operations, or there is no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the CEC’s financial reporting process.

Auditor's responsibilities for the audit of the financial statements

My objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes my opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, I exercise professional judgment and maintain professional skepticism throughout the audit. I also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for my opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the CEC's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management’s use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the CEC’s ability to continue as a going concern. If I conclude that a material uncertainty exists, I am required to draw attention in my auditor’s report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify my opinion. My conclusions are based on the audit evidence obtained up to the date of my auditor’s report. However, future events or conditions may cause the CEC to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

I communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that I identify during my audit.

[Original signed by W. Doug Wylie FCPA, FCMA, ICD.D]

Auditor General

May 9, 2022

Edmonton, Alberta

Statement of Operations

Canadian Energy Centre Ltd.
Year Ended March 31, 2022

	2022 Budget (Note 4)	2022 Actual	2021 Actual
Revenues			
Government transfers			
Government of Alberta grants	$ 7,701,784	$ 7,701,784	$ 1,673,443
	7,701,784	**7,701,784**	**1,673,433**
Expenses (Schedule 1)			
Resource Development and Management	10,326,557	4,158,577	3,734,983
	10,326,557	**4,158,577**	**3,734,983**
Annual operating (deficit) / surplus	(2,624,773)	3,543,207	(2,061,540)
Annual (deficit) / surplus	**(2,624,773)**	**3,543,207**	**(2,061,540)**
Accumulated (deficit) surplus at beginning of year	(2,911,552)	974,187	3,035,727
Accumulated (deficit) surplus at end of year (Note 7)	**$ (5,536,325)**	**$ 4,517,394**	**$ 974,187**

The accompanying notes and schedules are part of these financial statements.

Statement of Financial Position

Canadian Energy Centre Ltd.
As At March 31, 2022

	2022	2021
Financial Assets		
Cash	$ 4,742,986	$ 1,846,504
Accounts receivable	122,380	99,875
	4,865,366	**1,946,379**
Liabilities		
Accounts payable and other accrued liabilities (Note 6)	654,126	1,015,679
	654,126	**1,015,679**
Net Financial Assets	**4,211,240**	**930,700**
Non-Financial Assets		
Prepaid expenses	306,154	43,487
	306,154	**43,487**
Net Assets		
Accumulated surplus (Note 7)	**4,517,394**	974,187
	$ 4,517,394	**$ 974,187**

Contingent liabilities (Note 9)
Contractual obligations (Note 10)

The accompanying notes and schedules are part of these financial statements.

Approved by:

[Original signed by Hon. Sonya Savage]
Chair of the Board of Directors

Approved by:

[Original signed by Tom Olsen]
Chief Executive Officer/Managing Director

Statement of Change in (Net Debt) Net Financial Assets

Canadian Energy Centre Ltd.
Year Ended March 31, 2022

	2022		2021
	Budget	**Actual**	**Actual**
Annual (deficit) / surplus	**$ (2,624,773)**	**$ 3,543,207**	**$ (2,061,540)**
Increase in prepaid expenses	-	(262,667)	(12,002)
(Decrease) / increase in (net debt)/net financial assets	**(2,624,773)**	**3,280,540**	**(2,073,542)**
(Net debt)/net financial assets at beginning of year	**(2,911,552)**	**930,700**	**3,004,242**
(Net debt)/net financial assets at end of year	**$ (5,536,325)**	**$ 4,211,240**	**$ 930,700**

The accompanying notes and schedules are part of these financial statements.

Statement of Cash Flows

Canadian Energy Centre Ltd.
Year Ended March 31, 2022

	2022	2021
Operating transactions		
Annual surplus/(deficit)	$ 3,543,207	$ (2,061,540)
(Increase)/decrease in accounts receivable	(22,505)	968,701
Increase in prepaid expenses	(262,667)	(12,002)
Increase in accounts payable and other accrued liabilities	(361,553)	244,087
Cash provided by (applied to) operating transactions	**2,896,482**	**(860,754)**
Increase/(decrease) in cash	**2,896,482**	**(860,754)**
Cash at beginning of year	**1,846,504**	**2,707,258**
Cash at end of year	**$ 4,742,986**	**$ 1,846,504**

The accompanying notes and schedules are part of these financial statements.

