GOVERNMENT OF ALBERTA

Energy and Minerals

Annual Report

2023–24

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Note to Readers: Copies of the annual report are available on the Alberta Open Government Portal website https://open.alberta.ca/publications/2818-4033

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Acronyms and Notations

ACTL	Alberta Carbon Trunk Line
ACCIP	Alberta Carbon Capture Incentive Program
AER	Alberta Energy Regulator
AGS	Alberta Geological Survey
AIHA	Alberta Industrial Heartland Association
APIP	Alberta Petrochemicals Incentive Program
APMC	Alberta Petroleum Marketing Commission
ARP	Alberta Natural Gas Reference Price
bbl	Barrel
bbl/d	Barrels Per Day
bcf/d	Billion Cubic Feet Per Day
bpd	Barrels Per Day
CAD$	Canadian Dollar
CCUS	Carbon Capture, Utilization and Storage
CCS	Carbon Capture and Storage
CEC	Canadian Energy Centre
CER	Canada Energy Regulator
CFR	Clean Fuel Regulation
COVID-19	Coronavirus 2019
CO2	Carbon Dioxide
ECCC	Environment and Climate Change Canada
EOR	Enhanced Oil Recovery
EPA	Environment and Protected Areas
EPO	Environmental Protection Order
ESG	Environmental, Social and Governance
FID	Final Investment Decision
FIS	Field Inspection System
GBE	Government Business Enterprise
GDP	Gross Domestic Product
GJ	Gigajoule
GRDA	Geothermal Resource Development Act
ha	Hectare
IH-DIZ	Industrial Heartland Designated Industrial Zone
IRC	Indian Resource Council
IRMS	Integrated Resource Management System
KXL	Keystone XL
LMF	Liability Management Framework
LNG	Liquefied Natural Gas
MMV	Monitoring, Measurement, and Verification
MRDA	Mineral Resources Development Act
MSGC	Metis Settlements General
Mt	Megatonne
NGTL	TC Energy Corporation’s Nova Gas Transmission Ltd.
OAG	Office of the Auditor General
OECD	Organization for Economic Cooperation and Development
OGEC	Oil and Gas Emissions Cap
OPEC	Organization of the Petroleum Exporting Countries
OWA	Orphan Wells Association
PNG	Petroleum and Natural Gas
RFPP	Requests for Full Project Proposals
SLMS	Safety Loss Management System
SMR	Small Modular Reactor
SRP	Site Rehabilitation Program
SRT	Structured Review Tool
Tcf	Trillion Cubic Feet
TIER	Technology Innovation and Emissions Reduction
TMF	Tailings Management Framework for Oil Sands Mining Projects
US$	United States Dollar
WCS	Western Canadian Select
WCSB	Western Canadian Sedimentary Basin
WTI	West Texas Intermediate

Preface

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

The 2023–24 Annual Report reflects the 2023–26 Ministry Business Plans, the Government of Alberta Strategic Plan, as well as the ministry's activities and accomplishments during the 2023–24 fiscal year, which ended on March 31, 2024.

The Annual Report of the Government of Alberta contains Budget 2023 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 and Minerals 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 Petroleum Marketing Commission, the Post-Closure Stewardship Fund, and the Canadian Energy Centre Limited, for which the minister is responsible; and
- other financial information as required by the *Financial Administration Act* and *Sustainable Fiscal Planning and Reporting Act*, as separate reports, to the extent that the ministry has anything to report.

All Ministry Annual Reports 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, 2024, was prepared under my direction in accordance with the *Sustainable Fiscal Planning and Reporting Act* and the government's accounting policies. All the government's policy decisions as at June 6, 2024 with material economic or fiscal implications of which I am aware have been considered in the preparation of this report.

[Original signed by]

Honourable Brian Jean
Minister of Energy and Minerals

Message from the Minister

As Alberta's Minister for Energy and Minerals, I'm pleased to report that the ministry made good progress on numerous strategic initiatives in fiscal year 2023–24.

In June 2023, the ministry was renamed the Ministry of Energy and Minerals. This was deliberate and reflects the ministry's mandate, emerging priorities, and opportunities in today's energy sector. I also encouraged the department to look at opportunities that support our government broadly, and our role as owners of our resources by taking on more ownership direction that aligns with my mandate letter to uphold our energy interests for Albertans. This includes growing the department with skilled staff to take on new challenges since all forms of energy will be needed to meet the broader socio-economic needs of Albertans.

Energy development in Alberta is the key driver of the economy. Directly and indirectly, it is a critical contributor to provincial gross domestic product (GDP), income, employment, and government revenues. Resource royalties generate the largest share of the Alberta government's revenue stream and help fund important programs like health, education, and social services—the things Albertans rely on. In 2023–24, the ministry continued its work to ensure sustained prosperity in the interest of Albertans by promoting responsible development and stewardship of our energy and mineral resources, which includes the collection non-renewable resource revenues. Non-renewable resource revenues totalled around $19.3 billion in the 2023–24 fiscal year, about $0.9 billion higher than the budgeted amount of $18.4 billion, and $6.0 billion lower than the $25.2 billion collected in 2022–23.

Oil and gas will continue to be critical to energy resource development in the decades ahead and a practical bridge toward a decarbonized future. The ministry continued to create the conditions for a diverse energy-mix that includes everything from oil and gas to carbon capture, utilization, and storage (CCUS), and clean hydrogen, with a goal to reach carbon neutrality.

Energy and Minerals has done a tremendous job this past year in building a sound foundation for Alberta to be a global leader in CCUS. We often hear from many other jurisdictions that we are on the right path with our pore-space model, our regulatory framework, and of course the Alberta Carbon Capture Incentive Program, which we announced in November 2023.

Our government recognizes the reality of global energy demands, and we know that transitional fuels, like liquefied natural gas for fuel switching in Asian markets, will be needed in the decades ahead. This past year, we worked with the governments of British Columbia and Canada and cross-ministry partners in the Government of Alberta to address challenges and enable export opportunities for liquefied natural gas and hydrogen-as-ammonia. In November 2023, Energy and Minerals co-hosted a virtual workshop with Environment and Protected Areas on hydrogen and ammonia investment opportunities in Alberta. The virtual workshop was well-received, more than 100 stakeholders having attended from Canada, the U.S., China, Japan, South Korea, Taiwan, India, and Malaysia. Alberta can be at the forefront of global mineral exploration and development because of its wealth of critical minerals resources. As such, the department continued contributing to the Alberta Energy Regulator's Mineral Mapping Program, which involves the surveying, collection, and public release of data and other information to support the exploration, investment, and development of critical minerals in Alberta.

In 2023–24, there was continued interest in the Alberta Petrochemicals Incentive Program (APIP). A significant achievement under APIP is Dow Chemical's final investment decision in November 2023 of almost $9 billion for the Fort Saskatchewan Path2Zero Project. The project is expected to generate approximately 6,000 to 7,000 jobs at peak construction and sustain around 400 to 500 full-time jobs once operational.

As Minister, I am extremely proud of the achievements of the department and our government this past year in support of energy leadership. Albertans own our resources, and we will ensure that we support the growth, optimization, and environmental stewardship for reliable, affordable, and globally leading energy for decades to come. Therefore, I am pleased to present the ministry's annual report for the 2023–24 fiscal year.

[Original signed by]

Honourable Brian Jean
Minister of Energy and Minerals

Management's Responsibility for Reporting

The Ministry of Energy and Minerals includes:

- Department of Energy and Minerals
- Alberta Energy Regulator
- Alberta Petroleum Marketing Commission
- Post-Closure Stewardship Fund
- Canadian Energy Centre Ltd.

The executives of the individual entities above have the primary responsibility and accountability for the respective entities. Collectively, these 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 and Minerals. 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 2023–26 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 2023*.

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 that consider 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 performance;
- safeguard the assets and properties of the province under ministry administration;

- provide Executive Council, the President of Treasury Board and Minister of Finance, and the Minister of Energy and Minerals the information needed to fulfill their responsibilities; and
- facilitate preparation of Ministry Business Plans and annual reports required under the *Sustainable Fiscal Planning and Reporting 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]

Larry Kaumeyer
Deputy Minister of Energy and Minerals

[Original signed by]

Adrian Begley
Chief Executive Officer
Alberta Petroleum Marketing 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.

June 6, 2024

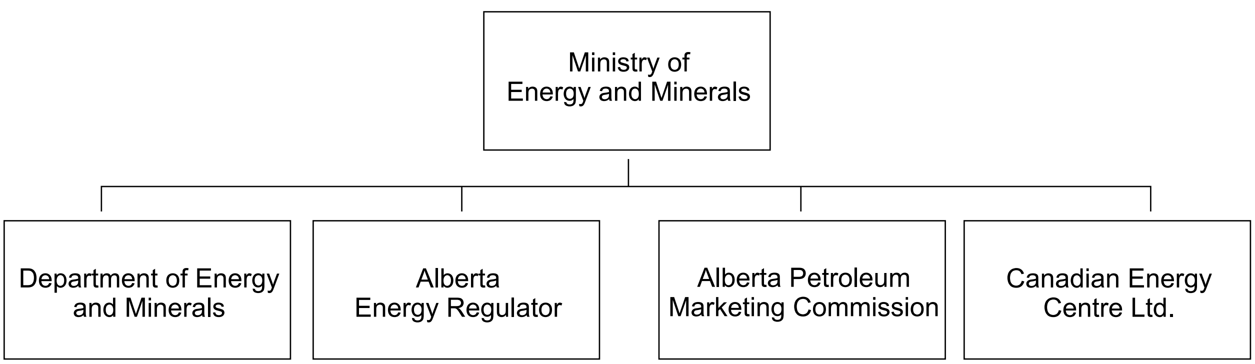
Results Analysis

Ministry Overview

The Ministry of Energy and Minerals manages Alberta's energy and mineral resources to ensure they are developed responsibly and in a way that benefits and brings value to Albertans as the resource owners. Alberta's energy resources include the fourth largest proven oil reserve in the world, abundant natural gas and coal reserves, geothermal heat, pore space and metallic and industrial minerals. The ministry strives to ensure sustained prosperity in the interests of Albertans through the stewardship of energy and mineral resources. This includes having a high regard for the social, economic, and environmental impacts of Alberta's energy development.

The ministry encompasses the Department of Energy and Minerals, the Alberta Energy Regulator (AER), the Alberta Petroleum Marketing Commission (APMC), and the Canadian Energy Centre Ltd. (CEC). The AER and APMC play an important role in overseeing the orderly development of Alberta's energy and mineral resources. A more detailed description of the ministry and its programs and initiatives can be found at www.alberta.ca/energy-and-minerals.

Organizational Structure



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

The outcomes in Energy and Minerals' 2023–26 Business Plan are:

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

Department of Energy and Minerals

- Acts as the owners of Alberta's energy and minerals 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, geothermal, small modular reactors, and petrochemicals.
- Ensures the integration of energy and minerals 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 minerals resources, subject to regulatory approvals.

- Establishes, administers, and monitors the effectiveness of Alberta's royalty systems for Crown-owned energy and minerals resources.
- Collects revenues from the development of Alberta's energy and minerals resources on behalf of Albertans.
- 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, metallic and industrial minerals, geothermal resources, and coal development in accordance with applicable legislation and regulations, within the framework of Alberta's overall energy and minerals policy.
- Responds to changes in the energy and minerals industries while providing regulatory certainty for investors and the public, including assurance that risks are appropriately mitigated throughout the life cycle of energy and minerals projects.
- Provides for the safe, efficient, orderly, and environmentally responsible development of energy and minerals resources.
- Provides public 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 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 and partnership agreements and other commercial contracts.
- Evaluates strategic proposals for adding value to Alberta's resources.

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.

Key Highlights

The Ministry of Energy and Minerals focused on accomplishing two outcomes identified in the 2023–26 Ministry Business Plan:

- 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.

Key highlights and results achieved by the Ministry of Energy and Minerals in 2023–24 include:

- Announced the Alberta Carbon Capture Incentive Program (ACCIP) in November 2023, to support and accelerate the development of new carbon capture, utilization, and storage (CCUS) infrastructure by providing incentives for facilities to incorporate this technology into their operations.
- Approved the Rocky Mountain Clean Fuels Inc. Carseland project for a $20.8 million grant through the Alberta Petrochemicals Incentive Program. The project created 670 jobs during its construction and will use natural gas and gas natural liquids to produce diesel and jet fuel, and hydrogen with CCUS to reduce its emissions.
- Conducted strategic engagements in Canada and abroad to effectively advocate for Alberta's energy sector directly with the federal government and during high-profile events with key global stakeholders and audiences.
- Continued contributing to the Alberta Energy Regulator's (AER) Mineral Mapping Program, which involves surveying, collection and public release of data and other information to support the exploration, investment, and development of critical minerals in Alberta.
- The Closure Nomination Program entered service in April 2023, under the Liability Management Framework. The program enables landowners, land users, and municipal and Indigenous communities to nominate specific inactive sites for cleanup to the AER.
- Led the Government of Alberta's cross-ministry Nuclear and Small Modular Reactor Working Group to share information and collaborate on the development of nuclear and small modular reactors in the province.
- Worked with cross-ministry partners in the Government of Alberta, and the governments of British Columbia and Canada, to address challenges and enable export opportunities for liquefied natural gas and hydrogen-as-ammonia.
- Enabled opportunities in the hydrogen transportation and refuelling sector by conducting targeted discussions with stakeholders, alongside partner ministries. Energy and Minerals also continued to examine the Request for Expression of Interest, which was issued in February 2023, to provide information and help guide the future development of hydrogen transportation in Alberta.
- The *Mineral Resource Development Act* was brought into force with the full proclamation of the act in February 2024, which provides Alberta with a specific resource conservation statute that guides the responsible development of metallic and industrial minerals.
- Established an Alberta-Canada Bilateral Table on Critical Minerals, which fosters collaboration between Alberta and Canada on critical minerals development and focuses on actionable short-term initiatives with tangible outcomes.

- Issued $1 million in combined grants to the Indian Resource Council and the Metis Settlements General Council. The funds will be used to build capacity within communities regarding energy information and analysis, which could encompass items such as net zero initiatives, emerging resources, critical minerals, pipeline closure, potential energy corridors, and Indigenous community information on well sites of interest.

The Ministry of Energy and Minerals remains committed to regulatory approaches and program delivery that reduces unnecessary government oversight and emphasizes outcomes to improve access to government services, attract investment, support innovation and competitiveness, and grow Alberta businesses.

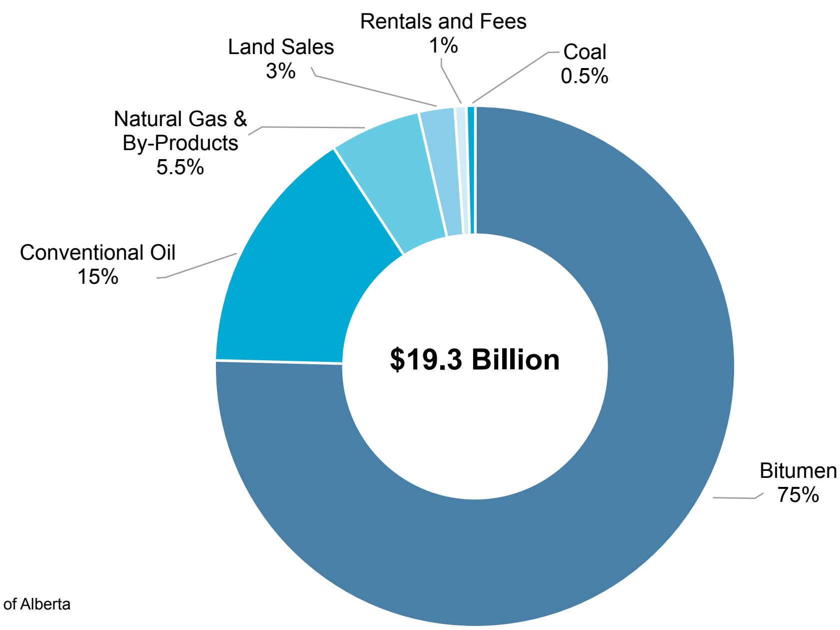
Alberta Energy Resource Sector

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 several other industries, including construction and manufacturing, which benefits communities across Alberta and Canada.

Energy and Minerals 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.

2023–24 Non-Renewable Resource Revenue[1]



Source: Government of Alberta

Non-renewable resource revenues totalled $19.3 billion in the 2023–24 fiscal year, $0.9 billion higher than the budgeted amount of $18.4 billion, and $6.0 billion lower than the $25.2 billion collected in 2022–23. The substantial decrease in 2023–24 non-renewable resource revenue was the result of a much lower West Texas Intermediate oil price and other oil prices that decreased bitumen and conventional oil royalties. Gas royalties have also significantly decreased due to a lower Alberta Natural Gas Reference Price. Lower prices for oil had a downward impact on natural-gas-liquids prices and gas royalties because prices for natural gas liquids tend to follow oil prices.

[1] Note: Totals do not add up due to rounding.

Factors Affecting Non-Renewable Resource Revenue

Multiple factors affect non-renewable resource revenue. The most influential factor affecting non-renewable resource revenue is commodity prices; other factors include global economic conditions, economic growth, demand trends, and supply levels. Other factors, such as capital and operating costs, the U.S. and 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. As part of its analysis to develop price forecasts, the government considers advice from industry consultants, studies the futures market, and analyzes Albertan, North American, and global market trends.

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 rapidly changing, 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	2023–24 Budget	2023–24 Actual
WTI (US$/bbl)	79.00	77.83
Exchange rate	76.20	74.15
Light-Heavy differential (US$/bbl)	19.50	17.29
WCS (US$/bbl)	59.50	60.54
Alberta reference price for natural gas (CAD$/GJ)	4.10	2.07

The table below is produced for the provincial budget. For every unit change, as defined in the table, it displays the estimated impact to the budget. For example, for a dollar drop in price of WTI oil, there would be a $630 million reduction on the provincial budget, or one cent increase in the U.S.-Canadian dollar exchange rate would result in a $490 million reduction on the provincial budget.

Sensitivities to Fiscal Year Assumptions, 2024–25*

(millions of dollars)

	Change	Net Impact
Oil price (WTI US$/bbl)	-$1	-630
Light-heavy oil price differential (US$/bbl)	+$1	-600
Natural gas prices (Cdn$/GJ)	-10c	-10
Exchange Rate (US¢/Cdn$)	+1c	-490
Interest rates	+1%	-229
Primary household income	-1%	-180

* Sensitivities are based on current assumptions of prices and rates, displaying impacts over a 12 month period. They can vary significantly at different price and rate levels. Energy price sensitivities do not include potential impacts of price changes on the land lease sales revenue.

[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

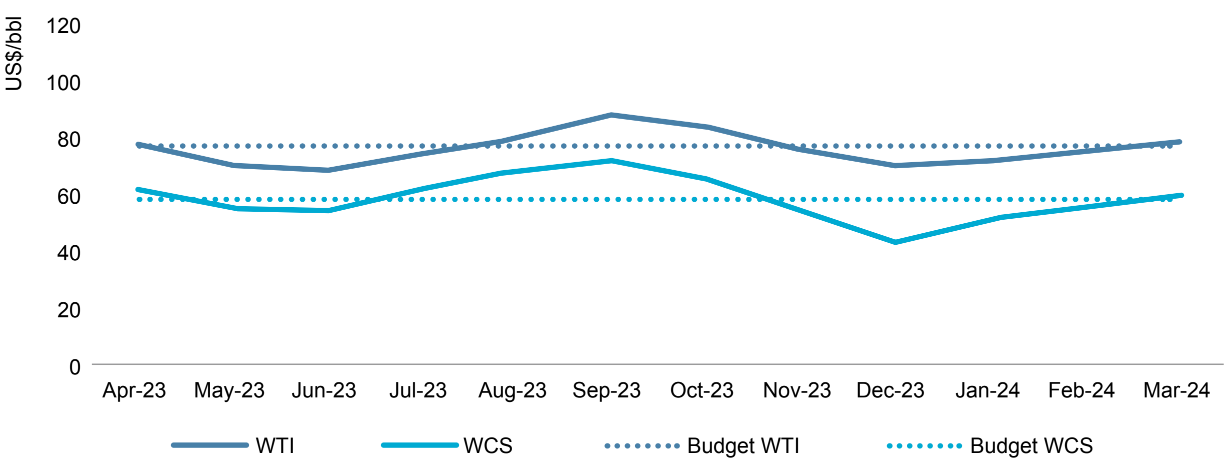
Oil price differences are affected by crude quality (a range from light sweet to heavy sour crudes), location, market demand, and market access for these products. Alberta is landlocked and exports light, medium, and heavy grades of crude oil. Most of Alberta's oil production growth and oil exports are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

At the beginning of 2023, there were expectations of a strong crude oil demand recovery in China after its re-opening from COVID-19 related lock downs. However, China's slower than expected economic growth, persistently high global inflation rates, numerous interest rate hikes by key central banks, and overall global macroeconomic weakness limited crude oil demand growth in 2023–24. In response to the limited crude oil demand, the Organization of the Petroleum Exporting Countries (OPEC) plus, which is made up of other oil-producing countries and individual member countries, announced additional oil production cuts to limit supply in the market and support oil prices. This brought the total supply cut to over 5 million barrels per day since 2022. The additional production cuts were largely offset by increases in non-OPEC oil supply and non-compliance of some OPEC members who produced in excess of their quotas, leaving the oil market over supplied.

Beginning in October 2023, increased geopolitical conflict in the Middle East region created concern in global energy markets and continued to have the market on edge through the end of the fiscal year. There was no significant impact on crude supply from the region during the year, but several attacks on commercial vessels in the Red Sea have prolonged shipping times for crude oil and resulted in increased crude oil prices in early 2024.

West Texas Intermediate (WTI) is the North American price benchmark for light sweet oil and is generally reported as the price at Cushing, Oklahoma. Western Canadian Select (WCS) is a North American price benchmark for heavy crude oil, commonly used to price Canadian heavy oil, and is generally reported as the price at Hardisty, Alberta.

2023–24 Crude Oil Prices



Sources: U.S. Energy Information Administration; Government of Alberta

WTI 2023–24 trend: Budget 2023 was based on an estimate of US$79.00 per barrel price for WTI crude oil and an exchange rate of 76.20 cents U.S. to the Canadian dollar in 2023–24. The actual WTI price averaged US$77.83 per barrel in 2023–24, with an exchange rate of 74.15 cents U.S. to the Canadian dollar. This was due to weak global economic performance, particularly in China, which limited oil demand growth. Central banks in advanced economies raised interest rates as high as required to address high inflation rates, and these increases in interest rates led to slower economic growth and declining crude oil prices in the spring of 2023.