Notes to the Financial Statements

Canadian Energy Centre Ltd.
Year Ended March 31, 2022

Note 1 AUTHORITY

The Canadian Energy Centre Ltd. (the “Corporation”) is a provincial corporation incorporated under the *Business Corporations Act* (Alberta) on October 9, 2019.

The Corporation is wholly owned by Her Majesty the Queen in the Right of Alberta as represented by the Minister of Energy. It is governed by a Board of Directors appointed by the Province. The Board consists of three Cabinet Ministers appointed by the Government of Alberta.

The mandate of the Corporation is to promote Canada as the supplier of choice for the world’s growing demand for responsibly produced energy.

As a provincial corporation, the Corporation is exempt from income taxes under the *Income Tax Act.*

Note 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES

These financial statements are prepared in accordance with Canadian Public Sector Accounting Standards.

(a) Basis of Financial Reporting

Revenues

All revenues are reported on the accrual basis of accounting.

Government Transfers
Transfers from all governments are referred to as government transfers.

Government transfers and associated externally restricted investment income are recognized as deferred contributions if the eligibility criteria for use of the transfer, or the stipulations together with the Corporation’s actions and communications as to the use of the transfer, create a liability. These transfers are recognized as revenue as the stipulations are met and, when applicable, the Corporation complies with its communicated use of these transfers.

Notes to the Financial Statements

Canadian Energy Centre Ltd.
Year Ended March 31, 2022

Note 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (Cont'd)

(a) Basis of Financial Reporting (Cont'd)

All other government transfers, without stipulations for use of the transfer, are recognized as revenue when the transfer is authorized, and the Corporation meets the eligibility criteria (if any).

Expenses

Expenses are reported on an accrual basis. The cost of all goods consumed and services received during the year are expensed.

Valuation of Financial Assets and Liabilities

The Corporation's financial assets and liabilities are generally measured as follows:

Financial Statement Component	Measurement
Cash	Cost
Accounts receivable	Lower of cost or net recoverable value
Accounts payable and accrued liabilities	Cost

The Corporation does not have any financial instruments classified in the fair value category and does not hold derivative contracts. Therefore, these statements do not present a statement of remeasurement gains and losses as the Corporation is not exposed to remeasurement gains and losses.

Financial Assets

Financial assets are assets that could be used to discharge existing liabilities or finance future operations and are not for consumption in the normal course of operations.

Notes to the Financial Statements

Canadian Energy Centre Ltd.
Year Ended March 31, 2022

Note 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (Cont'd)

(a) Basis of Financial Reporting (Cont'd)

Financial assets are the Corporation's financial claims on external organizations and individuals at the year end.

Cash
Cash comprises of cash on hand and demand deposits.

Accounts receivable
Accounts receivable are recognized at the lower of cost or net recoverable value. A valuation allowance is recognized when recovery is uncertain.

Liabilities

Liabilities are present obligations of the Corporation to external entities and individuals arising from past transactions or events occurring before the year end, the settlement of which is expected to result in the future sacrifice of economic benefits. They are recognized when there is an appropriate basis of measurement and management can reasonably estimate the amounts.
They include accounts payable and accrued liabilities.

Non-Financial Assets

Non-financial assets are acquired, constructed, or developed assets that do not normally provide resources to discharge existing liabilities, but instead:

(a) are normally employed to deliver the Corporation services;
(b) may be consumed in the normal course of operations; and
(c) are not for sale in the normal course of operations.

Non-financial assets are limited to prepaid expenses.

Notes to the Financial Statements

Canadian Energy Centre Ltd.
Year Ended March 31, 2022

Note 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (Cont'd)

(a) Basis of Financial Reporting (Cont'd)

Tangible Capital Assets
Tangible capital assets are recognized at cost less accumulated amortization, which includes amounts that are directly related to the acquisition, design, construction, development, improvement, or betterment of the assets. Cost includes overhead directly attributable to construction and development, as well as interest costs that are directly attributable to the acquisition or construction of the asset. The cost, less residual value, of the tangible capital assets, excluding land, is amortized on a straight-line basis over their estimated useful lives.

The capitalization threshold for all capital assets is $2,000. The Corporation, however, does not have any capital assets. Therefore, there is no tangible capital assets reported in the financial statements.

Prepaid expenses
Prepaid expenses are recognized at cost and amortized based on the terms of the agreement.

Note 3 FUTURE CHANGES IN ACCOUNTING STANDARDS

During the fiscal year 2022-23, the Corporation will adopt the following new accounting standard of the Public Sector Accounting Board:

- **PS 3280 Asset Retirement Obligations**
  This accounting standard provides guidance on how to account for and report liabilities for retirement of tangible capital assets. The Corporation plans to adopt this accounting standard on a modified retroactive basis, consistent with the transitional provisions in PS 3280, and information presented for comparative purposes will be restated. The impact of the adoption of this accounting standard on the financial statements is currently being analyzed.

In addition to the above, the Public Sector Accounting Board has approved the following accounting standards, which are effective for fiscal years starting on or after April 1, 2023.

- **PS 3400 Revenue**
  This accounting standard provides guidance on how to account for and report on revenue, and specifically, it differentiates between revenue arising from exchange and non-exchange transactions.

Notes to the Financial Statements

Canadian Energy Centre Ltd.
Year Ended March 31, 2022

Note 3 FUTURE ACCOUNTING CHANGES (Cont'd)

- **PS 3160 Public Private Partnerships**
  This accounting standard provides guidance on how to account for public private partnerships between public and private sector entities, where the public sector entity procures infrastructure using a private sector partner.

The Corporation has not yet adopted these standards. Management is currently assessing the impact of these standards on the Corporation's financial statements.

Note 4 BUDGET

A budget of $10,326,557 was approved by the Board on April 20, 2021.
In addition, $1,700,000 was approved by the Board for committed additional expenses on March 10, 2022.
Revenue budget reported in the Statement of Operations reflects actual cash received during the Year.
Expenses budget reported in the Statement of Operations reflects the budget and reclassifications required for more consistent presentation with current and prior year results.

Note 5 FINANCIAL RISK MANAGEMENT

The Corporation is exposed to some financial risks. These financial risks include credit risk and liquidity risk.

(a) Credit Risk

Credit risk is the risk of loss arising from the failure of a counterparty to fully honour its financial obligations with the Corporation. Credit risk on accounts receivable is considered low.

As of March 31, 2022, the balance of accounts receivable does not contain amounts that were uncollectible.

(b) Liquidity Risk

Liquidity risk is the risk that the Corporation will encounter difficulty in meeting obligations associated with its financial liabilities. Liquidity requirements of the Corporation are met through grants from the Ministry. The Corporation manages liquidity risks by its budget processes and

Notes to the Financial Statements

Canadian Energy Centre Ltd.
Year Ended March 31, 2022

Note 5 FINANCIAL RISK MANAGEMENT (Cont'd)

regularly monitoring cash flows to ensure the necessary funds are on hand to fulfill upcoming obligations, including operating expenses.

Note 6 ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	2022	2021
Accounts Payable	$ 163,703	$ 473,643
Accrued liabilities	447,434	472,731
ATB Alberta Rewards Business Card	(6,483)	8,436
Accrued Salaries and Wages	6,000	-
Vacation Payable	43,472	60,869
Balance at end of year	**$ 654,126**	**$ 1,015,679**

Note 7 ACCUMULATED SURPLUS

Accumulated surplus is comprised of the following:

	2022	2021
Balance at beginning of year	$ 974,187	$ 3,035,727
Annual surplus (deficit)	$ 3,543,207	(2,061,540)
Balance at end of year	**$ 4,517,394**	**$ 974,187**

Note 8 SHARE CAPITAL

Share capital is comprised of the following:

	2022	2021
Issued:		
1 Common Share	$ 6,800	$ 6,800
Balance at end of year	**$ 6,800**	**$ 6,800**

Notes to the Financial Statements

Canadian Energy Centre Ltd.
Year Ended March 31, 2022

Note 9 CONTINGENT LIABILITIES

As of March 31, 2022, the Corporation was not named as defendant in any specific legal actions.