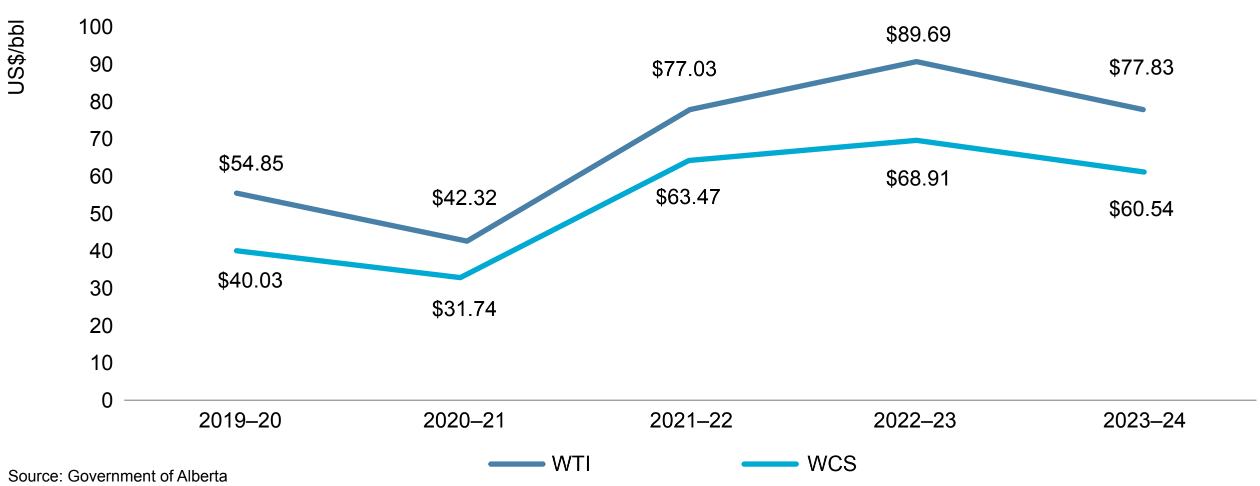
In the summer of 2023, WTI rose after Saudi Arabia and Russia extended voluntary oil production cuts through year-end and as crude oil and distillate inventories declined. In the fall of 2023, WTI declined below US$80 per barrel again as non-OPEC supply increased significantly and as gasoline demand declined seasonally in the United States. WTI remained below US$80 per barrel through much of the winter, before once again surpassing US$80 at the end of the fiscal year, as a result of a gradually tightening supply and demand balance.

WTI five-year trend: The 2023–24 average WTI price of $77.83 per barrel was lower than in 2022–23 but higher than the average WTI price from 2019–20 to 2021–22.

WCS 2023–24 trend: The WCS price was estimated at US$59.50 per barrel for 2023–24 in Budget 2023. The WCS price averaged US$60.54 per barrel in 2023–24, as OPEC+ oil production cuts and increased global heavy oil refining capacity supported demand for Canadian heavy crude oil. WCS climbed to its highest price in September 2023 at US$73.85 per barrel, as global crude oil prices increased due to Saudi Arabia and Russia's extended voluntary oil production cuts. After peaking in September, WCS prices tended downward, reaching the lowest for the year in December 2023 at US$45.48. This was due to heavier than expected seasonal maintenance at refineries in the United States and an increase in Canadian crude oil production in anticipation of the Trans Mountain Expansion Project pipeline start-up. WCS started an upward trend in January 2024 as extreme cold weather across North America led to oil production shut-ins, and visibility on the start-up of the Trans Mountain Expansion Project improved. WCS ended the fiscal year at US$61.28 per barrel.

WCS five-year trend: The WCS price averaged US$60.54 for the fiscal year 2023–24. This is lower than the average price for 2021–22 and 2022–23 fiscal years but higher than the average for 2019–20 and 2020–21 fiscal years.

Crude Oil Prices



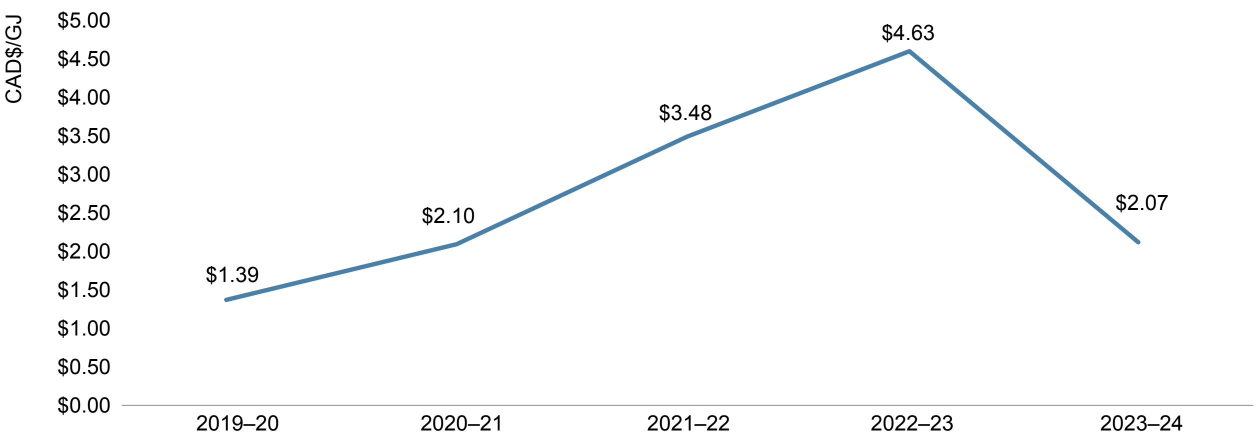
Source: Government of Alberta

The U.S. Midwest and U.S. Gulf Coast are currently the largest markets for Canadian heavy crude oil where Alberta crude oil competes with other Latin American crude oil grades such as Mexico and Venezuela. Historically, a key factor in the price differential between WCS and WTI crude oil grades has been transportation and logistical constraints associated with transporting crude oil out of Western Canada. In the third quarter of 2023, Alberta's crude oil production reached an all-time high as oil producers increased production ahead of the expected the Trans Mountain Expansion Project start-up. However, Trans Mountain Expansion Project construction encountered technical issues, which extended the completion date. With the delay to the startup of the Trans Mountain Expansion Project, crude oil inventories in Alberta increased and the WCS-WTI price differential widened to a high of US$26.64 per barrel in December 2023. In addition, Mexico increased its crude oil exports to the United States in 2023 due to lower domestic refinery utilization, increasing the supply of heavy crude oil in the U.S. Gulf coast and contributing to wider WTI-WCS differentials. With the Trans Mountain Expansion Project started up on May 1, 2024, the WCS-WTI differentials narrowed since the start of 2024. The WTI-WCS differential ended the fiscal year 2023–24 at US$19.13 per barrel in March 2024.

Natural Gas Prices

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

Alberta Gas Reference Prices



Source: Government of Alberta

In general, the supply and demand balance determine natural-gas prices in North America, with some seasonal variation linked to storage levels and weather conditions. Lower storage levels can lead to higher prices to ensure demand is met through the winter season, and higher storage levels can lead to lower prices if supplies are robust and available storage capacity is limited. Lower than normal temperatures in the winter and higher than normal temperatures in the summer can lead to increased natural gas demand and higher prices.

Royalties projected in Budget 2023 were based on an ARP forecast of CAD$4.10/gigajoule (GJ). The realized ARP averaged CAD$2.07/GJ in the 2023–24 fiscal year. The actual natural gas price was well below the budgeted price, on average, due to a combination of mild winter weather across North America, natural gas production increases in both Canada and the U.S. relatively high storage levels in North America, and subdued liquefied natural gas (LNG) export demand.

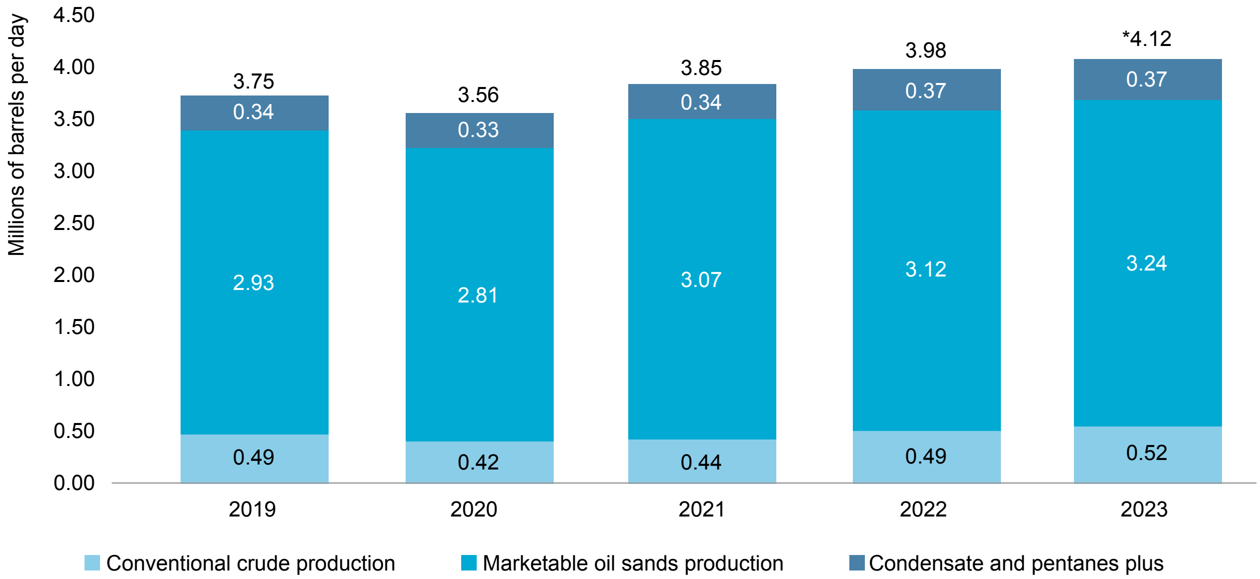
North America is becoming more integrated into global natural gas markets through increasing U.S. LNG exports, which indirectly affects the Western Canadian natural gas market. Increasing LNG export demand from the U.S. allows Canadian natural gas supply to fill emerging supply gaps in the North American market. However, subdued U.S. LNG export demand, resulting from facility maintenance and lower utilization rates, as observed during 2023–24, can temporarily limit Alberta's natural gas exports to the U.S.

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, condensates, and pentanes plus, and marketable oil sands production, which consists of non-upgraded bitumen and upgraded bitumen.

Alberta Crude Oil and Equivalent Production



Source: Alberta Energy Regulator
*Totals may not add up due to rounding.

Marketable oil sands production[4] represents a significant majority of Alberta's crude oil and equivalent production. Over the 2019–2023 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, which significantly affected crude oil demand in Alberta's traditional market, the United States. COVID-19 mitigation measures and safety practices at oil sands facilities were well in place by 2021, which minimized disruptions and helped to increase production. In 2022, marketable oil sands production was 3.12 million barrels per day (bpd), an increase of about two per cent compared to 2021. In 2023, marketable oil sands production reached a record high of 3.24 million bpd, an increase of about four per cent compared to 2022. Marketable oil sands production increased in 2023 as oil sands producers ramped up production in anticipation of the startup for the Trans Mountain Expansion pipeline.

Conventional crude oil production increased from about 0.49 million bpd in 2022 to 0.52 million bpd in 2023. Conventional crude oil production in Alberta remained in the approximate 0.42 million bpd to 0.52 million bpd range during the 2019–2023 period. During this period, production was at its lowest level in 2020 at 0.42 million bpd and at the highest level at 0.52 million bpd in 2023.

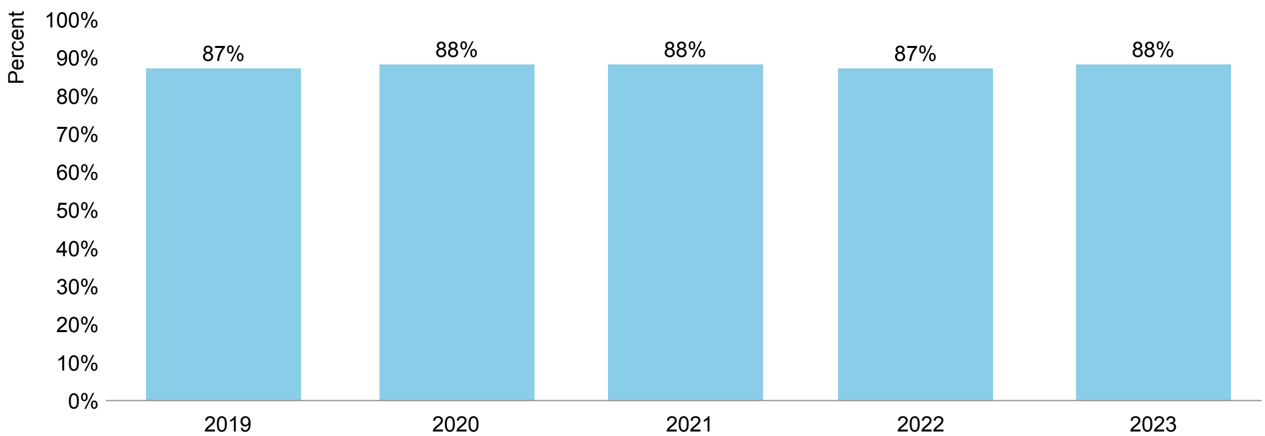
[3] Note: Further information about the sources and methodology for this performance indicator can be found in the Performance Measure and Indicator Methodology section on page 79.

[4] Note: 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.

The total production of condensate and pentanes plus increased by about one per cent from 2022 to 2023 and was at about 0.37 million bpd in both years. During the 2019 to 2023 period, the general decreases in condensate production were counter-balanced by increases in the production of pentanes. In 2023, the total production of condensate and pentanes plus in the province reached an annual-record level, although the record was driven by the pentanes production, with the condensate production declining from the production level in 2022. Condensate and pentanes plus production in 2023 was above the five-year average and supported by more drilling in liquids-rich formations including the Montney and the Duvernay.

Alberta also accounts for a significant majority of Canada's crude oil and equivalent production. According to the Canada Energy Regulator, total Alberta crude oil and equivalent production was estimated to account for about 83.5 per cent of total Canadian production in 2023. This represented an increase from the 2022 share of 82.7 per cent of Canadian production. Over the 2019–2023 period, Alberta's average share of Canadian production was at around 82 per cent, ranging from about 80.4 per cent in 2020 to 83.5 per cent in 2023.

Total Percentage of Crude Oil and Equivalent Leaving Alberta



Source: Alberta Energy Regulator

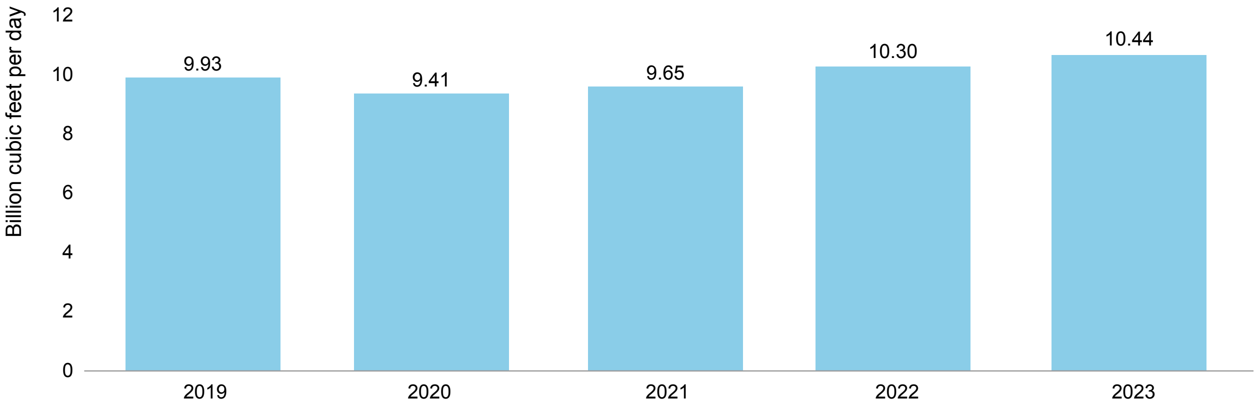
The significant majority of Alberta oil disposition goes to the United States and other Canadian jurisdictions. In 2023, about 88 per cent of Alberta's total crude oil disposition left the province, which is generally in line with the results over the past several years. During the entire 2019–2023 period, the share of crude oil disposition leaving the province was very similar, at about 87 to 88 per cent.

Of the total crude oil disposition leaving the province, the majority has been going to the United States. In 2022, about 79 per cent of total crude oil disposition went to the United States, with about eight per cent going to the rest of Canada, and about 13 per cent being used in Alberta. This breakdown remained very similar in 2023 – about 80 per cent of total oil disposition went to the United States, eight per cent went to the rest of Canada, and 12 per cent stayed in Alberta.

Natural Gas Production

From 2022 to 2023, Alberta's marketable natural gas production rose by about one per cent, with an increase of about 0.14 billion cubic feet per day from 10.30 billion cubic feet per day in 2022 to 10.44 billion cubic feet per day in 2023.

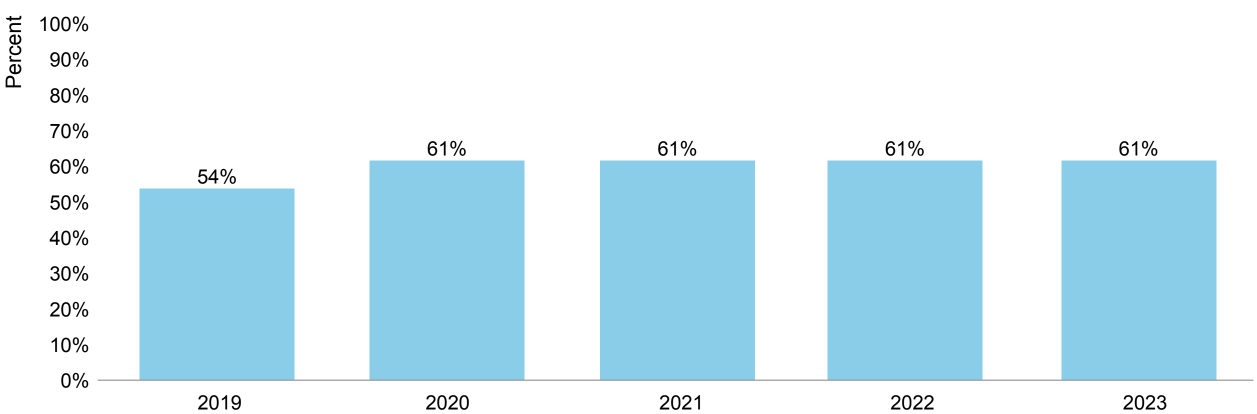
Alberta Marketable Gas Production



Source: Alberta Energy Regulator

In May 2023, Alberta experienced an unprecedented number of wildfires across the province, resulting in the declaration of a state of emergency. Producers safely shut in producing wells and took gas processing plants offline due to large-scale regional evacuations or to focus on the safety of their employees in the regions affected by the wildfires. The wildfires reduced production in the Duvernay, Cardium, Deep Basin, and Montney plays, causing approximately one billion cubic feet per day of natural gas to be shut in for the month of May. Producers began to bring affected facilities back into production through June 2023, with natural gas production returning to pre-wildfire season volumes of approximately 10.6 billion cubic feet per day in July 2023, a rate that was generally maintained for the remainder of the year.

Total Percentage of Gas Leaving Alberta



Source: Alberta Energy Regulator

In 2023, 61 per cent of Alberta's total gas disposition was exported to the rest of Canada (30 per cent) and the United States (31 per cent). In 2023, the share of gas disposition leaving the province was similar to the share in 2022, when also about 61 per cent of Alberta gas left the province.

Alberta accounts for a majority of Canada's marketable natural gas production. In 2023, according to the Canada Energy Regulator, Alberta accounted for about 61 per cent of total Canadian production. While Alberta's production level increased from 2022 to 2023, Alberta's 2023 production represented a decline in the national share of production from 62 per cent in 2022.

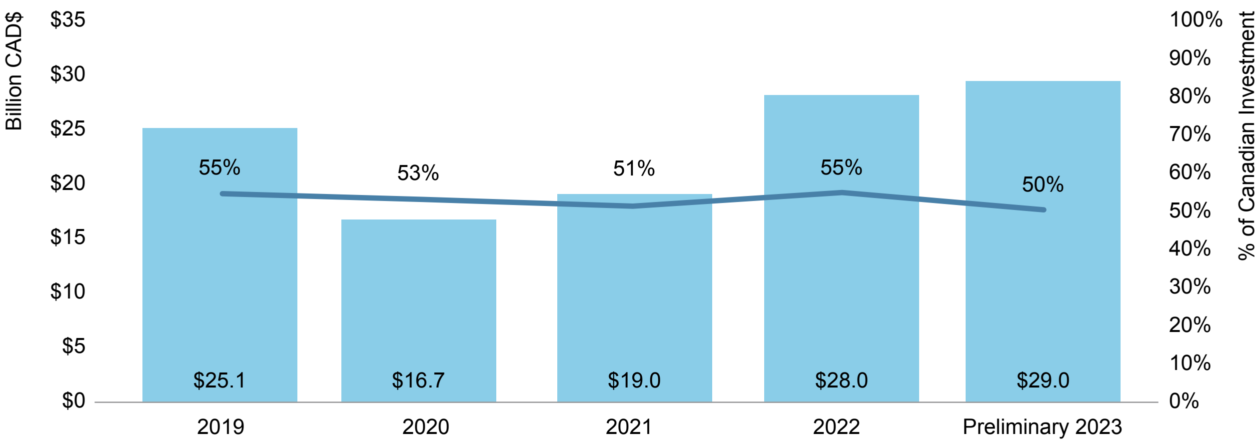
Over the 2019–2023 period, Alberta accounted for more than 60 per cent of Canadian production, ranging from about 61 per cent in 2023 to 64.7 per cent in 2019. Alberta's share of Canadian production was declining every year over the 2019–2023 period, with the share of British Columbia increasing.

Investment: Performance Indicator 1.c[5]

Upstream energy investment in Alberta consists of mining, quarrying, conventional oil and gas investment, oil sands investment, and support activities. Alberta must 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

The COVID-19 pandemic had a major negative impact on investment in the industry compared to the pre-2020 period. The $16.7 billion investment in 2020 in Alberta's mining, quarrying, and oil and gas extraction sector was at the lowest level for the entire 2006–2020 period, 2006 being the first year Statistics Canada reported the capital-expenditure data series. Upstream investment increased to $19.0 billion in 2021.