Note 10 CONTRACTUAL OBLIGATIONS

Contractual obligations are obligations of the Corporation to others that will become liabilities in the future when the terms of those contracts or agreements are met.

	2022	2021
Obligations under contracts	$ 4,974,141	$ 269,950
Balance at end of year	**$ 4,974,141**	**$ 269,950**

Estimated payment requirement for the next year is as follows:

	Contracts	Total
2022-2023	$ 4,974,141	$ 4,974,141
	$ 4,974,141	**$ 4,974,141**

Note 11 APPROVAL OF FINANCIAL STATEMENTS

The Board approved the financial statements of the Corporation.

Note 12 COMPARATIVE FIGURES

Certain 2021 figures have been reclassified, where necessary, to conform to the 2022 presentation.

Expenses - Detailed by Object

Canadian Energy Centre Ltd.
Year Ended March 31, 2022
Schedule 1

	2022		2021
	Budget	**Actual**	**Actual**
Salaries and Benefits	$ 1,680,000	$ 1,571,200	$ 1,630,505
Office Infrastructure	171,900	77,130	78,225
General and Administrative Expenses	228,500	18,238	9,593
Legal	60,000	137,211	34,050
Accounting	150,000	150,000	150,000
IT	12,000	6,000	6,000
Communications and Marketing	403,692	475,642	1,204,560
Website	50,000	50,180	76,536
Social Advertising	553,000	441,109	294,889
Research	607,750	196,347	127,108
Media	150,000	98,674	-
Freelance – Indigenous	100,000	2,487	-
RFP – Agency of Record	6,000,000	934,359	-
Contingency – Other	159,715	-	123,517
Total Expenses	**$ 10,326,557**	**$ 4,158,577**	**$ 3,734,983**

Salary and Benefits Disclosure

Canadian Energy Centre Ltd.
Year Ended March 31, 2022
Schedule 2

			2022	2021
	Base Salary (1)	Other Cash Benefits (2)	Total	Total
Chief Executive Officer (CEO) (3)	$194,252	$47,114	$241,366	$240,872
Executive Director (4)	171,600	41,678	213,278	212,784
Executive Director (5)	100,320	69,907	170,227	212,784
Executive Director (6)	72,600	17,918	90,518	-
Total Expenses	**$538,772**	**$176,617**	**$715,389**	**$666,440**

The Chair and Members of the Board of Directors receive no remuneration for participation on the Board.

(1) Base salary includes regular salary.
(2) Other cash benefits include compensation in lieu of pension, health benefits and severance. No bonuses were paid during the year.
(3) CEO was hired on October 9, 2019 with an annual base salary of $194,252 and additional 14% and 10% of the annual base salary in lieu of pension and health benefits respectively.
(4) Executive Director was hired on January 27, 2020 with an annual base salary of $171,600 and additional 14% and 10% of the annual base salary in lieu of pension and health benefits respectively.
(5) Executive Director was hired on December 1, 2019 with an annual base salary of $171,600 and additional 14% . and 10% of the annual base salary in lieu of pension and health benefits respectively. Last day of employment was October 31, 2021.
(6) Executive Director was hired on January 8, 2020, and was promoted to current position effective November 1, 2021 with an annual base salary of $171,600 and additional 14% and 10% of the annual base salary in lieu of pension and health benefits respectively.

Related Party Transactions

Canadian Energy Centre Ltd.
Year Ended March 31, 2022
Schedule 3

Related parties are those entities consolidated or accounted for on the modified equity basis in the Government of Alberta's Consolidated Financial Statements. Related parties also include key management personnel and close family members of those individuals in the Corporation.

The Corporation had the following transactions with related parties reported in the Statement of Operations and the Statement of Financial Position at the amount of consideration agreed upon between the related parties:

	2022	2021
Revenues		
Grants	$ 7,701,784	$ 1,673,443
	7,701,784	1,673,443
Expenses		
Rent	57,354	57,354
Insurance coverage	1,501	1,394
	58,855	58,748
Common Share - Department of Energy	$ 6,800	$ 6,800

Other Financial Information

Table of Contents

Lapse/Encumbrance (unaudited)

The following has been prepared pursuant to Section 24(4) of the *Financial Administration Act*.

Department of Energy
Year Ended March 31, 2022

(in thousands)

	Voted Estimate[1]	Supplementary Estimate[2]	Adjusted Voted Estimate	Voted Actuals[3]	Over Expended (Unexpended)
EXPENSE VOTE BY PROGRAM					
Ministry Support Services					
1.1 Minister's Office	$ 995	$ -	$ 995	$ 872	$ (123)
1.2 Associate Minister's Office	572	-	572	544	(28)
1.3 Deputy Minister's Office	667	-	667	608	(59)
1.4 Associate Deputy Minister's Office	552	-	552	523	(29)
1.5 Corporate Services	3,930	-	3,930	2,893	(1,037)
	6,716	-	6,716	5,440	(1,276)
Resource Development and Management					
2.1 Energy Operations	17,389	(1,000)	16,389	14,706	(1,683)
2.2 Energy Policy	34,636	(2,000)	32,636	30,664	(1,972)
2.3 Industry Advocacy	27,000	(10,000)	17,000	8,202	(8,798)
	79,025	(13,000)	66,025	53,572	(12,453)
Cost of Selling Oil					
3 Cost of Selling Oil	72,000	63,000	135,000	233,705	98,705
	72,000	63,000	135,000	233,705	98,705
Climate Change					
4.1 Renewable Electricity Program	8,800	(4,800)	4,000	-	(4,000)
	8,800	(4,800)	4,000	-	(4,000)
Economic Recovery Support					
5.1 Site Rehabilitation Program	452,350	(197,954)	254,396	300,220	45,824
5.2 Mineral Strategy	28,065	-	28,065	28,065	-
	480,415	(197,954)	282,461	328,285	45,824
Utility Consumer Support					
7.1 Electricity Rebate Program	-	300,000	300,000	295,548	(4,452)
	-	300,000	300,000	295,548	(4,452)
CRUDE BY RAIL EXPENSE					
Market Access					
6.1 Crude by Rail	976,000	(51,000)	925,000	866,454	(58,546)
	976,000	(51,000)	925,000	866,454	(58,546)
Total	$ 1,622,956	$ 96,246	$ 1,719,202	$ 1,783,004	$ 63,802
Encumbrance/(Lapse)					$ 63,802
CAPITAL INVESTMENT VOTE BY PROGRAM					
Ministry Support Services	500	-	500	53	(447)
	$ 500	$ -	$ 500	$ 53	$ (447)
Encumbrance/(Lapse)					$ (447)
FINANCIAL TRANSACTIONS VOTE BY PROGRAM					
Climate Change	96,970	-	96,970	96,024	(946)
	$ 96,970	$ -	$ 96,970	$ 96,024	$ (946)
Encumbrance/(Lapse)					$ (946)

(1) As per "Expense Vote by Program" ,"Capital Investment Vote by Program" and "Financial Transaction Vote by Program" page 81 and 82 of the 2021-22 Government Estimates.
(2) Supplementary Supply Estimates approved on March 17, 2022.
(3) Actuals exclude non-voted amounts such as statutory programs, amortization and valuation adjustments.

Annual Report Extracts and Other Statutory Reports

Statutory Report: Public Interest Disclosure Act

Section 32 of the *Public Interest Disclosure (Whistleblower Protection) Act* reads:

32(1) Every chief officer must prepare a report annually on all disclosures that have been made to the designated officer of the department, public entity or office of the Legislature for which the chief officer is responsible.

(2) The report under subsection (1) must include the following information:

(a) the number of disclosures received by the designated officer, the number of disclosures acted on and the number of disclosures not acted on by the designated officer;

(b) the number of investigations commenced by the designated officer as a result of disclosures;

(c) in the case of an investigation that results in a finding of wrongdoing, a description of the wrongdoing and any recommendations made or corrective measures taken in relation to the wrongdoing or the reasons why no corrective measure was taken.

(3) The report under subsection (1) must be included in the annual report of the department, public entity or office of the Legislature if the annual report is made publicly available.

There were no disclosures of wrongdoing filed with my office for your department between April 1, 2021 and March 31, 2022.