Total upstream energy industry investment in Alberta for 2022 significantly increased to $28.0 billion, accounting for about 55 per cent of Canadian upstream investment in that year. This result supersedes the preliminary actual result of $24.6 billion, or 53 per cent on the Canadian investment, that was reported in the previous, 2022–23 Annual Report. The increase in upstream industry investment was supported by increasing global energy demand as economies emerged from the COVID-19 pandemic, reflected by higher commodity prices during the year.

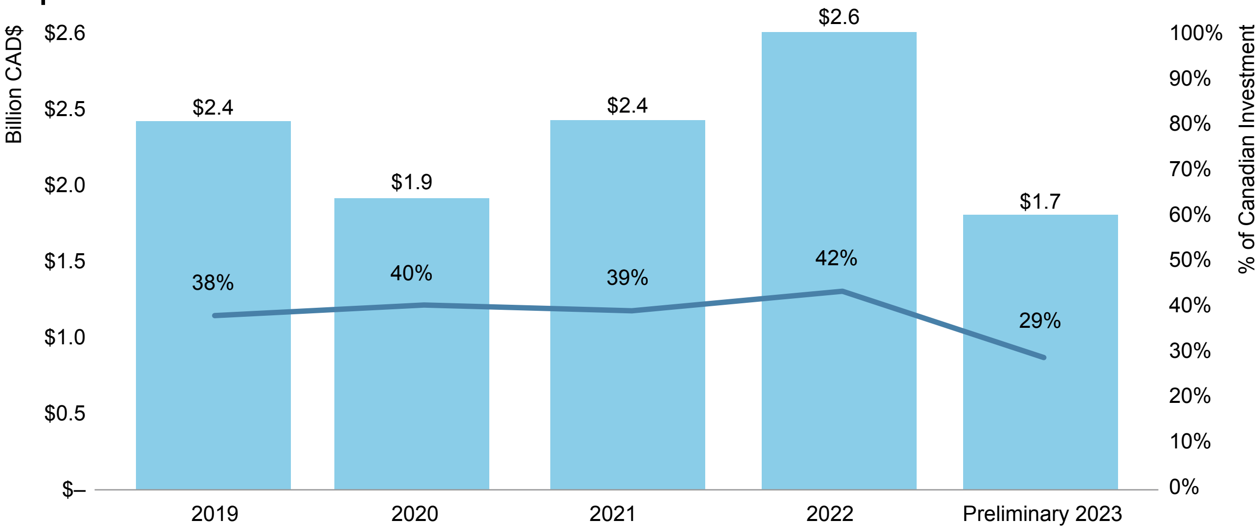
Upstream investment in Alberta was estimated to increase modestly from 2022 as demand for Alberta's energy products remained strong. Total upstream energy industry investment in Alberta was estimated to increase to about $29.0 billion in 2023. While in 2023 Alberta still accounted for significantly more capital investment in the sector than any other individual province, both Saskatchewan and British Columbia had

[5] Note: Further information on sources and methodology for this performance indicator can be found in the Performance Measure and Indicator Methodology on page 79.

higher estimated investment increases in absolute terms from 2022 to 2023. As a result, Alberta's share of the national upstream energy investment has been estimated to decline to just under 50 per cent of the total Canadian investment in this industry in 2023.

It is significantly more difficult to examine the downstream energy industry than the upstream, as the downstream impacts are diffused throughout different industries, which 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 petrochemicals manufacturing activity, among other downstream activities.

Capital Investment in Alberta Downstream Sector



Source: Statistics Canada

The trends observed in Alberta for the upstream energy industry investment do not consistently translate into similar trends for the downstream investment. While the estimated upstream investment in Alberta's upstream energy sector went up from 2022 to 2023, preliminary results for 2023 are estimated at about $1.7 billion, which indicate a decrease of 34 per cent in Alberta downstream investment from the 2022 level of $2.6 billon.

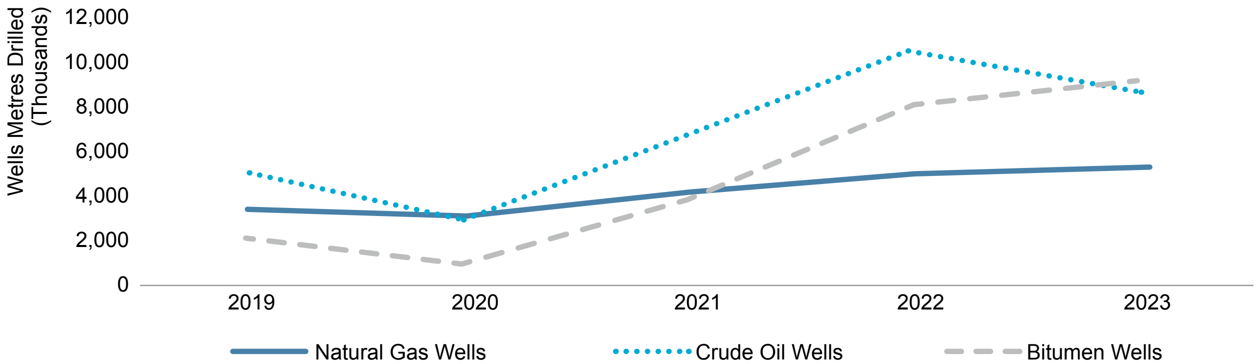
Alberta downstream investment is focused on petroleum and coal product manufacturing and chemical manufacturing, which includes petroleum refining and petrochemical manufacturing activities. The smaller downstream capital investment (relative to upstream investment) is more susceptible to significant year-over-year swings in percentage terms because the timing of major investment decisions that may not reflect long-term industry trends. Alberta has one of the most established petrochemical manufacturing centres in Canada, with potential for growth in new and expanded facilities.

Alberta has a significant 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 is a key part of 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 petrochemicals facilities.

Drilling

The chart below presents drilling activity in Alberta over the 2019–23 period. Wells drilled include both development and exploratory wells. From 2019 to 2020, drilling activity declined for all three types of wells (crude oil, bitumen, and natural gas wells). In 2021 and 2022 drilling activity increased for all types of wells.

Wells Metres Drilled



Source: Alberta Energy Regulator

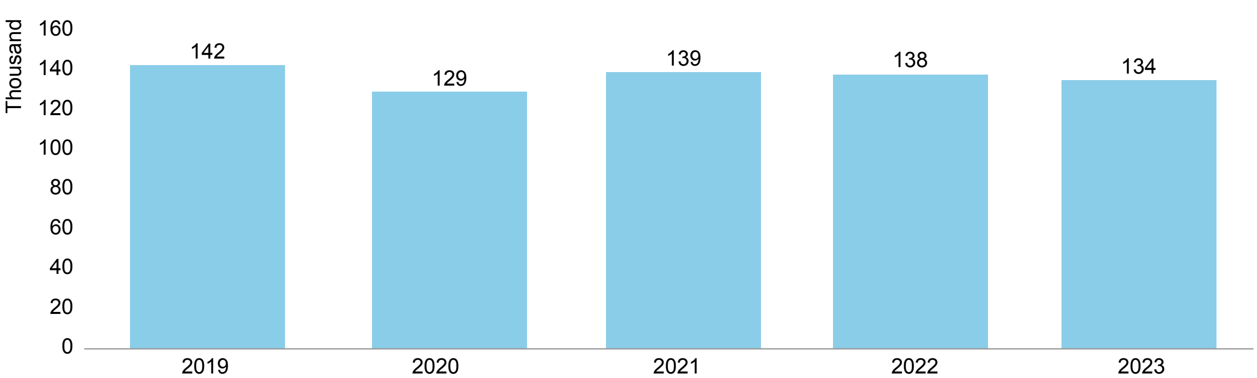
In 2023, drilling activity increased for both natural gas and bitumen wells on a year-over-year basis and decreased for crude oil wells during the same period. The total successful bitumen wells drilled increased by 14 per cent, from 3,580 in 2022 to 4,096 in 2023, while the natural gas wells drilled increased very slightly, by about one per cent, from 956 in 2022 to 969 in 2023. Overall, 2023 witnessed the highest number of bitumen wells drilled since 2014, with 2014 being the first year when the present data series started to be reported. Crude oil wells drilled decreased by 21 per cent, from 3,653 in 2022 to 2,869 in 2023. The decrease in oil wells outweighed the increases in bitumen and gas wells, so the total number of wells drilled in 2023 declined from the 2022 level.

For the 2019–2023 period, 2022 was the strongest year for total metres drilled during the 2019–2023 period. The total metres drilled decreased by two per cent from about 23.5 million metres drilled in 2022 to about 22.9 million metres drilled in 2023.

Employment

Employment in the mining, quarrying, and oil and gas extraction sector has been important to Alberta's economic performance. From 2019 to 2020, employment in the sector decreased from 142,000 people to 129,000 people due to the impacts of the COVID-19 pandemic. In 2023, 134,000 people were employed in this sector – more than during the peak of the COVID-19 pandemic in 2020, but a decrease from 138,000 people employed in 2022 and 139,000 people employed in 2021.

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



Source: Statistics Canada

Discussion and Analysis of Results

Actions that support the priorities of the Government of Alberta Strategic Plan

Key Priority One:
Securing Alberta's Future

Objective 6: Standing up for Alberta's natural resources

Detailed reporting can be found on the following initiatives:

- Site Rehabilitation on page 28
- Market Access on page 29
- Pipelines on page 30
- International Missions on page 32
- Alberta Petrochemicals Incentive Program on page 34
- Hydrogen on page 35
- Plastic Circular Economy on page 38
- Liquefied Natural Gas on page 38
- Minerals Development on page 39
- Helium on page 41
- Lithium on page 41
- Carbon Capture, Utilization and Storage on page 44
- Alberta Carbon Capture Incentive Program (ACCIP) on page 47
- Indigenous Participation on page 51
- Federal Engagement and Provincial Jurisdiction on page 55
- Liability Management Framework on page 58

Outcome One:

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

The ministry develops and manages policies and programs related to the province's royalty system to attract industry investment and to 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 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.

Key Objectives

1.1 Support the competitiveness of Alberta's energy industry by sustainably growing and protecting its energy resource sector, while enabling and accelerating opportunities in emerging resources, including:

- saving Alberta's energy sector money by reducing unnecessary red tape, streamlining and speeding up application processes, ensuring regulatory certainty, and modernizing regulations;
- continuing to invest in environmental stewardship through site rehabilitation;
- advocating and supporting optimization of Alberta oil and gas pipelines, new or under-construction export pipelines, and new liquefied natural gas infrastructure to access new markets, enhance energy security, and grow value-add industries;
- engaging with U.S. and other global partners to firmly establish Alberta as an integral, reliable partner in supporting North American and global energy security;
- continuing to implement the Natural Gas Vision and Strategy, including opportunities in liquefied natural gas, investments in petrochemical manufacturing, creating conditions for deployment of hydrogen across the provincial economy, and development of the plastics circular economy;
- continuing to support and create a competitive regulatory environment that encourages the development of natural gas, hydrogen, liquefied natural gas, helium, lithium, geothermal, and critical minerals; and
- advancing the development of carbon capture, utilization, and storage to support industry in creating lower carbon products that will be more competitive in the global market.

Site Rehabilitation

The Site Rehabilitation Program (SRP) launched on May 1, 2020, providing the opportunity to access up to $1 billion from the Government of Canada's COVID-19 Economic Recovery Plan. It provided relief funding to eligible oil field service workers to perform well, pipeline, and oil and gas site closure and reclamation work. Grant funding was made available in eight funding periods, each with targeted priorities, application criteria, and timelines. The SRP supported economic recovery by increasing employment in the oilfield service sector during the three-year period of the program, while also decreasing the environmental liability associated with oil and gas development. The program's deadline to process applications, complete work, and submit final invoices was extended to May 15, 2022. Any remaining funds left over by the end of the program were to be returned to the Government of Canada.

Over the course of the SRP, approximately $1 billion in grant funding was approved and allocated. A total of $863 million was spent over the program period, with a remaining $137 million unspent. There are several reasons why $137 million in allocated funds were not spent, despite all grant funding being approved and allocated. These were largely beyond the influence of Energy and Minerals, some of which include:

- labour and equipment not being available to grant recipients as oil and gas production increased,
- projects being completed under budget, and
- projects were delayed because of weather and issues with site access.

The spending amount for each funding period in the Energy and Minerals 2022–23 Annual Report remain consistent with the final amount spent, except in Periods 1 and 5, which have been respectively updated to $139.2 million and $327.4 million. The Auditor General's report, released in March 2022, reported that the Government of Alberta had successfully implemented the SRP and specifically highlighted:

- an effective process to award funding,
- accurate and timely reporting,
- monitoring to evaluate performance, and
- meeting responsibilities under the federal-provincial agreement.

Market Access

The Government of Alberta supports proposals for, and the development of, projects that can unlock new markets for Alberta's resources, including the production of oil and gas, new minerals, and other clean energy products. 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 and other provincial jurisdictions to market Canada's responsible and affordable energy.

Forecasts have suggested that Canadian oil production will hit a record high this year, and analysts predict the new pipeline capacity will provide relief for only a couple of years. As such, expanding market access is a top priority for Alberta. Alberta is positioning itself as a reliable energy source to meet the demands of global markets that might otherwise import energy from less environmentally and socially conscious jurisdictions. With the province's abundant crude oil and natural gas reserves, Alberta is uniquely positioned to help Canada, the U.S., and countries around the world ensure safe, secure, sustainable, reliable, and affordable energy supply chains for decades to come. Alberta continues to take steps to support our world-leading energy industry and highlight its critical role in meeting future energy demand while also helping to lower global emissions.

The Government of Alberta continues to promote, on an international stage, the value of the Alberta's energy resources and explore opportunities in hydrogen, liquefied natural gas, greater market access, and other emerging energy resources, such as critical minerals. The Government of Alberta also continues to support projects that secure additional market access for oil and gas producers and help protect the value of Alberta's energy resources.

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;
- continuing to advocate for existing pipelines, including Line 5 and the Trans Mountain Expansion Project;

- participating in intergovernmental forums to build support for Alberta's energy resources; and
- meeting with investors and attending industry events globally to promote Alberta's energy sector.

Pipelines

Keystone XL

An investment agreement was reached in March 2020 between the Alberta Petroleum Marketing Commission (APMC), on behalf of the Government of Alberta, and TC Energy to financially support the construction of the Keystone XL (KXL) pipeline project. Alberta's investment in this project was linked to our province's long-term economic interests, such as higher oil prices, increased ability to ship oil to key markets, and increased volumes of oil sands crude production. The KXL project was estimated to generate at least $30 billion in tax and royalty revenues over 20 years for Alberta taxpayers and was projected to provide jobs for 17,000 Canadians.

An Executive Order signed by President Joe Biden, in January 2021, revoked the Presidential Permit for the cross-border pipeline, resulting in TC Energy suspending activity on the pipeline and initiating a divestment process for KXL assets. An agreement was reached to provide APMC proceeds from disposition of certain KXL assets.

In February 2022, the Government of Alberta, through the APMC, filed a notice of intent to initiate a legacy North American Free Trade Agreement claim under the Canada-United States-Mexico Agreement over the cancellation of the presidential permit for the KXLpipeline border crossing. The claim will seek to recover no less than $1.3 billion of the government's investment.

In April 2023, a Notice of Arbitration was filed to formally begin the arbitration process, which resulted in the constitution of a three-person tribunal in July 2023. The first hearing of the tribunal to settle initial procedural matters, including the schedule for the arbitration, occurred in November 2023. Based on the approved schedule, the APMC filed its main pleading in arbitration on April 16, 2024. During the fiscal year that ended March 31, 2024, $8.9 million was received from the liquidation of the KXL project assets, bringing cumulative liquidation proceeds to $110.5 million.

Trans Mountain Expansion Project

The Trans Mountain Expansion Project is the twinning of an existing 1,150 kilometres pipeline between Strathcona County, Alberta, and Burnaby, British Columbia that provides Alberta with the ability to diversify its crude oil exports, mainly by providing access to tidewater. The Trans Mountain Expansion Project is projected to add 590,000 barrels per day (bpd) from Western Canada, with plans to serve U.S. and Asia-Pacific markets starting in the second quarter of 2024. This development is expected to fuel a surge in Canadian oil exports to the U.S. Pacific Coast region, potentially displacing imports from Latin America and the Middle East. Furthermore, the Trans Mountain Expansion Project is poised to facilitate direct access to China and other Asian markets that have a demand for heavy oil, but limited access to Alberta crudes.

Energy experts expect that the completion of the pipeline will stabilize prices in the Western Canadian crude market for the next 18 to 24 months, alleviating logistical bottlenecks and reducing price discounts. This stabilization may enhance the competitiveness of Western Canadian Select compared to West Texas Intermediate, driving a positive shift in pricing dynamics. With the Trans Mountain projected to come online by May 1, 2024, Alberta's total pipeline export capacity will increase to about 5.17 million bpd.

The project has revised its cost estimate of $34 billion, representing a 10 per cent increase over the previous estimate of $30.9 billion. This was mainly due to construction pressures and the allowance for funds used during construction. The revised estimate of $34 billion is contingent on the receipt of final costs and expenses upon the completion of the project, with a final cost estimate expected about three months after construction concludes. In November 2023, the Canada Energy Regulator (CER) approved a preliminary interim benchmark toll of $11.46 per barrel from Edmonton to Burnaby for the expanded system. The interim benchmark tolls will take effect when the expansion project is operational in May 2024. A CER hearing to set final interim tolls for the expanded system is under way but the reasonableness of the cost increases and the resulting high tolls are disputed by committed shippers who have signed long-term contracts with Trans Mountain.

Despite the increased capacity from Trans Mountain Expansion Project, challenges such as pipeline congestion and surging production are expected to persist. Canadian oil producers anticipate a significant reduction in the light-heavy price discount once the pipeline becomes operational. However, this relief could be short-lived, as pipeline capacity may reach full utilization again in a few years, necessitating ongoing infrastructure developments to keep pace with production growth.

In 2023, Trans Mountain supported 125 organizations and local community initiatives, contributing more than $290,000 in financial assistance and in-kind contribution. It has also made ongoing efforts to engage Indigenous businesses, with 25 per cent of contracts awarded to Indigenous firms, employing more than 3,000 Indigenous workers. The project has achieved a significant milestone, including regulatory approvals for required amendments, such as the successful completion of the pipe pullback for the Mountain 3 Horizontal Directional Drill in the Fraser Valley between Hope and Chilliwack, British Columbia. Mechanical completion of the pipeline is expected by early 2024, with product flowing by the second quarter of 2024.

Enbridge Line 5

Energy and Minerals continued to support and advocate for Enbridge in legal cases against Line 5, which is a vital component to the Enbridge Mainline system. The precedent of a safely operated, fully regulated pipeline being pulled out of service would lead to a serious disruption of the energy market and has broad implications for existing and future energy projects.

In alignment with Enbridge's objectives and to support the continued operation of Line 5, the Government of Alberta has maintained its advocacy efforts as part of a coordinated "team Canada" approach:

- The Government of Alberta supported Canada's amicus brief, submitted September 18, 2023, to the federal court in support of Enbridge's legal position in Wisconsin.
- The Government of Alberta continued to support Canada's bilateral negotiations with the United States under Article IX of the 1977 Transit Pipelines Treaty, in both Michigan and Wisconsin.
- In February 2024, the Government of Alberta, with the support of the governments from Saskatchewan, Ontario, and Quebec, sent a joint letter to David Cohen, U.S. Ambassador to Canada, advocating for the continued operation of Line 5 within the principles of the 1977 Transit Pipelines Treaty.

Line 5 is crucial 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 broader Great Lakes Region. It also provides reliable energy jobs and economic benefits on both sides of the border.

Enbridge Mainline

On March 4, 2024, the Canadian Energy Regulator (CER) approved Enbridge's Mainline Tolling Settlement and Final Toll Application, as filed on December 15, 2023, for tolls from July 2021 to December 2028. The settlement was a result of negotiations between Enbridge and the Representative Stakeholder Group, which unanimously supported the agreement. The Government of Alberta supported the timely approval of the settlement agreement. The CER noted the significant weight it gave to the unanimous stakeholder support upon issuing its approval, as well as the absence of any opposition.

The settlement agreement provides Enbridge cost recovery certainty on Line 5 capital expenditures to ensure this critical piece of infrastructure remains operational.

Natural Gas Market Access

Alberta plans to grow the petrochemicals sector, which is predominantly located in the Industrial Heartland Designated Industrial Zone (IH-DIZ). Access to adequate and low-cost feedstock remains one of the most critical components for the continuous growth and functioning of the petrochemical sector, which is necessary for petrochemicals producers before a Final Investment Decision (FID) can be made. However, the current process only makes consistent gas available after FID. This regulatory approval, and timeline misalignment between industrial demand and natural gas delivery poses significant challenges on industrial growth and demand within the IH-DIZ.

Energy and Minerals is working with Environment and Protected Areas, Alberta Industrial Heartland Association (AIHA), and various Industrial stakeholders to identify barriers and opportunities for a reliable supply of natural gas into the IH-DIZ. The study included a stakeholder workshop in September 2023 that was hosted by Environment and Protected Areas, Energy and Minerals and co-hosted by AIHA. A draft report was submitted based on the outcomes of the workshop and the study is expected to conclude in April 2024. Recommendations from the study, if implemented, may promote investment attraction, support job creation and economic development.

TC Energy Corporation Nova Gas Transmission Ltd.

TC Energy Corporation Nova Gas Transmission Ltd. (NGTL) continues to add capacity to its natural gas gathering and transportation system, located throughout Alberta and northeastern British Columbia, to meet growing system supply and demand. Around 2 billion cubic feet per day of throughput capacity was added to the system between quarter one of 2022 and quarter four of 2023. Between 2024 and 2026, another 1 billion cubic feet per day of capacity and market access is intended to be added.

The Canadian Energy Regulator (CER) approved NGTL's Willow Valley Interconnect Project in May 2023, which provides a new connection point for delivery of Canadian natural gas to the Coastal Gas Link pipeline and access for Western Canadian Sedimentary Basin (WCSB) supply to the global liquefied natural gas (LNG) markets. The Coastal Gas Link pipeline has the capacity of 2.1 billion cubic feet per day.

In September 2023, the CER also approved Firm Transportation-Linked Export Service, which is a tolling service designed to facilitate LNG market access for WCSB gas connected to the NGTL system. The service permits NGTL to set an array of LNG export tolls on its 15,000-mile system that reflect regional depreciation, return, pipe integrity, taxes, operations, and maintenance costs, and was unanimously supported by shippers across its network.

International Missions

The Government of Alberta actively supports and promotes initiatives aimed at expanding market access for Alberta's resources, encompassing oil and gas as well as emerging mineral production. Recognizing the enduring significance of oil and gas in global energy demand projections, the government remains steadfast in its advocacy for Albertans and Canadians whose livelihoods hinge on this sector. Collaboration with federal counterparts underscores a commitment to showcasing Canada's responsible and cost-effective energy portfolio on the international stage.

Recent geopolitical developments and associated energy price spikes have underscored the importance of bolstering continental and global energy security. Alberta's vast reserves of crude oil and natural gas uniquely position it to contribute substantially to diversifying supply chains away from politically unstable sources. By prioritizing safe, reliable, and affordable energy pathways, Alberta aims to be a dependable alternative for regions currently reliant on less sustainable energy sources.

In 2023–24, the Minister of Energy and Minerals conducted strategic engagements with three jurisdictions—Canada, the United States, the United Arab Emirates, and Europe—to effectively advocate for Alberta's energy sector during high-profile events with key global stakeholders and audiences. The engagements were based on strategic priorities of Alberta's energy sector. Some highlights include:

- **Energy and Mines Ministers' Conference (EMMC), August 30–September 1, 2023, Québec City, Quebec:** The Minister met with federal, provincial, and territorial energy and mines ministers to promote energy security and increase the competitiveness of Canadian energy and mining sectors. Discussions focused on strategies to support decarbonization and enhance regulatory efficiency.
- **World Petroleum Congress, September 17–21, 2023, Calgary, Alberta:** The Minister shared Alberta's expertise on responsible energy development and promoted Alberta as the owner of its natural resources and a key part of the solution to global supply. The mission also increased Alberta's international profile as a natural gas investment destination, and highlighted ways in which Alberta can contribute towards global decarbonization and energy security in international media.
- **Conference of the Parties to the United Nations Framework Convention on Climate Change 28, November 30, 2023, United Arab Emirates:** A ministry official attended the convention as a part of the provincial delegation.
- **Prospectors and Developers Association of Canada Convention, March 3–5, 2024, Toronto, Ontario:** The Minister promoted Alberta's critical-minerals strategy and highlighted Alberta's investment and collaborative supply chain opportunities to national and international stakeholders.
- **CERAWeek, March 18–22, 2024, Houston, Texas:** The Minister highlighted Alberta's investment potential and the province's role as a resource owner uniquely positioned to enhance global and North American energy security through its ability to satisfy current and future energy demand for affordable, reliable, and responsible energy sources, while at the same time playing a crucial role in lowering global emissions. The event provided a forum for Premier and Minister to share Alberta's responsible approach to resource development and its leadership in decarbonizing oil and gas production, hydrogen, CCUS, and work with provincial, territorial, and international counterparts to influence energy policy development.

Participation at these events achieved the following objectives:

- Emphasized Alberta's position as the owner of its natural resources and showcased Alberta's leadership in global emissions reduction.
- Established Alberta's integral role in North American and global energy security by maintaining and expanding collaborative stakeholder relationships.
- Encouraged the use of Alberta's responsibly produced energy products and minerals.
- Highlighted Alberta's investment potential across the energy value chain.

The total cost for out-of-province travel for the official delegations in 2023–24 was approximately $151,000. This includes all travel and hosting costs for the delegations during out-of-province engagements.

Natural Gas and Hydrogen Investment Attraction

In April 2023, Energy and Minerals led the Government of Alberta's participation in the second annual Canadian Hydrogen Convention in Edmonton, Alberta. The event provided a strategic platform for Alberta to engage hydrogen policymakers, businesses, and investors on Alberta's natural gas value chain development, hydrogen investment opportunities, and international and domestic deployment pathways. During the 2023 Canadian Hydrogen Convention, Energy and Minerals achieved the following outcomes by attending the convention:

- positioned Alberta as a leader in clean hydrogen production with a regulatory framework that supports carbon capture, utilization and storage,
- showcased Alberta's clean hydrogen investment opportunity and advocate for greater federal incentives by holding bi-lateral meetings with key stakeholders, and
- showed support for major announcements by Edmonton Global aimed at increasing clean hydrogen vehicle use within the Edmonton Region.

In November 2023, Energy and Minerals co-hosted a virtual workshop with Environment and Protected Areas on hydrogen and ammonia investment opportunities in Alberta. The virtual workshop was well-received with over 100 stakeholders in attendance from Canada, the U.S., China, Japan, South Korea Taiwan, India, and Malaysia.

Alberta Petrochemicals Incentive Program

Launched in October 2020, Alberta Petrochemicals Incentive Program (APIP) is a pillar of the Natural Gas Vision and Strategy and will further diversify Alberta's energy sector. The program objective is to make Alberta a top global producer of petrochemicals. APIP is a grant-based program created to attract petrochemicals investments in Alberta, increase investment, and create jobs. It provides grants worth 12 per cent of a project's eligible capital costs to attract investment in new or expanded petrochemicals facilities. The program application process consists of two stages: Advance Notification (the initial review) and Qualification (final review). Projects that are successful in both stages enter into a grant agreement with specific project milestones that allow the grants to be paid out after the projects become operational. Petrochemicals facilities that use natural gas, natural gas liquids, or petrochemicals intermediates in the manufacturing of its own products are eligible for APIP.

In November 2023, following feedback from industry, Energy and Minerals made some changes to the way that APIP funding was administered for capital projects valued above $150 million. The changes allow greater flexibility in first-year program funding, providing more financial stability during the initial stages of the project. Potential investors are expected to find this increased financial flexibility attractive. These amendments will not increase the cost of the program to Albertans.

Energy and Minerals evaluates the program's performance by tracking investment, jobs created, economic impact, and environmental benefits. Performance assessment includes monitoring project completion timelines, soliciting stakeholder feedback, and analysing program utilization. Comparative analysis with similar programs elsewhere helps identify improvements. This multifaceted approach ensures APIP effectively supports the petrochemicals sector's growth, sustainability, and competitiveness in Alberta. Using internal data such as investment attraction highlights trends and areas for improvement, while external benchmarks allow for gauging competitiveness and effectiveness. Combining both provides a comprehensive view of performance, identifying strengths and opportunities for enhancement.

Since its inception, the program received a total of 23 applications. Energy and Minerals approved eight advance notifications and one qualification application. Four applications have been withdrawn, cancelled, or rejected.

In 2023–24, there was continued interest in the program, and one project received qualification approval with grant agreement negotiations under way. The Rocky Mountain Clean Fuels Inc. Carseland project is a $173-million gas-to-liquid facility that was approved in April 2023. The Carseland project was approved for a grant of $20.8 million. The facility will use natural gas and natural gas liquids as feedstock, resulting in cleaner fuels used to produce diesel and jet fuel, and hydrogen with carbon capture utilization and storage to reduce emissions. The project created 670 jobs during construction, which includes direct, indirect, and induced jobs, and is expected to add 15 full-time jobs in operations. The project is currently under commissioning.

A significant achievement under APIP is Dow Chemical's final investment decision in November 2023, of almost $9 billion for the Fort Saskatchewan Path2Zero Project, which was announced in November 2023 and includes a further $2.5 billion expected from project partners. The project is expected to generate approximately 6,000 to 7,000 jobs at peak construction and sustain around 400 to 500 full-time jobs once operational. The project has completed the advance notification stage and is undergoing the final qualification review.

Previous approvals under the program include the Inter Pipeline Heartland Petrochemical Complex, Air Products' Hydrogen Production and Liquefaction Facility, and Dow Chemicals' Fort Saskatchewan Furnace Expansion. In 2023–24, grant payments were made to Dow Chemicals and Inter Pipeline. The Dow Chemicals Furnace Improvement project was awarded a total of $21.7 million in grants for fiscal years 2022–23 and 2023–24. The disbursement of the first grant occurred in June 2023, and the second grant was paid in January 2024. The Inter Pipeline Heartland Petrochemical Complex facility received its first grant payment of $98.6 million. Further reporting on these projects can be found in previous annual reports.

Albertans have benefited from APIP through increased job creation in the petrochemicals sector, stimulation of local economies by attracting significant investments, and advancement towards a more diversified and sustainable energy industry. Additionally, the program has contributed to environmental sustainability efforts by supporting projects that incorporate carbon capture and low-carbon technologies. Companies that have submitted applications so far represent almost $39 billion in total potential investment, over 60,000 potential construction jobs, and more than 2,400 permanent jobs.

Hydrogen

Hydrogen is a clean fuel that only produces water and heat when combusted. It can be used for heating, power generation and storage, transportation, and industrial processes. Alberta's abundant natural gas resources, favourable geology for carbon capture, and experience producing hydrogen present a unique opportunity for the province to be an early adopter of clean hydrogen and position itself as a global supplier to facilitate clean-energy transition.

Following the announcement of the Hydrogen Roadmap in 2021, Energy and Minerals started working on developing policy and legislative amendments to enable these key growth markets, which is currently ongoing.

Hydrogen Transportation and Refuelling

Advancing hydrogen transportation creates demand for hydrogen while also reducing emissions across sectors that face greater challenges to reduce emissions, such as the heavy-duty transportation. Hydrogen transportation is gaining momentum in the medium-and-heavy-duty sector (buses, class 8 trucks, and potentially freight rail).

Energy and Minerals has continued to examine results from the Request for Expressions of Interest that was issued in February 2023, which provided information about the future of the hydrogen transportation market and will guide future steps regarding the conditions that need to be in place for industry to design, build, operate, and own hydrogen fueling stations. Targeted discussions with stakeholders continued during the 2023–24 fiscal year, alongside partnering with other ministries (Technology and Economic Corridors, Service Alberta and Red Tape Reduction, and Municipal Affairs) also supporting the growth of hydrogen transportation. Construction of Air Products' Hydrogen Production and Liquefaction Facility also began during 2023–24. The project is a recipient of Alberta Petrochemicals Incentive Program grants and represents the first major natural gas and carbon capture, utilization and storage hydrogen project in Canada. Air Products announced the first liquid hydrogen refueling station, to be built alongside their hydrogen production facility. The company announced plans to supply other hydrogen fueling stations using liquid hydrogen refueling trucks. Air Products has also stationed a mobile hydrogen refueler at the airport to provide hydrogen for the fleet of Toyota Mirai hydrogen fuel cell vehicles. The airport will begin with a fleet of five hydrogen fuel cell vehicles to be used by employees and plans to expand the fleet to as many as 100 cars to serve as a taxi service at the airport.

Clean Hydrogen Centre of Excellence

The Clean Hydrogen Centre of Excellence was approved by the government in February 2022 with a commitment of $50 million over four years by the Government of Alberta. The purpose of the Centre, which is operated by Alberta Innovates, is to close innovation technology and support gaps where federal and provincial funding does not exist and support innovation across the entire hydrogen supply chain.

Alberta's Hydrogen Roadmap was released on November 5, 2021, and commits to establishing a Hydrogen Centre of Excellence to activate technology and innovation, lead the way, and build alliances as one of the first near-term policy actions.

In 2022–23, the Clean Hydrogen Centre of Excellence provided over $20.1 million to 18 projects to advance innovations in hydrogen through its first funding competition. The centre's second funding competition was initiated in October 2023, in partnership with Natural Resources Canada. The Clean Hydrogen Centre of Excellence received 95 proposed projects, which was a 40 per cent increase from the first competition. The proposed projects were valued at $365 million and requested $104 million in support. Following Alberta Innovates' screening and evaluation process, 21 proposals were recommended for funding, which would provide $24.6 million in support from the Clean Hydrogen Centre of Excellence.

The Clean Hydrogen Centre of Excellence also launched its continuous intake program, which provides ongoing funding to projects. Projects selected for funding are reviewed on their merit and awarded funding. This continuous intake program provides a total of $3.8 million to projects until 2026. Projects funded under the continuous intake program aim to address the development of opportunity analysis, studies, and supporting codes and standards development.

In 2023, the Clean Hydrogen Centre of Excellence initiated a hydrogen public awareness campaign in collaboration with third-party consultants and stakeholders. The campaign is currently being implemented.

Ammonia

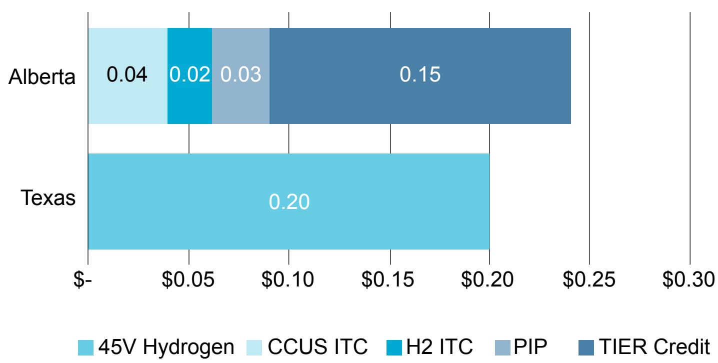
The Alberta Hydrogen Roadmap outlines hydrogen exports as one of the five leading markets for hydrogen end-use opportunities. In support of broader energy transition, a substantial upsurge in clean ammonia transportation and trade is anticipated.

Ammonia is considered an efficient energy carrier for hydrogen, which can also be used directly for power generation or as marine fuel to lower carbon emissions. Interest in clean ammonia is growing, especially in Japan and South Korea, which have plans to use ammonia directly for electricity. Alberta has the opportunity to export large volumes of low-cost, clean ammonia, supporting the decarbonization efforts of allies and supporting their energy security.

Energy and Minerals is currently working with partner ministries such as Jobs, Economy and Trade, Transportation and Economic Corridors, Indigenous Relations, Municipal Affairs and Environment and Protected Areas, the federal government, and the Government of British Columbia to address critical challenges and enable hydrogen-as-ammonia export opportunity that will support the growth of the industry for decades to come. Key to this opportunity is the development of an economic transportation corridor stretching across Canada and reaching tidewater. This will enable the safe movement of ammonia alongside a number of other export opportunities, establishing market connections that will serve Alberta's larger economy for decades to come. Rail represents the most immediate opportunity, where existing rail infrastructure and port facilities can be leveraged to move ammonia to market.

Blue Ammonia is Competitive

Average Annual Gross Revenue from policy sources for hypothetical one-million tonne/year blue-ammonia project 2025–2034
($ per kg of ammonia)



Did you know?

Research conducted by two Canadian research organizations, The Transition Accelerator and Clean Prosperity, shows that Canada's federal Investment Tax Credits (ITC) for carbon capture, utilization and storage carbon capture, utilization and storage (CCUS) and hydrogen when combined with the province's Alberta Petrochemicals Incentive Program (APIP) and Technology Innovation and Emissions Reduction (TIER) credits can create a superior source of revenue when compared to the *US Inflation Reduction Act*.

Early analysis indicates that capital investment in the ammonia export industry could be worth billions of dollars over the next several years, with significant job creation. If potential projects reach Final Investment Decision, it is expected that programs like the Alberta Petrochemicals Incentive Program will be leveraged, supporting that program's initial guide to help grow and diversify the province's natural gas sector.

Energy and Minerals worked closely with the Japan Organization for Metals and Energy Security on a cost competitiveness study, comparing Alberta with other potential clean ammonia producers around the world. The study was completed in June 2023, and results indicated that Alberta is largely cost-competitive due to our low-cost natural gas feedstock, with supportive policies having a strong potential to further reduce the cost of Alberta-made clean ammonia. Energy and Minerals also conducted an analysis of the carbon intensity associated with Alberta-based clean ammonia production, comparing against similar competing jurisdictions around the world. Alberta's results were largely competitive with other regions, despite having longer inland transportation times and distances.

Energy and Minerals consulted with industry to gain a strong understanding of critical challenges, timelines for necessary enablers, and what actions are necessary in the short and medium term. Energy and Minerals used the results to inform the establishment a bi-lateral working relationship with Transport Canada and Natural Resources Canada to advance federal discussions on the development of export corridors and establishing the ammonia export opportunity. From these discussions, preliminary economic modelling has also been performed to assess the potential benefits for the province from the types of investments being planned for Alberta's ammonia export sector.

All potential ammonia-for-export producers are currently looking to move ammonia by rail to export facilities on the west coast of Canada. As rail lines between provinces are federally regulated, Transport Canada is taking the lead on addressing safety, risk, and liability concerns. Alberta is offering support and collaborating closely with the federal government to ensure ammonia can move safely by rail to tidewater.

Plastic Circular Economy

The Plastics Circular Economy is one of five pathways identified in Alberta's Natural Gas Vision and Strategy that has great potential for growth. The Government of Alberta is working to establish recycled plastics as a valued petrochemicals commodity to meet growing global demand, build a reputation as a responsible producer of plastics, and keep plastics out of the natural environment. The ambition is to establish Alberta as the western North American centre of excellence for plastics diversion and recycling by 2030. This includes accelerating research and technology innovation required to unlock advanced chemicals recycling so it can be incorporated into the manufacturing process and developing province-wide plastics recycling and diversion systems.

Canada's federal plastic initiatives have significant implications for Alberta's petrochemicals industry, plastic manufacturing sector and future investment in Alberta's economy. These include:

- Plastic manufactured items were labelled "toxic" labelling under the *Canadian Environment Protection Act*. Alberta is intervening in Canada's recent appeal of the Federal Court's ruling on November 16, 2023, determining that the toxic designation of plastics was unreasonable and unconstitutional. The result has implications to the federal government's plastic initiatives, as it is the foundation for subsequent regulations on plastics, such as the Single-use Plastics Prohibition Regulations.
- Environment and Climate Change Canada, on behalf of Canada, is negotiating a global treaty on plastics pollution that has the potential to restrict plastic production or plastics (e.g. via a ban or resin cap). Limits or bans on resin production and plastic products would have significant implications for Alberta's petrochemical industry, such as reduced employment in the sector, restricted trade, and capped innovation. Energy and Minerals and Environment and Protected Areas continues to advocate for Alberta's interests to the federal government on plastic waste management issues.

Liquefied Natural Gas

Advancing the liquefied natural gas (LNG) industry is a key goal of Alberta's Natural Gas Vision and Strategy, which targets Alberta's natural gas to have access to Asian and European markets through two to three additional mega LNG projects by 2030. Pipeline access can directly impact project costs, affecting competitiveness of Canada LNG projects. The Government of Alberta is working with its counterparts, regulators, industry, and industry partners to streamline project approvals, improve pipeline access and get infrastructure built to ship natural gas to international markets.

Energy and Minerals held a discussion among key-ministries on the natural gas and LNG sector in fall 2023 to explore opportunities that support Alberta's natural gas sector, through the LNG industry, and establish a strategic pathway for Alberta's LNG endeavors. The Government of Alberta collaborated with British Columbia and the federal government to preserve and attract new investment to Canada's LNG sector. The partnership also explores leveraging Article 6 of the United Nations Paris Accord, enabling Canada to earn carbon credits for emissions reduction abroad. Collaboration work includes regular information sharing, joint meetings with targeted investors, and supporting Canada's ability to attract investments to the LNG sector. Alberta remains committed to collaborating with British Columbia to decarbonize Western Canadian natural gas.

Did you know?

In 2023, Alberta's natural gas production was one per cent higher than the year before. Alberta was already the ninth largest producer of natural gas in the world and accounted for almost two thirds of Canada's natural gas production. The natural gas industry directly employs tens of thousands of Albertans and many more indirectly working in related sectors, such as petrochemicals. Albertan liquefied natural gas (LNG) will contribute to global emissions reduction efforts as countries are looking to displace higher-emission fuels such as coal in their domestic markets. The governments of Japan and Korea will be seeking the lowest carbon-intensity LNG suppliers to support their own emissions reduction pledges and net zero targets. Shipping from Canada's West Coast to Asian markets takes half the time compared to shipping from the U.S. Gulf Coast. This positions Alberta advantageously to fulfil the emission reduction goals of the Asian market.

The joint efforts aim to showcase the competitiveness of Western Canadian natural gas, which is known for its low carbon intensity, to global buyers. By November 2023, Alberta natural gas producers had several LNG feed gas contracts with U.S. LNG projects. Total contracted volume is about 0.52 billion cubic feet per day (bcf/d), accounting for 5.67 per cent relative to Alberta's gas exports to other jurisdictions, including the U.S., in 2023. The Woodfibre LNG facility, which has a capacity of 0.3 bcf/d, has reached Final Investment Decision and is currently under construction. This development enables Albertan gas to serve as backfill supply.

Minerals Development

In December 2021, the Government of Alberta passed the *Mineral Resource Development Act*, establishing the AER as the full lifecycle regulator for Alberta's metallic and industrial mineral resources, providing clarity and certainty for industry and investors while ensuring the safe and responsible development of Alberta's mineral resources. With the MRDA in full proclamation as of February 2024, Alberta now has a specific resource conservation statute that guide the responsible development of metallic and industrial minerals in the province.

Energy and Minerals continues to work closely with cross-ministry and agency partners to implement the action items identified in the Minerals Strategy and Action Plan. In 2023–24, Energy and Minerals:

- Worked with Indigenous Relations to promote Indigenous-focused initiatives to support mineral development, including funding programs through the Alberta Indigenous Opportunities Corporation, which in October 2023, doubled its loan guarantee capacity to $2 billion, and will increase again to $3 billion in 2024–25.
- Through the Alberta Geological Survey, released targeted geoscience mapping on March 2, 2023, to enhance public geological understanding of Alberta's mineral resources across the province as part of its three-year mapping initiative. New geological data that maps out Alberta's mineral resources to help guide future development continues to be released regularly.

- Continued to support the federal government's Workforce of the Future working group with representatives from Jobs, Economy and Trade and Advanced Education.
- Collaborated with partners in Jobs, Economy and Trade; Invest Alberta; Alberta Innovates; and others to support mining and minerals conferences and to present a united front in working to build Alberta's mining and minerals sector.
- Operated an Alberta Pavilion at a series of mining and mineral conferences. By attending these conferences, Energy and Minerals have directly engaged with proponents, shared key information, and worked to develop business and drive investment in Alberta's mining and minerals sector as part of the Minerals Strategy and Action Plan implementation.

The Western Canada Sedimentary Basin (WCSB) has a long history of oil and gas development, but renewed interest in the WCSB is driven by the exploration and development of critical minerals, particularly helium and lithium. Helium plays a prominent role in medical and technology industries, while lithium feeds the demand for clean energy.

Alberta's Minerals Strategy and Action Plan

The Minerals Strategy and Action Plan will help ensure that Alberta:

- has the opportunity to be at the forefront of global mineral exploration and development;
- can exploit untapped geological potential to meet the increasing demand for minerals;
- has the potential to develop several critical-mineral resources, including lithium, vanadium, rare-earth elements, titanium, and uranium, to help meet clean-energy demand; and
- has Indigenous community and Indigenous business participation in critical-minerals development and resource partnerships.

There are six key areas to support and achieve Alberta's vision for the Mineral Strategy and Action Plan:

- Increase public geoscience.
- Enhance the fiscal and regulatory environment.
- Promote responsible development.
- Advance opportunities for Indigenous Peoples.
- Develop public awareness and a skilled workforce.
- Promote innovation and industrial development.

Critical Minerals

The new Metallic and Industrial Minerals Tenure Regulation, which came into force in January 2023, provides for the management of brine-hosted and rock-hosted minerals in separate tenure regimes to account for each of their unique extraction and refining characteristics. Under the modernized tenure regimes, rights to brine-hosted and rock-hosted minerals will be issued under different agreements with discrete tenure requirements.

As of December 2023, which was the application deadline, Energy and Minerals received 383 applications for brine-hosted minerals licenses from 18 companies involving 5.524 million hectares of land. As of March 2024, Energy and Minerals issued a total of 219 brine-hosted minerals licenses from the 383 applications, covering an area of 1,599,985.8 hectares.

Alberta continues to work collaboratively with the federal government and other provincial and territorial governments through various initiatives, such as the Pan-Canadian Geoscience Strategy, and Canada's Critical Mineral Strategy.

Helium

Canada has the fifth largest helium resource deposits in the world. World helium production in 2022 was estimated to be 160 million cubic metres, with Canada producing about 2.0 million cubic metres.

While the development of the helium industry is in its early stages, the growth potential is high. Alberta's helium reserves are found in the same regions that have historically been known for oil and gas drilling. Helium can be produced as a by-product of natural gas production or directly from dedicated helium wells in selected geological formations.

In March 2023, the Government of Alberta added helium to the list of potential critical minerals. Helium plays a prominent role in medical imaging (magnetic resonance imaging), fiber optics and semiconductor manufacturing, laser welding, leak detection, superconductivity development, aerospace, defence, and energy programs.

Because Alberta produces more than half of Canada's natural gas, the province is well-positioned to become a preferred producer and supplier of helium. The oil and gas industry routinely tests constituent gases in wells. While helium may be found throughout the Western Canada Sedimentary Basin, data has shown elevated concentration in:

- Cretaceous strata in southern Alberta and east-central Alberta (to a lesser extent),
- Devonian strata in southern and west-central Alberta, and
- Cambrian strata in southern Alberta.

Alberta's other advantages include untapped geological potential, a skilled workforce, well-developed and well-positioned infrastructure, and industry expertise.

In 2023, there were seven helium producing wells in Alberta. Aside from Thor Resources' Knappen project, other projects are currently under development, such as those of Imperial Helium, First Helium, and Avanti Energy.

Lithium

Alberta has geological potential across the province for non-energy minerals, many of which have been identified as critical and strategic minerals, including lithium in formation waters in west-central Alberta and in oil sands waste streams.

The World Bank has predicted a 500 per cent increase by 2050 in the production of minerals, such as graphite, lithium, and cobalt, just to feed clean energy demand alone.

Alberta's direct lithium extractors are making advancements in producing battery-grade lithium, utilizing processes that are environmentally friendly as compared to traditional sources.

Alberta currently has several companies undertaking advanced exploration on lithium, including, but not limited to, E3 Lithium Ltd., LithiumBank, and PRISM Diversified Ltd., among others. Alberta is encouraged by federal funding for the critical-minerals sector, including a $27-million contribution to E3 Lithium in 2022, which supported the construction of a demonstration plant that has been operating since August 2023, specializing in lithium production in the province.

Geothermal

Geothermal resource development has one of the lowest emissions of any renewable energy source. It also has the potential to diversify the energy sector and create jobs and economic opportunity for Indigenous and rural-remote communities, while lowering greenhouse gas emissions and contributing to a low-carbon economy.

Alberta's geothermal potential mainly occurs at deep depths, typically three kilometres or more below the surface, and is referred to as "deep geothermal." This contrasts with geo-exchange or "shallow geothermal," which occurs above the base of groundwater protection.

Prior to a geothermal legislative framework, there was a gap in policy defining geothermal energy and guiding development, which led to regulatory uncertainty. Industry, academics, and other stakeholders highlighted the importance of clear legislative and regulatory requirements to have the certainty required to advance deep geothermal projects. The Government of Alberta proclaimed the *Geothermal Resource Development Act* (GRDA) in December 2021, covering deep geothermal resources occurring below the base of the groundwater protection. The Act established the Alberta Energy Regulator (AER) as the single life-cycle regulator for the safe, efficient, and responsible development of geothermal resources in Alberta, clarifies industry requirements and grants the government ability to receive revenues, such as royalties and fees, for geothermal development.

Under the GRDA, the Geothermal Resource Development Regulation was brought into force in January 2022, along with several rules and amendments to other regulations that were needed to enable the development of geothermal resources. This includes the AER's Geothermal Resource Development Rules and consequential amendments to the Oil and Gas Conservation Rules, which took effect on June 2022.

The Geothermal Resource Tenure Regulation also came into effect on January 1, 2022, which guides the tenure of geothermal leases in Alberta. This regulation addresses the issuance and administration of Crown geothermal leases, including the obligations of lessees under leases. Since the new regulations took effect and up until December 2023, the Alberta government has received 113 applications for tenure and issued 74 leases.

Alberta is seeing a growing interest from companies in developing projects across the province, such as Eavor's Derek Riddell Eavor-Lite Demonstration Facility, located near Rocky Mountain House, is a full-scale prototype of the Eavor technology suite constructed in 2019. Other geothermal projects proposed or under way in Alberta include Renewable Geo Resources' project near Edson and the Alberta No.1 project near Grande Prairie.

Maps to Minerals Program

To support Alberta's Minerals Strategy and Action Plan, the objective of Alberta Energy Regulator's (AER) multi-year Mineral Mapping Program is to collect new information and data to improve the characterization and understanding of Alberta's mineral potential. The data and information products produced from this work will be used to highlight new areas of mineral potential that may stimulate exploration and development, which in turn supports potential investment and job creation in Alberta. The overarching objective of the Mineral Mapping Program is to provide a better understanding of Alberta's diverse mineral resource potential by improving access to transparent and reliable geological and mineral data and information products. More details about the Mineral Mapping Program are in the vision presented in Minerals Strategy and Action Plan: open.alberta.ca.

The Mineral Mapping Program includes the collection and public release of raw data, interactive maps, technical reports, journal publications, and public presentations. In 2023–24, the department continued contributing to the Mineral Mapping Program to collect data on critical minerals in strategic locations across Alberta to improve our characterization and understanding of Alberta's mineral potential.

The Alberta Geological Survey (AGS) is the official provincial geological survey in Alberta and operates as a division under the AER, providing geological information and advice to the Government of Alberta, the AER, industry and the public to support exploration, sustainable development, regulation, and conservation of Alberta resources. Data acquired by AGS, as of March 31, 2024, includes:

- Airborne Geophysics (magnetic and gravimetric): The AGS surveyed over 1 million line-kilometres, which covered large regions of Alberta and acquired new data in strategic locations of Northern and Southern Alberta.
- Magnetotelluric Study: The AGS collaborated with the University of Alberta to complete 3D models of deep-seated geological features within the kimberlite corridor, which can highlight areas of increased diamond potential.
- Core scanning:
  - Over 51,000 metres of core
  - PXRF: 75,000 sample points
- Rock Sampling:
  - Microprobe Analysis: 9,800 grains
  - Till and Alluvium: 1,350 sample sites
  - Rock Pulp XRD analysis: 703 samples
  - Lithogeochemical analysis: 2,811 samples
  - Heavy Mineral Concentrate Analysis: 850 samples
- Historical Record digitization:
  - 329 reports mineral assessment reports
- Remote Sensing imagery over Clear Hills and Grande Prairie
- Oil field and groundwater sampling from 312 oil and gas wells

Did you know?

The Alberta Geological Survey conducted an airborne geophysics program between 2021 and 2023. Airborne geophysics is an environmentally friendly way to survey large areas, as it does not disturb the land.

The Airborne Geophysics project is one of the largest single-acquisition airborne geophysical survey acquisitions in Canadian history and the largest mineral data acquisition (in both scale and scope) in Alberta's history.

As of March 2024, the AER published 14 overview documents regarding major project thematic areas highlighting the following:

- data that was collected,
- how it improves understanding of Alberta's mineral potential, and
- where data was collected.

In addition, releasing data regarding mineral resource potential in Alberta has attracted interest from new groups of stakeholders. This interest provided the AGS project teams with an opportunity share the newly acquired mineral mapping program data and products at the following events:

- Geological Society of America Annual Conference, Pittsburgh: October 16–18, 2023;
- Rural Municipality Association Conference and Tradeshow, Edmonton: November 6–9, 2023;
- Association for Mineral Exploration Round Up, Vancouver: January 22–25, 2024; and
- Prospectors & Developers Association of Canada, Toronto: March 3–6, 2024.

Carbon Capture, Utilization, and Storage

For large stationary sources of carbon dioxide (CO_2), like gas-fired generating units and petroleum refineries, use of carbon capture, utilization and storage (CCUS) can help redirect CO_2 emissions before they enter the atmosphere. Captured CO_2 is injected into locations deep underground for safe, permanent storage. CCUS is a necessary, developing part of reducing emissions, and the government recognizes the value that CCUS will bring to Alberta, playing a critical role in a low-carbon economy.

Large-scale CCUS development requires significant investment to develop and operate, which highlights the importance of attracting CCUS investment to accelerate the deployment and retain Alberta's position as a global leader in the technology. CCUS incentives provided by the American *Inflation Reduction Act* have made development in the United States attractive for industry. In response, Energy and Minerals has been working with the federal government to provide more financial supports for CCUS projects, maintain Alberta's competitiveness, and attract investment. Energy and Minerals also worked with other ministries and organizations, such as Invest Alberta and domestic and international companies, to attract carbon capture investment and opportunities to export Alberta's CCUS technologies and expertise.

The Carbon Capture, Utilization and Storage Process:

Carbon dioxide (CO_2) is separated and collected from emissions produced by industrial activity, then compressed and transported to a storage site and injected into carefully selected, secure underground geological formations that can safely and permanently store the gas. After injection activity ends at the site, the site is tightly sealed and monitored to ensure there are no safety or health risks to the public or to the environment.

Alberta has the ideal geology for carbon capture, utilization and storage (CCUS) and rock formations that have securely stored oil and gas for millions of years can also safely store CO_2 permanently. Research demonstrates that various geological trapping mechanisms will safely contain the CO_2 deep underground.

CCUS is critical to meeting Canada's long-term energy needs and climate goals. Alberta is among the global leaders in developing CCUS technology. The International Energy Agency and other sources say that, without substantial support to further develop and employ this technology, it will be difficult for Canada to meet its emission reduction targets.

The Alberta Petrochemicals Incentive Program, which provides grants to new hydrogen and petrochemical projects in Alberta, requires a CCUS component for projects that produce hydrogen or fuels from natural gas sources. The Air Products Hydrogen Production and Liquefaction Facility in Edmonton was the first hydrogen project to meet this requirement. The facility will produce net-zero hydrogen and its use in downstream markets will result in overall full life-cycle CO_2 emissions reductions of approximately 1.4 million tonnes per year. The facility is expected to be completed in late 2024.

2008 Carbon Capture and Storage Program

In 2008, the Government of Alberta committed $2 billion to establish a Carbon Capture and Storage (CCS) Program Fund to incent the development of CCS large-scale projects in Alberta, with the objective of storing up to 5 million tonnes of carbon dioxide (CO_2) per year and reducing 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 (ACTL) projects. Funding of $1.24 billion is allocated to both projects to the end of 2025 to capture approximately up to 2.76 million tonnes of CO_2 each year. This is roughly equivalent to annual emissions of 600,000 vehicles. Over 2023–24, annual injection payments for the ACTL and the Quest projects totalled approximately $20 million. The amount of the greenhouse CO_2 emissions reductions that each project's annual injection payment is based on is certified by third party verifiers.

Quest Project Update: The Quest project is capturing approximately a million tonnes of CO_2 per year from the Shell Scotford Upgrader, transporting it 65 kilometres north by pipeline, and permanently storing it underground in a deep saline aquifer. The Quest project completed its eighth year of CO_2 injection. Since entering operation in 2015, the project has exceeded its targets for the capture and safe, permanent storage of CO_2 at a lower-than-anticipated cost. Shell Canada Energy, the project operator for the Quest project, has noted that the project has captured and stored over eight million tonnes of CO_2.

Alberta Carbon Trunk Line Update: The Alberta Carbon Trunk Line (ACTL) project is transporting over one million tonnes of CO_2 per year, captured from the North West Sturgeon Refinery and the Nutrien Redwater Fertilizer Plant, through a 240-kilometre pipeline for use in enhanced oil recovery in Clive, Alberta. The pipeline has the potential to transport up to 14.6 million tonnes of CO_2 annually. Since entering operation in 2020, the ACTL project has completed its third year of CO_2 injection. Enhance Energy Inc., the sequestration site operator for the ACTL project, has noted that the project has captured and sequestered over 4 million tonnes of CO_2.

In February 2024, a Request for Proposals was posted for services from a third-party independent verifier to confirm the net tonnes of CO_2 sequestered by the ACTL project for injection years four, five, and six. The preferred proponent was selected in March and has begun the certification work.

Yearly presentations and annual reports are also completed by the recipients. Learnings for both projects are shared through a Knowledge Sharing Program that helps to reduce the future costs of CCUS and to encourage the broader adoption of this technology around the world. Summary and Detailed Reports for the Knowledge Sharing Program were submitted by the recipients in March.

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 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. Carbon sequestration agreement holders are required to contribute to the fund. The amount paid into the fund by companies awarded sequestration rights is based on a project-specific rate per tonne of carbon dioxide injected into the sequestration lease each year.

To date, the Post-Closure Stewardship Fund has collected eight annual injection levy payments from the Quest project, and with $586,999 in revenues generated from the injection levy during 2023–24, the fund is currently valued at $2.86 million.

The Quest project is currently the only carbon sequestration project paying into the fund. Since the Alberta Carbon Trunk Line is an enhanced oil recovery project, it holds a conventional petroleum and natural gas lease and does not pay into the Post-Closure Stewardship Fund.

Carbon Capture, Utilization and Storage Tenure Management

Energy and Minerals has received significant interest from industry for the right to use pore space for the sequestration of carbon dioxide (CO_2). The pore space used for carbon capture, utilization and storage (CCUS) requires secure underground geological formations that can safely and permanently store the captured CO_2. Ensuring a well-defined and strategic approach to make sure CO_2 storage options are available and accessible to all industries is essential to meet current and future demand.

The province is facilitating the deployment of carbon sequestration hubs. A carbon sequestration hub is an area of pore space overseen by a private company that can effectively plan, enable, and undertake carbon sequestration of captured CO_2 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.

To help meet the growing demand for carbon storage, the Government of Alberta issued two Requests for Full Project Proposals (RFPP) for carbon sequestration hubs in Alberta, the first in December 2021, which resulted in six successful proposals in the Industrial Heartland region, and the second in March 2022, which resulted in an additional 19 successful proposals being selected in October 2022 from regions across Alberta.

Following the RFPPs, Energy and Minerals executed Carbon Sequestration Evaluation Agreements for the successful carbon storage hub projects proposals and collected approximately $9.8 million in Evaluation Agreement rental fees. The agreements allow companies to work with the government to further evaluate the suitability of their locations for safely storing carbon from industrial emissions. Throughout the evaluation process, companies are expected to identify and address potential conflicts with other subsurface interests and undertake various regulatory approvals, consultation, and business development activities. Operators will also be responsible to obtain regulatory approvals from the Alberta Energy Regulator for the capture, transportation, and subsurface injection activities of CO_2. Alberta's CCUS regulatory approval process requires careful site selection, numerous approvals, rigorous monitoring and reporting requirements, and public involvement processes.

If the evaluation demonstrates that the proposed projects can safely provide permanent storage, companies will be invited to work with the government on an agreement that provides them with the right to inject captured CO_2. When fully developed, the hubs will allow operators to safely collect, transport and permanently store captured CO_2 from industrial emissions sources across the province.

With the confirmation of Canada's CCUS Investment Tax Credit last fall, it is anticipated that major construction on some projects could begin in 2024–25.

Along with developing storage hubs, Alberta's government worked to advance carbon sequestration tenure processes for scenarios that may not be met through a hub. An ongoing tenure application process was established that would support small-scale and remote carbon sequestration scenarios. The application process will facilitate the granting of two agreements:

- A tenure agreement that grants the right to sequester carbon dioxide into a subsurface reservoir (pore space).
- A unit agreement that addresses the varying interests and activities within the location, including Crown interests.

As with other subsurface development activities, small-scale carbon sequestration proponents will be required to undertake various approvals and stakeholder notification processes.

Monitoring, Measurement, and Verification (MMV)

Monitoring and measurement are surveillance activities necessary for ensuring the safe and reliable operation of a carbon dioxide (CO_2) sequestration project. Verification refers to the comparison of measured and predicted performance, which is also known as conformance. The purpose of monitoring, measurement, and verification (MMV) is to address health, safety, and environmental risks, evaluate sequestration performance and provide evidence that the site is suitable for closure. MMV is central to CO_2 sequestration risk management.

An MMV plan sets out the monitoring, measurement, and verification activities that a project proponent will undertake for the term of the evaluation permit or carbon sequestration lease. In early April 2023, an updated version of the MMV plan "principles and objectives" document was published to provide greater clarity about risk management plans and risk assessment expectations. On April 25, 2023, the Government of Alberta delegated the oversight of the MMV plans; closure plans; and closure certificates for carbon capture, utilization and storage (CCUS) activities in the province to the Alberta Energy Regulator (AER). The AER has amended references and submission requirements for the MMV and closure plan submissions in Directive 065: Resources Applications for Oil and Gas Reservoirs. Energy and Minerals participates in the Alberta Energy Regulator's review of the MMV and closure plans for the Quest project and the MMV plan for the ACTL project.

Alberta Carbon Capture Incentive Program

In November 2023, the Government of Alberta announced Alberta Carbon Capture Incentive Program (ACCIP) to support and accelerate the development of new carbon capture, utilization, and storage (CCUS) infrastructure by providing incentives for facilities to incorporate this technology into their operations. ACCIP will support industries who are facing challenges to reduce emissions, such as oil and gas, power generation, hydrogen, petrochemicals, and cement production, by providing a grant amounting to 12 per cent of new eligible CCUS capital costs. Like the process used by the Alberta Petrochemicals Incentive Program, grants will be paid to operators in three installments over three years, starting after one year of operations. Eligible CCUS projects must be physically located in Alberta and include those that capture, prepare, compress, transport, store or utilize carbon dioxide. CCUS projects will be retroactively eligible to January 1, 2022. More details about ACCIP and project eligibility are available at: www.alberta.ca/alberta-carbon-capture-incentive-program.

The program is expected to provide between $3.2 to $5.3 billion of support between 2024 and 2035, accessing a portion of its funding from the Technology Innovation and Emissions Reduction fund. Final amounts depend on the development timelines of these large capital-intensive projects, which are still to be determined. The program is being designed to build on the federal CCUS Investment Tax Credit, leveraging an estimated $18 billion in federal funding. ACCIP funding will be available once the federal government has legislated its CCUS Investment Tax Credit and related operating supports, such as contracts for difference.

ACCIP was under development throughout 2023–24, and Energy and Minerals is planning to engage with stakeholders over April and May 2024. Engagement will inform the finalization of technical guidance documents for the program. Developing CCUS is a key component of Alberta's Emissions Reduction and Energy Development Plan, which sets the path to reach emissions targets while encouraging sustainable economic growth in the province. Over the next decade, the government expects ACCIP to attract $35 billion in new investment and create up to 21,000 jobs.

Nuclear Energy and Small Modular Reactors

Nuclear energy, including Small Modular Reactors (SMR), has the potential to supply non-emitting energy in many different applications and could diversify the economy, create new jobs, and reduce emissions. SMRs are much smaller than traditional nuclear reactors and are scalable to suit local needs, with lower upfront capital costs and enhanced safety features. SMR technology could lower emissions and diversify the province's energy sector. Alberta's oil sands producers have expressed interest in using SMRs to reduce emissions. As well, there is an opportunity for SMRs to be used in petrochemicals production to help decarbonize the sector.

Within Energy and Minerals' mandate letter, the ministry was tasked with the following three actions regarding SMR:

- develop and improve regulatory regimes to incentivize investment in hydrogen, ammonia, helium, lithium, liquefied natural gas, small modular reactors, geothermal, and mineral development in Alberta;

- coordinate with other provinces and the federal government to further explore and promote small and micro modular reactor technologies and pave the way for their use in oil sands operations and petrochemical production; and
- collaborate with the Environment and Protected Areas (EPA) to develop and implement a regulatory framework for small modular reactor technology use in Alberta.

In May 2023, the Government of Alberta's Nuclear and Small Modular Reactor Working Group was established. Led by Energy and Minerals, this table brings together ministry and agency partners across the Government of Alberta—including Affordability and Utilities, EPA, Municipal Affairs, Indigenous Relations, Alberta Innovates, Invest Alberta, and Emissions Reduction Alberta—to share information, maintain situational awareness, and collaborate on matters related to nuclear and SMR development in the province.

Any future adoption of SMR technology in Alberta would require an extensive regulatory and engagement process. The province is currently working to ensure the regulatory framework is in place and when ready, should private industry pursue this technology.

Sturgeon Refinery

Sturgeon Refinery commenced commercial operation on June 1, 2020, and began processing bitumen into diesel with a capacity of 79,000 barrels per day (bpd) of feedstock, increasing Alberta's total refinery capacity to 533,000 bpd.

The Sturgeon Refinery continues to work to maximize operating cash flows while maintaining safe and reliable operations and is processing an average of approximately 75,000 bpd of feedstock, producing almost 40,000 bpd of ultra-low sulphur diesel for both Alberta and Western Canada. In addition to producing one of the cleanest low-carbon diesels in North America, the refinery is also the world's only refinery designed from the ground up with an integrated carbon-capture solution.

The Alberta Petroleum Marketing Commission (APMC) is a 75 per cent toll payer and a 50 per cent owner in Sturgeon Refinery. As a toll payer, the APMC provides 75 per cent of the feedstock and receives 75 per cent of the refinery sales at the Sturgeon Refinery.

As of March 2023, approximately 4.2 million tonnes of carbon dioxide (CO2) were captured since the start of commercial operations in June 2020. Of that amount, 1.24 million tonnes of CO2 were captured during 2023–24 fiscal year, making APMC, through the Sturgeon Refinery and its integrated carbon capture technology, one of the largest CO2 sequesters in Alberta, supporting the provinces transition to a low-carbon future.

Further details on the refinery's performance can be found on the APMC website at www.apmc.ca and the North West Redwater Partnership website at www.nwrsturgeonrefinery.com.

Methane Emissions

Energy and Minerals supports Environment and Protected Areas and the Alberta Energy Regulator (AER) to develop policies and regulation for methane emissions. This includes considering opportunities within existing directives to reduce red tape.

In November 2023, the AER reported that Alberta achieved its goal of reducing methane emissions 45 per cent below 2014 levels. This target was achieved in 2022, which was accomplished three years before the original 2025 target. The requirements under Alberta's Methane Emission Reduction Regulation, market-based incentives, and Technology Innovation and Emissions Reduction programming, supported the achievement of Alberta's 45 per cent methane reduction target.

In November 2023, the federal government published its updated draft regulations to reduce methane emissions across Canada by 75 per cent below 2012 levels and targets achievement by 2030. Alberta maintained its provincial jurisdiction by establishing an equivalency agreement with the federal government for the current Methane Emission Reduction Regulation. This supports Alberta to regulate its own resources and pursue pathways to reduce methane emissions that are more effective and efficient for the province. By structuring its own regulations and pathways, Alberta reduces unnecessary duplication, administrative burden, and extra costs from having a separate federal system in place. Relative to the federal system, Alberta's current regulations are estimated to reduce more methane emissions by 2025, and at half the cost to industry.

In April 2023, the Government of Alberta released the Emissions Reduction and Energy Development Plan, which includes a commitment to assess potential pathways that will reduce methane emissions in the conventional oil and gas sector by 75 to 80 per cent below 2014 levels. The potential pathways will target 2030 for achievement and will focus on using a combination of regulations, market-based incentives, and programs, complemented by continuous improvement in measurement and reporting.

1.2 Enhance Alberta's investment climate through measures that improve the province's standing with investors, by:

- promoting the province as a safe, secure, and sustainable producer of energy, reinforcing Alberta's long-standing commitment to responsible and innovative energy resource development, and communicating energy industry performance; and
- working with other ministries, First Nations, Metis Settlements, other Métis communities, and Indigenous organizations to support Indigenous participation and partnerships in the natural resource and energy economy, including regional development in rural areas.

Environmental, Social, and Governance Performance

Environmental, Social, and Governance (ESG) criteria are used by investors, financial institutions, and talent to screen potential investment opportunities, highlight corporate behaviour, and identify material risk traditionally left undisclosed. ESG criteria are non-financial performance measures used to assess the sustainability, societal impact, and risk of a particular investment.

The ESG Secretariat was created in May 2021, as part of Executive Council, based on strategic analysis and recommendations put forward by Energy and Minerals to address divestments that were happening at the time because of incorrect depictions about the ESG characteristics of Alberta and the oil and gas sector.

Alberta's continues its position as a leader in ESG performance and demonstrating the critical role Alberta's resources, technology, and diverse energy mix will play in the global energy future. Regardless of criticisms that ESG-based investing has received in 2023 from some legislators in the U.S., global investors still consider ESG results — particularly environmental ones — in their investment decisions across all sectors. Energy and Minerals is committed to ESG by:

- working with key stakeholders to ensure a unified approach that highlights Alberta's ESG strengths, such as strong environmental practices, leadership on social issues including Indigenous participation, and transparent governance practices;
- implementing Alberta's Natural Gas Vision and Strategy, which highlights the potential for expanded natural gas development and investment in hydrogen, exports of natural gas and liquefied natural gas, petrochemical diversification, plastics recycling, and carbon capture utilization and storage; and
- monitoring international and national developments in ESG, climate disclosure and reporting frameworks, and emerging sustainable finance markets to ensure Alberta companies can continue to attract the

Environmental, Social, and Governance

Global investors with significant capital and strong Environmental, Social, and Governance (ESG) due diligence practices are still interested and investing in oil and gas sector opportunities as part of the larger net-zero energy transition. Approximately 82.8 per cent of the U.S. equity mutual and exchange-traded funds that have a "sustainable" label contain some holdings in oil and gas companies.

Oil and gas companies in Alberta, including all Pathways Alliance members, have rapidly adopted comprehensive ESG reporting practices and publish extensive annual ESG result reports. As a result of technological innovation, Alberta's oil sands producers have reduced emissions per barrel by 36 per cent since 2000 (20 per cent over the past decade), with leading producers on track for another 20 to 28 per cent reduction by 2035. The carbon intensity of crude oil from many oil sands projects is now equal to or lower than the average for a barrel of crude globally. In 2022, total emissions from oil sands production remained flat relative to 2021, even though output grew during that same period.

investment needed to meet their emission reduction targets and capitalize on emerging opportunities in renewable energy and low-carbon technologies and markets.

Canadian Energy Centre (CEC)

The CEC has a mandate to promote the Canadian energy industry, respond to misinformation about Canadian oil and natural gas; create original content to elevate the general understanding of Canada's energy sector; and centralize and analyse data that targets investors, researchers, and policymakers. A three-member board oversees the CEC's activities and operations, and consists of the Ministers of Energy and Minerals, Environment and Protected Areas, and Justice.

Through 2023–24 the CEC has continued to focus on its mandate, including:

- addressing misinformation through social media and legacy media regarding Alberta's resources, industry and performance on environmental, social, and governance matters;
- creating and maintaining a steady stream of original articles, video, photo, graphics – to improve understanding of all aspects of Alberta's energy sector and to ensure the province is in front of its energy story; and
- centralizing and analysing data to re-enforce Alberta's responsible energy story with evidence important to investors, researchers and policy makers.

The CEC reinforces Alberta's long-standing commitment to communicating the province's performance in responsible, ethical, and innovative energy resource development. The CEC's primary focus is marketing activities, and much of its performance is based on engagement and interaction with the public. Performance targets and metrics are published online in its annual report.

For more information, visit: www.canadianenergycentre.ca/annual-reports/

Indigenous Participation

Indigenous communities are playing an important role as owners and partners in major development projects and in the non-renewable resources and energy sectors at large. Indigenous participation in resource development is not just an economic imperative; it is also an opportunity to deliver practical measures for Indigenous Peoples to be substantial partners in Alberta's resource economy. Having strong relationships between Indigenous communities, government, and industry within the energy resource development sector can also help to strengthen the province's standing with investors.

Energy and Minerals issued $1 million in grants to Indigenous organizations. The grants are administered from Budget 2023 and are to be spent and reported on from the organizations by March 31, 2025. The organizations are to submit two sets of reports to the department that describe how the funds were spent and that show progress on deliverables outlined in the grant agreements.

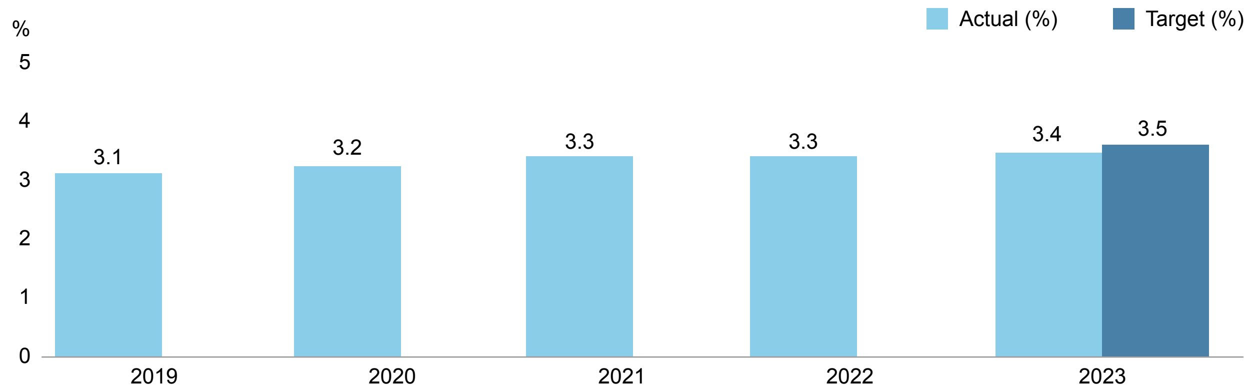
In January 2024, the Energy and Minerals Contract Review Committee approved $1 million in grants to be distributed to the Indian Resource Council (IRC) and the Metis Settlements General Council (MSGC), with each amounting to $850,000 and $150,000 respectively. The funds will be used to build capacity within Indigenous communities to identify and assess participation opportunities in energy and minerals development.

The IRC requested the funding to continue to support and provide increased knowledge sharing related to energy transition with Alberta First Nations peoples on a range of net-zero initiatives. The MSGC requested the funding to increase overall participation in the energy sector and to develop strong economic growth partnerships across Settlements.

The IRC and MSGC were selected as the Indigenous organizations to receive these grants because they are in unique positions to reach many First Nations and Métis peoples in Alberta to support Indigenous participation in the natural resource economy. The impact of these grants has the potential to benefit many Indigenous peoples in Alberta with the scope and breadth of these organizations.

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

Target: 3.5 per cent[6] of global oil consumption is supplied by Alberta's oil sands.



Sources: Alberta Energy Regulator; International Energy Agency[7]

Discussion of Results

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

There are several levers that indirectly affect the results of the measure. Key levers available to the Government of Alberta to influence the results of this measure are the fiscal and royalty regimes, which directly act to incentivize industry's resource-development activities while ensuring that Albertans receive direct financial benefits in the form of taxes and royalties. Other government policies influence industry performance and oil-sands production levels: promoting market access, intergovernmental relations, energy research and development, and environmental regulations.

The 2023 supply share was very similar to the share in 2022, but was marginally larger, and as a result of rounding, went up to 3.4 per cent.[8] The supply share has remained generally static over the past three years. Although the 2023 share was below the target of 3.5 per cent, it was within the accepted range of plus or minus 0.2 per cent. Both Alberta crude bitumen production and the total global consumption increased from 2022 to 2023. While the rate of growth in Alberta's total crude bitumen production exceeded the rate of growth in global consumption from 2022 to 2023, the difference was not sufficiently high to push the ratio to the target level. The rate of global year-over-year oil consumption increased by 2.2 per cent, from 99.5 million barrels per day[9] (bpd) in 2022 to 101.7 million bpd in 2023. Global oil demand increase was driven by the demand growth in non-Organization for Economic Cooperation and Development (OECD) regions. Global demand in OECD regions slightly increased from 2022 to 2023 but remained virtually the same.

Total crude bitumen production in Alberta also increased from 2022 to 2023, from 3.32 million bpd to 3.41 million bpd, an increase of about 2.6 per cent. The production result in 2023 was an annual record, exceeding the previous record that was set in 2022.

The increase in total crude bitumen production from 2022 to 2023 was larger than the increase from 2021 to 2022, which was driven by the fact that the impacts of COVID-19 declined since the onset of pandemic in 2020. The bitumen production growth between 2022 and 2023 is reflective of oil sands producers increasing

[6] Due to an administrative error in the 2023–26 Business Plan, the years for each target in Performance Measure 1.a are one year less than the correct date. This resulted in the target for 2023–24 being 0.1 per cent higher than the correct target. This has been corrected in the 2023–24 Annual Report, resulting in the target for 2023–24 being updated to 3.5 per cent

[7] For more information, see the Performance Measure and Indicator Methodology section of this report on page 79.

[8] The 2020 historical result has been retroactively revised from 3.3 per cent to 3.2 per cent. The 2020 result for the performance measure was reported in the 2022–23 Annual Report at 3.3 per cent. Retroactive downward adjustment to the result of the measure for 2020 took place due to the upward adjustment of the world oil demand.

[9] Previously, the 2022–23 Annual Report reported 99.9 million bpd of global oil consumption for 2022. This volume has been retroactively revised down to 99.5 million bpd.

production in advance of the start up of the Trans Mountain Expansion Project. The anticipation of increased pipeline capacity facilitating market access for increased production is a strong motivating factor for oil sands operators in 2023, even though the Trans Mountain Expansion Project was not completed in 2023.

Both mined and in situ production experienced a production increase from 2022 to 2023, although in situ production grew at a faster pace. Year-over-year growth rates were 3.4 per cent for in situ production and 1.9 per cent for mined production. In situ production increased from 1.70 million bpd in 2022 to 1.76 million bpd in 2023, and mined production increased from 1.62 million bpd in 2022 to 1.65 million bpd in 2023. While the growth rate from 2022 to 2023 was faster in the in-situ sector than the rate of growth in international oil consumption, the rate of growth in mining sector was lower than the rate of international oil consumption growth.

The proportion of in situ and mined production in Alberta in 2023 slightly changed from the previous year. In 2022, as 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. In 2023, in situ production and mined production accounted for about 52 per cent and 48 per cent, respectively.

Outcome Two:

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

The ministry will improve the clarity and efficiency of Alberta's energy regulatory system, while modernizing legislation and regulations and streamlining and speeding up application approval processes to enhance the competitiveness of the Alberta energy sector 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

2.1 Maintain provincial jurisdiction and enhance regulatory certainty for Alberta's energy resources.

Federal Engagement and Provincial Jurisdiction

Energy and Minerals regularly engages with the federal government, stakeholders, and other provinces, through letters, technical submissions, and strategic engagement. Alberta has expressed concerns about federal policies that intrude on areas of provincial jurisdiction, such as the *Impact Assessment Act*, Clean Electricity Regulations, Oil and Gas Emissions Cap, and Methane Regulations.

This work enhances regulatory certainty, supports market access and investment attraction for Alberta's energy resources, and advances the implementation of carbon-reducing solutions to achieve Alberta's aspiration of reducing emissions and reach net-zero by 2050. Carbon-reducing solutions include carbon capture, utilization, and storage; clean ammonia exports; mineral development; and nuclear and small modular reactors.

In 2023–24, the Government of Alberta participated in federal consultations on Canada's Critical Minerals List and Methodology and Canada's Supply Chain Regulatory Review on Critical Minerals. Alberta provided input regarding updating criteria that will define mineral criticality for Canada and to address Canada's supply chain vulnerabilities, positioning the country as a secure and reliable supplier of critical minerals for domestic and global supply chains.

In March 2024, the Alberta-Canada Bilateral Table on Small Modular Reactors (SMRs) and the Alberta-Canada Bilateral Table on Critical Minerals were established after the Terms of References were signed by the Deputy Minister of Energy and Minerals and the Deputy Minister of Natural Resources Canada, supporting collaboration between Alberta and Canada on SMRs and critical minerals development, focusing on actionable short-term initiatives with tangible outcomes. Alberta and Canada are now working collaboratively to develop and finalize a joint work plan. Energy and Minerals also advocates for Alberta's oil and gas market interests through participation in industry committees, Canada Energy Regulator (CER) proceedings regarding federally regulated energy infrastructure and service applications, and the Energy and Minerals-CER working table. It also engaged in federal advocacy through mechanisms such as the Energy and Mines Ministers' Conference.

This work communicates provincial interests within CER processes and supports Energy and Minerals' objectives to strengthen market access for Alberta's natural resources. In 2023–2024, this included:

- Intervening at the CER hearing to advance Alberta's interest in the North River Midstream NEBC Connector Project, Enbridge Inc., Canadian Mainline Tolling Settlement, Nova Gas Transmission Ltd. (NGTL) Willow Valley Interconnect Project, NGTL Firm Transportation-Linked North Montney application, and Trans Mountain Expanded Pipeline Interim Commencement Date Tolls application.
- Continuing to participate in industry committees, such as Enbridge Mainline Committee, NGTL Tolls Tariff Facilities and Procedures subcommittee, Trans Canada Mainline Toll Task Force, and Westcoast Toll and Tariff Task Force.
- Regularly monitoring oil and gas facilities applications before the CER and the Impact Assessment Agency of Canada; and
- Holding discussions with the CER via the Energy-CER working table to resolve concerns outside of the CER's hearings.

Opportunities in emerging resources (e.g. hydrogen), geopolitical shifts, and increasing concerns regarding energy security, energy prices, and climate change, are ongoing developments that will likely lead to evolving regulatory frameworks in Canada, the U.S. and overseas, which may impact Alberta's market interests. Energy and Minerals will continue to advocate for improving Alberta's market access as trends and new developments evolve.

Federal Oil and Gas Emissions Cap

On December 7, 2023, the Environment and Climate Change Canada (ECCC) published a proposed framework for the federal Oil and Gas Emissions Cap (OGEC), outlining a cap-and-trade regulatory system to be implemented under the *Canadian Environmental Protection Act*, 1999, for upstream oil and gas, bitumen upgrading, natural gas processing, and liquefied natural gas facilities. The ECCC requested feedback on from the provinces and industry on the draft regulation.

Energy and Minerals collaborated with Environment and Protected Areas (EPA) and Treasury Board and Finance to analyse the economic assumptions and impacts the proposed OGEC framework would have on Alberta.

On February 5, 2024, written feedback from EPA and Energy and Minerals was provided to the federal government. In this feedback, the province communicated that:

- Alberta is efficiently and effectively regulating and driving emissions from all industrial sectors, including oil and gas. Therefore, the draft regulation is not needed.
- The proposed OGEC unfairly targets Alberta's oil and gas industry which has made significant reductions in emissions intensity in recent years.
- Alberta's technical submission does not alter the province's position that the proposed emissions cap is unconstitutional. As set out in Section 92A of the *Constitution Act*, *1867*, Alberta has exclusive jurisdiction to manage the rate of non-renewable natural resources production and operational aspects of their development in our province.

Draft regulations for the federal OGEC expected to be published in mid-2024 for comment, followed by final regulations in 2025 and implementation in 2026.

The 2030 emissions cap level, equivalent to the total emissions allowances issued under the cap-and-trade system, is set at 35 to 38 per cent below 2019 levels, or 106 to 112 megatonne (Mt).

The 2030 legal upper bound, which is the maximum emissions the sector will be allowed to emit, is set at 20 to 23 per cent below 2019 levels or 131 to 137 Mt, including 25 Mt of flexible compliance above the emissions cap level.

Clean Fuel Regulation

The federal Clean Fuel Regulation (CFR) is intended to reduce the emissions intensity from liquid fuels used in Canada by approximately 15 per cent below 2016 levels by 2030. In June 2021, the federal government narrowed the scope of the CFR to only include gasoline and diesel, as opposed to all liquid fuels.

Alberta has pushed for changes to the federal CFR since 2017 to address the potential impacts of a CFR, such as reduced investment, revenue, jobs, and the competitiveness of Alberta's trade-exposed industries. Provincial, territorial, and industry feedback to the federal government has resulted in significant changes to the scope of the CFR along with technical changes that have reduced the negative impacts expected from the regulation's original design. For instance, the potential implications of the CFR on the Alberta electricity and natural gas sectors are minimal with the removal of the gas and solid fuels and limitations placed on credit generation opportunities for low-carbon intensity electricity. In 2023–24, Alberta continued to work with the federal government regarding the final treatment of hydrogen under the CFR. Energy and Minerals also continued to support Alberta in advocating for policy refinements that benefit Alberta's environment while recognizing our province's unique economic needs and circumstances.

Although Alberta successfully advocated for changes to the CFR, Alberta's concerns regarding the potential impacts include:

- the impacts to low-income households and potential for lost revenue;
- the federal government's decision to exclude exported crude and finished products from credit opportunities;
- increasing costs and compliance burden for the energy sector;
- the potential transfer of investment and capital from Alberta to other jurisdictions; and
- lack of flexibility associated with using CFR credits and/or compliance fund options, which are otherwise needed to ensure the CFR can effectively adapt to unforeseen market changes.

Energy and Minerals and Environment and Protected Areas collaborated to model the impacts of the CFR, which indicate that its direct impacts will:

- decrease output for in-situ oil sands by 0.9 per cent, oil refineries by two per cent, and freight transport by 2.1 per cent;
- add incremental costs of 6 to 13 cents, and 7 to 16 cents per litre of gasoline and diesel, respectively, in 2030; and
- result in a $9 billion impact to gross domestic product (GDP) and shrink Alberta's GDP by -0.4 per cent.

Modelled costs only assess direct impacts and do not consider second order effects from long-term demand destruction, meaning the estimated impacts to Alberta's GDP likely only represent a portion of the total costs. While the CFR could lead to investment opportunities in the oil and gas sector, such as with carbon capture and storage, bio crude co-processing, hydrogen production, and low carbon electricity, the current design does not provide investment certainty required for projects to begin construction.

Sustainable Jobs Plan

In June 2023, the federal government introduced Bill C-50, the *Canadian Sustainable Jobs Act*. Bill C-50 seeks to establish a governance structure and framework to guide future federal sustainable jobs policy and programs, concurrent with current federal emissions reductions and net-zero initiatives. The Sustainable Jobs Partnership Council is expected to be established and begin engagement in mid-to-late 2024, with the first Sustainable Jobs Plan expected by the end of 2025.

In 2023–24, Energy and Minerals advocated for the withdrawal of the federal government's Sustainable Jobs Plan and worked with provinces to pursue the development an alternative program that attracts energy investment and workers into Alberta's conventional, non-conventional, and emerging energy sectors while reducing emissions.[10]

2.2 Collaborate with other ministries within the Integrated Resource Management System to maintain and strengthen a balanced, responsible approach to managing the impacts of resource development activities, including the ongoing implementation of liability management activities.

Liability Management Framework

The Government of Alberta announced the new Liability Management Framework (LMF) in July 2020. 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. Energy and Minerals, the Alberta Energy Regulator (AER), Environment and Protected Areas, and industry have collaborated over the last year to operationalize the elements of the new framework in a phased approach.

- The **Holistic Licensee Assessment** uses a multifactor approach to assess the capabilities of oil and gas operators to meet regulatory obligations at each stage of the development life cycle, prior to receiving regulatory approvals. It includes the licensee capability assessment factors, which considers a variety of factors that the AER uses to evaluate a company. This includes oil and gas operators financial and liability risk, performance compared with similar companies, and administrative factors including compliance history with AER requirements. The Holistic Licensee Assessment also includes section 4.5 factors from Directive 067, and other factors as appropriate to assess the capability of licensees to meet regulatory and liability obligations and inform regulatory decisions.
- The **Licensee Management Program**, which was operationalized in 2022, enables the regulator to provide proactive, practical guidance and support to licensees before there is a struggle to manage regulatory and environmental liabilities. Companies are enrolled in the program by the AER after financial or liability risks are assessed.
- The **Inventory Reduction Program** established mandatory annual closure spending quotas for site cleanup that every licensee must adhere to and incentives for additional supplemental closure spending. This

[10] The Government of Canada defines the term "Sustainable Job" as "any job that is compatible with Canada's path to a net-zero emissions and climate resilient future." The term is also intended to reflect "the concept of decent, well-paying, high-quality jobs that can support workers and their families over time and includes such elements as fair income, job security, social protection, and social dialogue."

ensures that sites get cleaned up, provides flexibility for licensees to close sites in a cost effective and efficient manner, and drives consistent economic activity in the oil field and environmental services sectors. The AER required industry to spend $700 million on closure activities in 2023 and for 2024. The industry-wide spending level is set annually and is anticipated to increase by nine per cent every year, with the forecasted target being $992 million in 2027. In January 2024, the AER released the results of the 2022 Closure Quotas in its 2022 Liability Management Performance Report, which showed that industry spent $696 million on closure work and exceeded the $422 million spend quota by 65 per cent.

- The **Closure Nomination Program**, formerly referred to as the 'opt-in mechanism', entered service in April 2023. The program provides a way for landowners, land users, and municipal and Indigenous communities to nominate specific inactive sites for cleanup to the regulator. Licensees are required to provide a rationale for keeping the site; otherwise, they are required to submit a site-closure plan. The AER has considered sites nominated through the Site Rehabilitation Program, and ones that met the eligible requestor and site criteria have transitioned into the Closure Nomination Program. Nominations that have been accepted by the AER are posted on a closure nomination dashboard, which is updated regularly and includes information about the progress of closure activities. In the first year of operations, 1,311 sites have met the criteria for the program and were accepted.
- **Licence transfer** of applications now trigger a holistic licensee assessment for both the transferor and transferee. The assessments support decisions made to deny, close, or approve applications with conditions, including when security is required from either party.
- **Security requirements** were clarified that the AER has broad authority to collect security across the energy development lifecycle as outlined in Section 1.100 of the Oil and Gas Conservation Rules. Under Directive 088, the first phase of the new security framework, security collection was established for the Inventory Reduction Program, Licensee Management Program, and transfer applications.

In March 2023, the Office of the Auditor General (OAG) issued nine recommendations regarding Alberta's liability management system for oil and gas. The AER has assessed the OAG's recommendations and will incorporate them as part of its ongoing implementation of the LMF. This includes developing relevant external performance measures and targets to ensure that Albertans can gauge whether AER's liability management programs are meeting objectives and whether progress is being made.

As of April 2024, there are three remaining foundational pieces of the LMF that need to be developed and implemented:

- Replace the License Liability Rating Program, including the Liability Management Rating, and develop a new security framework to replace the Liability Management Rating security with an approach that:
    - is risk-based, using the holistic licensee assessment described in Directive 088 to determine when and how much security needs to be collected;
    - applies throughout the entire energy development life cycle (application, construction, operation, and closure);

  - implements the Inventory Reduction Program, which aims to increase the amount of closure work occurring in Alberta and reinforces a licensees' regulatory obligation to clean-up and close inactive and abandoned infrastructure;
  - upholds the polluter-pay principle in a way that is fair and manageable; and
  - is financially and administratively feasible for industry.
- Apply the holistic licensee assessment to all oil and gas regulatory decisions. This is currently in place for eligibility and transfer applications; however, it needs to be incorporated into Directive 056 applications and enabled through the information technology system (OneStop) while still maintaining the AER's application timelines.
- Address legacy and post-closure sites.

Taking a proactive approach to liability management throughout the life cycle provides more assurance that companies will be able to meet their regulatory obligations, resulting in fewer sites becoming orphaned.

Orphan Wells

The Orphan Well Association (OWA) has delegated regulatory authority to clean-up wells or sites that do not have a viable or responsible owner. Industry remains liable for these orphan wells. Obligations related to the full closure of oil and gas sites are the responsibility of the company (the licensee) licensed by the Alberta Energy Regulator (AER) to conduct activity on the site. 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.

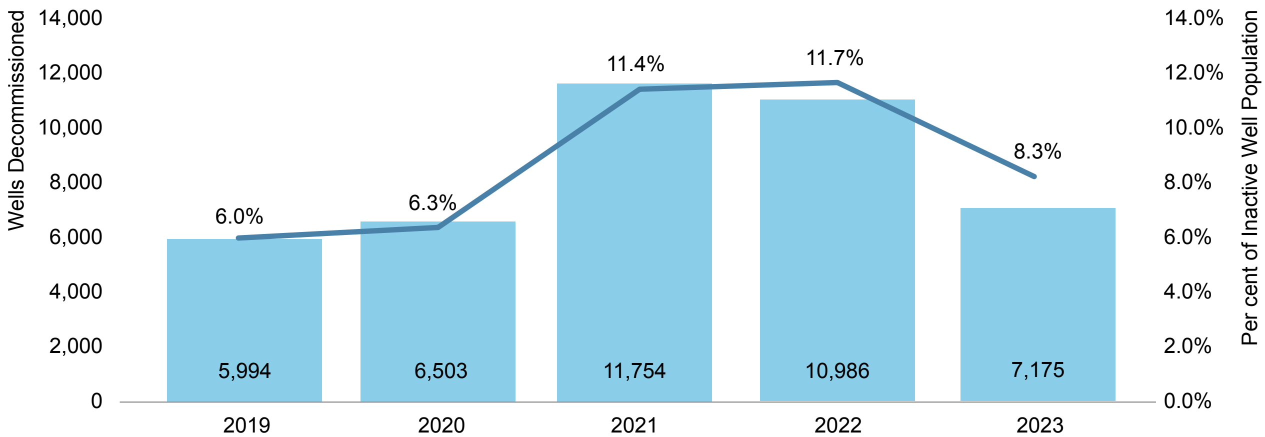
In recent years, the OWA has returned to more typical levels of activity, as the government loans have been utilized and are now being repaid. As of April 2024, the OWA has repaid the Government of Alberta $152 million of the $335 million advanced to accelerate reclamation of orphan well sites. After several years of record-high decommissioning activity, many wells are entering the final stage of the closure process and the OWA is increasingly shifting resources toward reclamation activity. In 2022–23, the OWA received a record number of reclamation certificates, the result of work performed in years prior. The OWA recently used issued authorities to supplement income and decrease costs to the orphan fund, for example:

- The OWA utilized Working Interest Participant Agreement's in cases where it is more cost-effective for the OWA to conduct the closure work than it would be to reimburse a working interest participant for conducting the work.
- The OWA sold salvaged equipment on orphan sites, which generated $11.6 million in revenue that will further support the OWA's clean up work.
- The OWA removed orphaned wells from the orphan inventory via a Regulator Directed Transfer when interested parties wished to obtain a licence for the wells. Regulator Directed Transfers are estimated to have reduced liability and costs to the OWA by almost $8 million in 2022–23.

Annual Wells Decommissioned: Performance Indicator 2.d

Inactive wells are liabilities that operators must properly address to manage their risk exposure. Decommissioning is part of the closure process and involves the company removing surface equipment and sealing the well to prevent the well from affecting the environment. This indicator demonstrates the degree to which industry is moving inactive well inventory through the life cycle toward closure.

Inactive Wells



Source: Alberta Energy Regulator[11]

In 2023, 7,175 wells were decommissioned in Alberta. While this is a decrease from 10,986 in 2022, the total number of wells decommissioned in 2023 remains higher when compared to the years preceding the efforts of the Liability Management Framework (LMF) and the Site Rehabilitation Program (SRP).

The Alberta Energy Regulator (AER) published Directive 088 in December 2021 and has begun implementing the new LMF over the next few years. The LMF introduces several new programs in the oil and gas sector including closure spend quotas. The inventory reduction program sets mandatory industry-wide closure spend requirements. Each licensee has a mandatory closure spend quota which requires them to spend a minimum amount of money on closure work each year. The industry-wide closure spend requirement for 2022 was $422 million. For 2023 and 2024, the AER has increased the industry-wide closure spend requirement to $700 million.

Over the past few years, the SRP has also supported the decommissioning work. The program has contributed to a reduction in Alberta's inactive well population through government subsidization of closure work. The funding for this program ended at the beginning of 2023.

Integrated Resource Management System and Land Use Planning

The development and delivery of Alberta's energy and mineral resources is a major contributor to the province's economic and social well-being, providing revenues, employment, and products that sustain quality of life.

To optimize and sustain these contributions, Alberta must ensure that its energy and mineral resources remain competitive with other jurisdictions and attractive to investment and development. Alberta's investment climate is supported by its tenure and royalty systems, but surety of investment and development also depends on reasonable and timely access to resources. Certainty of access to the land surface is needed by resource developers to make financial decisions and to carry out business activities. If

[11] For more information, see the Performance Measure and Indicator Methodology section of this report on page 79.

access is constrained, development will also be constrained. If access rules are unclear, uncertainty is created for investment.

The Government of Alberta approaches natural-resource management from an integrated systems approach, through which 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.

Land-use planning, which is led by Environment and Protected Areas, is a complex activity that provides opportunities to support the ministry's mandate and presents challenges when developing strategies and outcomes that achieve the desired balance between economic prosperity, social well-being, and environmental protection. For example, it provides a forum for the IRMS ministries to engage in complex conversations about trade-offs, collaborate in the design of policy options, and ensure that existing policies are meeting Albertans' expectations. For industry, land-use plans can also provide policy assurance and surety of access. Policy assurance also takes the form of providing an opportunity to review, assess, revise, and update historic policy direction that may be needed to achieve today's desired outcomes – a core component of the policy cycle and effective resource stewardship.

Developing and implementing land use policies that are clear for all land users and decision makers is a key outcome Energy and Minerals advocates for when participating in planning. The goal is to improve regulatory certainty by clearly defining where or under what conditions energy and mineral resource development can take place at the same time as meeting broader strategic objectives. Achieving positive results requires collaboration, which is why Energy and Minerals takes part in engagement sessions and meetings that give industry stakeholders the opportunity to provide feedback during plan development.

In 2023–24, Energy and Minerals worked collaboratively with cross-ministry partners, external stakeholders, and rights holders to advance the ministry's responsible resource development and stewardship objectives. This includes participating in the development of land-use plans at both the regional and sub-regional scales.

Regional Planning

The Lower Athabasca Regional Plan is currently undergoing a 10-year review as mandated by the *Alberta Land Stewardship Act*. The work is led by the Land Use Secretariat within Environment and Protected Areas. Energy and Minerals submitted its contribution to the review in March 2023. The purpose of the review is to elicit feedback from multiple stakeholders and Indigenous communities and organizations to help government understand the ongoing relevancy and effectiveness of the Lower Athabasca Regional Plan. The South Saskatchewan Regional Plan (SSRP) 10-year review must commence on or before September 1, 2024.

Work occurred in 2023–24 and is ongoing to develop the most appropriate path forward for developing the five remaining plans and renewing approved regional plans to respond to new and evolving challenges and opportunities.

Sub-Regional Planning

In 2023–24, work progressed on six sub-regional plans. The legally binding regulatory details for both the Cold Lake and Bistcho Lake sub-regional plans, which were completed in 2022, are expected to be finalized and released for public engagement in 2024. Completion of the regulatory details will be a significant milestone for the Government of Alberta. The regulatory details are the mechanism by which certain provisions in the sub-regional plans become legally enforceable. They are an important tool for ensuring that these sub-regions will be maintained as working landscapes over the long-term at the same time as they deliver improved environmental outcomes.

The Upper Smoky and Wandering River sub-regional plans were under development in 2023–24 and are expected to be completed in 2024. These plans, like those already in place, will set out management strategies and rules for energy and mineral development, as well as other land uses, to ensure the amount of human footprint on the landscape is maintained at a level that meets the province's objectives for economic and environmental performance. Ongoing engagement among government, the regulators, industry stakeholders, and other rights and interest holders will help ensure that the strategies and rules set out in the plans will be both efficient and effective and positively contribute to Alberta's business climate.

The sustained efforts that external stakeholders and rights holders put into engaging with government through the sub-regional task forces and working groups active in 2023–24 reinforced the value of engaging broadly and openly in matters pertaining to integrated resource management. It also demonstrates the Government of Alberta's commitment to the principles of Integrated Resource Management System—improved information sharing and collaboration and better transparency and integration—particularly where there could be conflict between user groups and interest holders. The advice and recommendations provided through the sub-regional planning forums help government design and implement effective policies that not only consider existing interests in the land, like oil and gas and oil sands extraction, but also new resources and technologies, like carbon capture, utilization and storage and minerals, that are also strategic priorities for Energy and Minerals.

Unpaid Municipal Taxes

To complement the new liability management framework, the Government of Alberta took action to address unpaid taxes owed to municipalities.

In March 2023, the Government of Alberta issued a ministerial order under the *Responsible Energy Development Act*, which requires the Alberta Energy Regulator (AER) to receive evidence that municipal taxes have been paid when approving well license transfers or new well licenses. The AER implemented the ministerial order, and as of May 1, 2023, companies that apply for the transfers or new licenses must provide evidence that unpaid municipal taxes have been resolved for amounts over $20,000. Preliminary evaluation of this program indicates that companies still in operation are being incentivized to pay their share of property taxes in order to continue to operate. Several municipalities have been able to recover unpaid property taxes from companies, either by full payment of unpaid taxes, or by entering into repayment agreements. AER has needed to build capacity and processes to implement the ministerial order, as well as coordinate with government on municipal data and company data. Work continues in the first year of implementation to develop efficient processes.

2.3 Optimize regulation and oversight of Alberta's energy and mineral sector to responsibly utilize and develop resource potential, while enhancing sector competitiveness

Red Tape Reduction at the Alberta Energy Regulator

Between 2019 and 2024, the Alberta Energy Regulator (AER) has undertaken a significant amount of work in reviewing its regulatory instruments, making regulatory count reductions, and delivering initiatives with substantial industry cost savings ($1.68 billion).

In 2023–24, the AER continued to reduce its regulatory count by:

- Revising 50 regulatory instruments during 2023–24;
- Removing 9,154 total requirements, or 22.2 per cent off the baseline, since April 1, 2019;
- Adding 3,880 regulatory requirements to clarify new rules for resource development, such as minerals and geothermal; and
- Achieving cumulative NET reduction of 5,279 requirements, or 12.8 per cent off the baseline, since April 1, 2019.

In completing this work, the AER ensured that the environment was protected, and public safety was maintained, while also carrying out stakeholder and public engagement on any changes that were significant and impactful to stakeholders and rights holders.

The AER's efforts focused on identifying and reducing obsolete or redundant requirements. Regulated parties will be better able to navigate the revised regulatory instruments and understand the requirements. The AER completed projects that also have material cost savings to industry.

Efficiencies include:

- The AER completed updates to Directive 023: Oil Sands Project Applications, providing clarity of processes and removal of over 670 requirements.
- Published a new edition of the Pipeline Rules that modernized requirements for the lifecycle of pipeline activities and enhanced functionality for the filing of pipeline applications in OneStop.
- In association with the Pipeline Rules, the AER made changes to Pipelines Requirements and Reference Tools under Directive 077: Pipelines—Requirements and Reference Tools, allowing for the use of temporary surface pipelines for water conveyance in support of the Government of Alberta's Water Conservation Policy for Upstream Oil and Gas Operations.
- Updates to Survey and Mapping Standards completed by both the AER and Alberta Parks and Recreation resulted in replacing costly surveyed boundary plans with more affordable sketch plans for many parks and public lands dispositions.
- Updating the Well Abandonment Requirements in the AER's Directive 020, which created $15.8 million in annual savings for industry.
- The AER created new directives for hard rock-hosted minerals to provide environmental protections and increase regulatory certainty for investment and job creation in these industries.
- The expansion of the AER's mandate, which includes new mineral resources and liability management initiatives, creates some challenges to implement all the regulatory efficiency initiatives within target timelines. Energy and Mineral and the AER continue to collaborate at all levels. This includes staff-level working sessions and well-established processes, such as the various Integrated Resource

Management System committees, the Joint Working Group and its subcommittees, and the Red Tape Reduction Oil and Gas Panel.

Industry Performance Program

The AER's Industry Performance Program measures, evaluates, reports, and monitors the energy industry's performance in Alberta. Under the program, the AER publishes performance reports about pipeline incidents, water use, methane emissions, and most recently liability management, to provide Albertans with information regarding energy-development activities and how the AER works to protect public safety and the environment.

Pipeline performance report: The pipeline performance report provides Albertans with information about 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 AER evaluates all pipeline failures to understand the causes and to assess compliance with rules. The AER uses what it learns to educate companies, either during pipeline inspections or, for example, by publishing bulletins.

The AER ensures pipeline operators act responsibly, prioritizing public safety and the environment.

In 2022, there were about 40 per cent fewer incidents than in 2013, even though the total pipeline kilometres grew by 8 per cent in the same period. This translates to an incident rate of 0.73 per 1,000 kilometres of pipeline compared with 1.32 per kilometres in 2013. The number of pipeline incidents rated as a high consequence dropped by 27 per cent, decreasing from 11 incidents in 2021 to eight incidents in 2022.

Findings from the pipeline performance report helped develop requirements for the Pipeline Rules modernization project, which came into force November 15, 2023.

Water use performance report: The AER's water-use performance report highlights how water is allocated and used to produce oil, gas, and oil sands resources. In 2022, companies used less non-saline water (lake or river water, groundwater, or surface runoff water) than what is allocated to them. Only 13 per cent of non-saline water allocated to all industries in the province was allocated for oil and gas development, and the industry used 21 per cent of its allocation, which is a slight increase from 19 per cent in 2021. Of the water used by the oil and gas industry, 17 per cent was non-saline, and one per cent was alternative make-up water (saline groundwater, wastewater, or water recycled from hydraulic fracturing operations). The remaining 82 per cent of the water used for energy development was recycled. Non-saline water-use intensity across the energy industry has decreased by 21.6 per cent since 2013.

Methane performance report: The AER's latest methane performance report shows that the province achieved the 45 per cent reduction goal in 2022, three years early, by implementing an Alberta-tailored policy approach that combines regulatory requirements, market-based mechanisms, and program supports.

Liability management performance report: The liability management performance report tracks the industry's performance relating to liability management and the impact of its requirements over time. The report improves transparency about industry's management of conventional oil and gas liabilities and develops performance-measure baselines and ongoing assessments of industry as a whole and licensees specifically.

Between 2002 and 2010, there was significant growth in active wells with over double in 2010 (just over 100,000 in 2002 and almost 200,000 in 2010) due to drilling activity. As the number of active wells levelled off and began to decline, the number of inactive wells in the province continued to grow at 5 per cent annually between 2000 and 2020, with under 50,000 wells in 2000 and under 100,000 wells in 2020.

With the ongoing implementation of the Liability Management Framework, specifically the industry-wide closure quotas, positive progress towards closure is being made. In 2022, industry surpassed its $422 million requirement by 65 per cent, spending $696 million. Considering all closure activity (including the Orphan Well Association and the government-funded Site Rehabilitation Program grants), more than $1.2 billion was spent on closure in 2022. This reduced the number of inactive wells by 9 per cent, and it increased the number of decommissioned and reclaimed certified wells by 10 per cent and 5 per cent, respectively.

In 2022, 90 per cent of companies complied with their closure spend quotas. Of the 10 per cent of companies that were non-compliant; the outstanding missed closure spend was $4.2 million, or one per cent of the industry total.

Regulatory Compliance: Performance Indicator 2.b

The Alberta Energy Regulator (AER) tracks the percentage 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.

	2019–20	2020–21	2021–22	2022–23	2023–24
Compliant Inspections: Per cent of inspections in compliance with regulatory requirements	78	79	75	73	72

Source: Alberta Energy Regulator[12]

In 2023–24, the AER conducted 9,518 field inspections and resulted in 6,876 resulting in a finding of compliance.

While 15 percent more inspections were completed in 2023–24 in comparison to 2022–23, more sites with non-compliances were found. This has resulted in a decrease in compliance rates, which now sit at 72 per cent. This means that industry was required to address more issues in the field. Specifically, 2,642 sites with non-compliances were found and addressed in 2023–24 whereas 2,200 sites with non-compliances were found and addressed in 2022–23. Non-compliances can range in severity, such as not calibrating volume measurement equipment to releasing a toxic substance into the environment. The change in compliance rate is a result of a combination of factors, which include increased industry activity and internal process improvements, which leverage our field inspectors' expertise with organizational data to ensure we adjust throughout the year and have oversight on the energy development activities where it is most needed.

Pipeline Safety: Performance Indicator 2.c

The Alberta Energy Regulator (AER) conducts construction and operational inspections, to ensure operators comply with pipeline regulations to safely operate and prevent incidents. To prevent pipeline incidents from occurring, the AER inspections focus on preventative pipeline maintenance programs, leak detection, hydrotechnical and geotechnical programs and inactive pipelines. When a pipeline incident does occur, all

[12] For more information, see the Performance Measure and Indicator Methodology section of this report on page 79.

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.

	2018	2019	2020	2021	2022	2023
Number of High Consequence Pipeline Incidents	24	20	16	11	8	7

Source: Alberta Energy Regulator[13]

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

High consequence pipeline incidents decreased slightly, from 8 incidents in 2022 to 7 in 2023 accounting for only two per cent of total pipeline incidents. In 2023, there were about 46 per cent fewer total incidents than in 2014, even though the total pipeline kilometres grew by 7 per cent in the same period.

The AER takes the following actions to improve pipeline performance:

- conducts inspections during pipeline construction to verify proper practices are being used;
- educates operators about our requirements, industry best practices, and emerging issues;
- reviews every pipeline incident to verify if a company correctly determined the cause and if they followed our pipeline requirements (i.e. compliance);
- investigates every pipeline incident to understand its cause to improve performance and prevent future incidents; and
- identifies areas for improvement in each company's safety and loss management system and pipeline integrity management programs.

Indigenous Engagement at the Alberta Energy Regulator

The Alberta Energy Regulator (AER) is always seeking opportunities to improve how it engages with Indigenous communities and considers their values, interests, and concerns. A foundation of the AER's approach is the book "Voices of Understanding", which was co-authored in 2017 with Dr. Reg Crowshoe, an Indigenous Elder, and AER staff. The AER's 2022–25 Strategic Plan identified the creation of an Indigenous Relations plan and has since worked on understanding Indigenous worldviews and considering the risk of harm to Aboriginal rights, treaty rights, and Indigenous interests when making regulatory and corporate decisions.

In 2023–24, AER supported this work by:

- hosting an Elders Circle intended to expand the AER's relationships with Indigenous communities, obtain consistent guidance on our interactions with Indigenous peoples, and demonstrate how oral and written systems can work together;
- implementing initiatives within the AER's Indigenous Relations Plan, identifying formal and experiential learning opportunities, and exploring Indigenous inter-cultural competencies for employees;
- increasing executive engagement with Indigenous leaders, First Nation and Métis community leaders, and Indigenous organizations;

[13] For more information, see the Performance Measure and Indicator Methodology section of this report on page 79.

- enhancing AER's relationship with the Indigenous Resources Council and Indian Oil and Gas Canada through Memorandum of Understandings;
- engaging Indigenous communities on the development of the regulatory framework for rock-hosted minerals and Directive 071, Emergency Preparedness and Response; and
- continuing to create opportunities for First Nations and Metis Settlements to participate in joint compliance inspections on their lands.

This work is intended to support informed decision making, demonstrate AER's responsible approach to energy development and help strengthen relationships and mutual understanding with Indigenous peoples and their interactions with energy development.

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 Alberta Energy Regulator (AER) regulates 243 dams across the province, including 132 tailings dams, the majority of which are in the oil sands mining sector dams operated by energy companies. Overtime, the number of dams increase due to new projects, additional fluid needs at existing projects and re-evaluation of existing structures meeting the criteria of regulated dams.

In 2023, the AER released the 2022 AER Dam Safety Program Report, which is available on www.aer.ca.

Fluid Tailings Management

The Alberta Energy Regulator (AER) regulates tailings in Alberta's mineable oil sands in accordance with all requirements set under the Government of Alberta's Tailings Management Framework for the Mineable Athabasca Oil Sands (TMF) and the AER's Directive 085: Fluid Tailings Management for Oil Sands Mining Projects (Directive 085). The TMF requires companies to progressively treat their tailings with a technology approved by the AER, so that they are ready to reclaim within 10 years after mining has stopped. The AER has approved tailings management plans for each oil sands mine, which list the actions companies will take over the next several decades to meet this objective in the TMF.

Under Directive 085, the AER reports annually on the amount of tailings produced at each oil sands mine and the technologies that companies are using to treat their tailings. In 2023, the AER released the 2022 State of Fluid Tailings Management for Mineable Oil Sands Report, which is available on www.aer.ca.

An Environmental Protection Order was issued in February 2023 by the AER to Imperial Oil in response to two separate wastewater release incidents at the Kearl Oil Sands Project. The Environmental Protection Order remains in effect. To ensure compliance with the order, AER subject-matter experts continue to review reports and submissions provided by Imperial and inspect the Kearl site weekly to oversee the company's response efforts.

As part of the AER's response to incidents at Imperial's Kearl Oil Sands Project, the AER's top priority is to ensure the safety of the public and the environment and that any potential impacts to the public and Indigenous groups are prevented or mitigated and communicated transparently. Since April 2023, the AER has been providing weekly updates through email to community representatives and posting them online.

Seismicity

The Alberta Energy Regulator (AER), through the Alberta Geological Survey (AGS) uses a network of over 50 monitoring stations across the province to measure and research seismic activity across Alberta. This information is used by AGS to form an accurate picture of earthquake locations, magnitudes and to determine the cause of these events, which are publicly reported on the Alberta Earthquake Dashboard. Alberta experiences natural and induced seismic events, most of which are not felt due to low intensity and ground conditions. To date, the AER is not aware of any damage that has been caused by seismic events in Alberta.

In Alberta, human activities that can cause induced earthquakes include:

- the extraction of fluids,
- geothermal operations,
- wastewater disposal,
- the impoundment of dams,
- subsurface storage using carbon capture utilization and storage technology, and
- hydraulic fracturing.

In areas where earthquakes have been induced from energy development in the past, the AER has issued orders to operators to limit the hazard of induced seismic activity. In addition, in areas of the province where the likelihood of an induced earthquake is higher, the AER has developed monitoring and reporting requirements that companies conducting hydraulic fracturing must follow. If companies fail to meet AER requirements, compliance and enforcement tools are available to bring operators back into compliance.

In 2023–24, the AER and AGS:

- applied and upheld subsurface orders in areas of the province that are more susceptible to induced earthquakes.
- produced annual seismic hazard analysis maps that provide the public with additional information on ground shaking from earthquakes in the province in the previous year and a forecast of potential ground shaking in the upcoming year.
- added 14 additional seismic stations to the AGS network in 2024 and continued to update webpages on www.aer.ca and https://ags.aer.ca to provide the public with additional information on induced seismicity.
- received data from over 100 seismic stations operated by eight seismic monitoring networks in Canada and the United States to evaluate seismic activity in Alberta.

The AER and AGS are exploring ways to embed requirements to limit the risk of induced seismicity as it relates to new industries regulated by the AER, including brine-hosted minerals and geothermal.

Accelerating Alberta Energy Regulator Application Processes

Since 2015, the Alberta Energy Regulator (AER) has aimed to improve its regulatory system by streamlining the application process, shortening review timelines, and enabling robust life-cycle oversight of a project's risks. As a result, the AER is making better regulatory decisions faster, and with less cost for industry, while providing Albertans with better access to information and oversight of the energy-development life cycle.

The AER's journey has been led by the implementation of the Integrated Decision Approach supported by the technology solution, OneStop. OneStop uses a complex set of rules to automate routine (low risk) applications and forward non-routine (high risk and more complex) applications to technical experts for review.

In 2019, the AER reduced its application timelines by 50 per cent, and performance targets for meeting timelines for routine and non-routine applications were developed. Since then, the AER has consistently achieved both the 99 per cent target for routine applications and 95 per cent target for non-routine applications.

Of the applications the AER receives, about 75 per cent (over 25,000 applications annually) are processed through OneStop. The remaining 25 per cent of applications that AER receives outside of OneStop (e.g. email, legacy systems, etc.) are manually reviewed. All applications to the AER follow a consistent, risk-informed process. Of the applications processed through OneStop, over 50 per cent are low risk and are fully automated, providing application decisions in minutes. On average, the AER receives about 37,000 applications each year.

The AER uses a structured-review tool (SRT) to make its risk-informed decision process more efficient and effective. The SRT captures non-routine application review analysis and comments. Additionally, the SRT:

- enables efficient, effective risk-informed regulatory decisions by focusing on what matters (e.g. application review is focused on high risks).
- increases regulatory decision certainty following consistent, repeatable, defensible methods.
- enables efficient data analysis and reporting for improved transparency and information sharing.
- identifies opportunities for continuous improvement of processes, requirements, and systems.

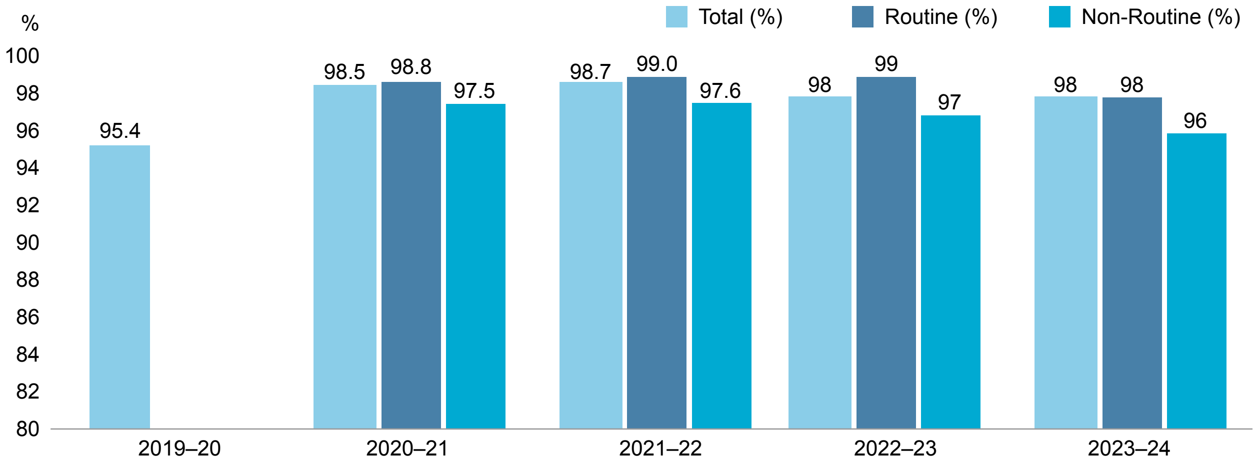
The AER is currently developing new technology to support the structured review for applications that will replace the existing SRT. This new technology will improve administrative efficiency through better usability for AER staff and enable enhanced data collection to drive further process improvements through data analysis.

The AER has invested about $60 million to develop OneStop, resulting in $542 million of verified industry savings to date through process efficiencies.

The AER continues to identify and implement process efficiencies and use risk-informed decision-making and technology to reduce manual interactions with systems and build efficiencies. The AER constantly reassesses risk to ensure resources are focused on areas of highest or unknown risk.

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

Target: The target for applications meeting turnaround targets for 2023–24 is 99 per cent for routine applications and 95 per cent for non-routine applications.



Sources: Alberta Energy Regulator[14, 15]

Discussion of Results

The measure indicates the Alberta Energy Regulator's (AER's) efficiency in application processing timelines, drives internal performance and provides certainty and transparency to the public related to AER turnaround targets. Every application process receives a turnaround target at the time of application receipt that considers the complexity the application represents. Applications that are deemed a higher, or uncertain risk, are considered non-routine and require additional review. The measure was created to help measure the overall efficiency of the AER's application processing, drive internal performance, and provide certainty and transparency. Overall, 98 per cent of all applications met turnaround targets in 2023–24.

The number of applications received by the AER in 2023–24, were 34,768, which remained comparable to the 36,552 applications that were received in 2022–23. Not all applications received were processed prior to the end of the fiscal year; this could be due to reasons such as complex applications requiring more time, or applications that were received shortly before the deadline for reporting. Of the 34,744 applications processed in 2023–24, there were 21,389 routine applications and 13,355 non-routine applications. In this most recent fiscal year, the AER experienced an increased volume of non-routine applications due to a rise in industry activity, and system enhancements resulted in more non-routine being correctly categorized. In 2023–24, 98 per cent of AER routine applications met turnaround targets. The AER exceeded the non-routine target by processing 96 per cent of those applications within target timelines. This performance can be attributed to the ongoing implementation of the AER's Integrated Decision Approach and improvements made to automate low-risk application types in AER systems 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.

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

[14] Note: Further information about the sources and methodology for this performance indicator can be found in the Performance Measure and Indicator Methodology section on page 79.

[15] Note: Results for 2022–23 and 2023–24 in this annual report were rounded to the nearest whole number to align with the targets set out in the 2023–26 Energy and Minerals Business Plan. Results in the 2022–23 Energy and Minerals Annual Report were also rounded to align with the targets set out in the 2022–25 Energy and Minerals Business Plan, with exception to the total per cent of applications meeting turnaround targets, which was rounded to the first decimal place due to an administrative error. This has been corrected in the 2023–24 Energy and Minerals Annual Report.

Energy and Minerals Highlights Table

		2022–23	2023–24
Bitumen	Revenue	$16.9 billion	$14.5 billion
	Bitumen wells drilled (1)	3,580 (2022)	4,096 (2023)
	Total bitumen production in barrels per day (bbl/d)	3.32 million bbl/d (2022)	3.41 million bbl/d (2023)
	Marketable bitumen and Synthetic Crude Oil production	3.12 million bbl/d (2022)	3.24 million bbl/d (2023)
Conventional Crude Oil	Revenue	$3.97 billion	$2.97 billion
	Average price for West Texas Intermediate (WTI)	US$89.69/bbl	US$77.83/bbl
	Conventional crude oil production	0.49 million bbl/d (2022)	0.52 million bbp/d (2023)
	Pentanes and condensate production	0.37 million bbl/d (2022)	0.37 million bbl/d (2023)
	Crude oil wells drilled (1)	3,653 (2022)	2,869 (2023)
Total Crude and Equivalent	Production (conventional, marketable bitumen and Synthetic Crude Oil, pentanes plus and condensates)	3.98 million bbl/d (2022)	4.12 million bbl/d (2023)
	Removals from Alberta	3.86 million bbl/d (2022)	3.99 million bbl/d (2023)
	% of total crude oil and equivalent disposition	87% (2022)	88% (2023)
Natural Gas and By-Products	Revenue	$3.60 billion	$1.06 billion
	Average Alberta Gas Reference Price (ARP)	$4.63/GJ	$2.07/GJ
	Number of conventional natural gas wells drilled (1)	956 (2022)	969 (2023)
	Total marketable natural gas production including Coalbed Methane	3.76 Tcf (2022)	3.81 Tcf (2023)
	Coalbed Methane production	0.16 Tcf (2022)	0.15 Tcf (2023)
	Total natural gas deliveries	5.51 Tcf (2022)	5.40 Tcf (2023)
	* To the United States	32%	31%
	* Within Alberta	39%	39%
	* To rest of Canada	29%	30%
Bonuses and Sales of Crown Leases	Revenue from bonuses and sales of Crown leases	$0.46 billion	$0.50 billion
	Revenue from rentals and fees	$0.19 billion	$0.15 billion
	Average price per hectare (ha) paid at petroleum and natural gas rights sales (2)	$579.50	$481.31
	Petroleum and natural gas hectares sold at auction (2)	658,494.09 ha	781,725.31 ha
	Average price per hectare paid for oil sands mineral rights (2)	$700.86	$1,058.91
	Oil sands hectares sold at auction	100,585.31	106,472.12
Freehold Mineral Tax	Revenue	$161 million	$125 million

		2022–23	2023–24
Wells and Licences	Well Licenses issued	7,639 (2022)	7,177 (2023)
	Industry drilling (3)	8,863 (2022)	8,829 (2023)
Coal	Revenue	$146 million	$92 million
	Established coal reserves (estimate)	33.1 billion tonnes	33.1 billion tonnes
	Raw coal production	20.1 million tonnes (2022)	17.55 million tonnes (2023)
	Total marketable coal deliveries	13.4 million tonnes (2022)	11.5 million tonnes (2023)
	Percentage of total coal deliveries exported out of province	65.6% (2022)	73% (2023)
Metallic and Industrial Minerals	Metallic and Industrial minerals Royalty Revenues (4)	$599,778.89	$468,423.35
	Hectares of mineral permits issued to exploration companies (Land Automated Mineral Agreement System, Metallic and Industrial Minerals Permits and New Application Issued)	2,413,404.00	94,247.00
Upstream Energy Sector Employment		138 thousand (2022)	134 thousand (2023)
Upstream Energy Sector Investment (5)		$28 billion (2022)	Estimated $29 billion (2023)

Notes to 2023–24 Annual Report:

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

(2) Data result has been retroactively adjusted to reflect the updates that took place since the publication of the previous Annual Report. Excluded from these figures are direct sales which comprise of fractional land, complementing rights or single substance leases. These sales are initiated by the purchaser and are therefore not predictable in nature.

(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) Additional production was reported for the 2022/23 fiscal year after the publication of last year's report.

(5) Data result for 2022 has been retroactively adjusted to reflect the updates that took place since the publication of the previous Annual Report.

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 and Minerals 2023–26 Business Plan: Albertans benefit from investment in responsible energy and mineral development and access to global markets.

Royalty programs exist for several 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 each 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.
- The royalty programs under the Modernized Royalty Framework are reported on a fiscal year basis to align with government reporting as a whole.
- To improve accuracy, reporting is delayed by one year to better reflect industry amendments.
- 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 and Minerals 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 substances 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 2022–23 fiscal year, the Enhanced Hydrocarbon Recovery Program received eight applications in comparison to nine applications in the 2021–22 fiscal year. The overall trend for program uptake has been relatively steady since the first year of the program's inception. Since the program's inception in 2017, 52 applications were received from 27 companies, of which 23 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 2022–23 fiscal year.
- One application 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 2022–23 fiscal year.

	2018–19	2019–20	2020–21	2021–22	2022–23	Total
Number of Applications Received	12	9	3	9	8	52
Number of Different Companies Submitting Applications[16]	11	7	3	7	5	27
Number of Applications Approved	4	7	6	2	4	23
Number of Applications Denied	11	4	1	3	0	19
Number of Applications Withdrawn[17]	1	0	1	0	0	2
Applications to be Processed at the end of 2022–23 Fiscal Year						8

Note: Application approval/denial/withdrawal are counted in the year a decision is made, not in the year of receipt of application. The numbers in the table do not add up horizontally, as only 5 years data are included in the table.

The active enhanced recovery schemes in the program generated a total Crown production of 179,383 cubic metres of oil, and 599,652,500 cubic metres of gas in 2022–23. In comparison, active enhanced recovery schemes generated a total Crown production of 187,208 cubic metres of oil, and 424,895,200 cubic metres of gas in 2021–22, a year-over-year decrease of 4.2 per cent for oil and an increase of 41.1 per cent for gas. The decrease in oil can be attributed to more recovery schemes terminating from the program benefit period than schemes commencing in the program. The increase in gas can be attributed to higher commodity prices influencing decisions to increase production.

[16] Due to an administrative error in the 2022–23 Annual Report, the Number of Different Companies Submitting Applications in 2021–22 was previously reported as eight. This has been corrected to seven in the current 2023–24 Annual Report.

[17] Due to an administrative error in the 2022–23 Annual Report, the Number of Applications Withdrawn in 2020–21 was previously reported as zero. This has been corrected to one in the current 2023–24 Annual Report.

Total Crown royalty volumes from the approved enhanced recovery schemes totalled 8,972 cubic metres of oil, 5,192 cubic metres of natural gas liquids and 24,188,600 cubic metres of gas, which translates to about $8.7 million in total royalty revenue in 2022–23, an increase of 24.2 per cent from 2021–22.

	2019–20	2020–21	2021–22	2022–23
Total Crown Royalty Volumes–Oil (m^3)	5,195	6,448	10,014	**8,972**
Total Crown Royalty Volumes–NGL (m^3)	2,347	2,967	4,252	**5,192**
Total Crown Royalty Volumes–Gas (10^3m^3)	15,275	14,570	21,327	**24,189**
Total Crown Royalty Revenue ($)	3,114,633	3,112,904	6,963,606	**8,650,985**

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 high-risk and high-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 2022–23 fiscal year, the Emerging Resources Program received no applications due to cost inflation increasing development costs of new high-cost projects and discouraging investment. Emerging resources projects are expensive and require significant capital investment to develop. Since the program was launched, 24 applications have been received from 15 companies. Eight applications were approved, 15 applications were denied, one was withdrawn, and none were under review at the end of the 2022–23 fiscal year.

	2018–19	2019–20	2020–21	2021–22	2022–23	Total
Number of Applications Received	6	4	2	1	0	24
Number of Different Companies Submitting Applications	5	4	1	1	0	15
Number of Applications Approved	3	3	0	0	1	8
Number of Applications Denied	1	5	4	1	0	15
Number of Applications Withdrawn	1	0	0	0	0	1
Applications to be Processed at the end of 2022–23 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 numbers in the table do not add up horizontally, as only 5 years data are included in the table.

The cumulative number of potential new project wells participating in the program in 2022–23 was 4,654. The number of new project wells increased by 574 in 2022–23, as one new application was approved.

	2018–19	2019–20	2020–21	2021–22	2022–23
Number of New Project Wells	2,190	1,124	0	0	574
Cumulative Number of Project Wells	2,956	4,080	4,080	4,080	4,654

Approved projects in the program generated a total Crown production of 415,970 cubic metres of oil, 9,302 cubic metres of condensate, and 2,178,493,600 cubic metres of gas in 2022–23. Increased oil production can be attributed to new project wells starting to produce. Of the eight approved projects, six are active with producing project wells.

Total Crown royalty volumes from Emerging Resources Program projects totalled 20,800 cubic metres of oil, 64,850 cubic metres of natural gas liquids, 465 cubic metres of condensate, and 97,184,200 cubic metres of gas. This translates to about $71.4 million in total royalty revenue in 2022–23 from approved Emerging Resource Program projects, a 15 per cent increase from 2021–22; 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.

	2019–20	2020–21	2021–22	2022–23
Total Crown Royalty Volumes–Oil (m^3)	7,246	15,289	15,425	20,800
Total Crown Royalty Volumes–NGL (m^3)	37,126	82,577	81,606	64,850
Total Crown Royalty Volumes–Condensate (m^3)	1,242	1,109	619	465
Total Crown Royalty Volumes–Gas (10^3m^3)	34,120	83,788	101,103	97,184
Total Crown Royalty Revenue ($)	17,068,405	33,911,792	62,286,027	71,431,373

Alberta Royalty Framework's Royalty Programs

A number of royalty programs under the Alberta Royalty Framework stopped accepting new entrants in 2017 and most have been phased out once their related regulations expired. There is one royalty program left under the Alberta Royalty Framework that will be phased out in 2026, the Enhanced Oil Recovery Program. The ministry will continue to monitor and report on the progress of this program until it officially expires.

Enhanced Oil Recovery Program

The Enhanced Oil Recovery Program was implemented in 2014 and has been making progress towards achieving its intended outcomes, including encouraging incremental crude oil production through enhanced oil recovery (EOR) methods, which 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.

Total Crown production from EOR in 2022 was 367,437 cubic metres, which is a decrease of 18,509 cubic metres from the previous year. The Crown royalty volumes from active EOR schemes totalled to 81,887 cubic metres, which translates to approximately $57.7 million in total royalty revenue in 2022. The total royalty revenue increased by over $31.2 million in 2022 from approximately $26.5 million reported in 2021.

The increase in royalty revenue can be explained by a combination of factors. The royalty revenue increase was driven by the West Texas Intermediate (WTI) price increase impact outweighing the decrease in total crown production from EOR. The WTI price increased from around US$68/bbl in 2021 to US$95/bbl in 2022, leading to higher royalty rates and higher royalty revenue per Crown royalty cubic metres. This impact far outweighed the Crown production from EOR decrease from 2021 to 2022 which was due to economic shut-ins, wells reaching maturity, and schemes terminating after reaching their benefit periods. Of the total royalty revenue of $57.7 million, approximately $57.5 million was considered incremental royalty to the Crown that would not have been generated without the program. The incremental royalty revenue has increased by approximately $31.1 million in 2022.

	2018	2019	2020	2021	2022
Total Crown production from EOR	642,834m^3	502,289m^3	405,962m^3	385,946m^3	367,437m^3
Total Crown royalty volumes from EOR	103,891m^3	69,605m^3	39,121m^3	59,188m^3	81,887m^3
Total Crown royalty revenue from EOR	$44.6 million	$27.2 million	$12.6 million	$26.5 million	$57.7 million
Incremental Crown royalty revenue from EOR	$41.6 million	$27.0 million	$12.5 million	$26.4 million	$57.5 million

Without the program support, EOR schemes are generally uneconomic and unattractive to investors because of 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.

Performance Measure and Indicator Methodology

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

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:

$$\frac{\textit{Annual Barrels of Alberta Oil Sands Production}}{\textit{Barrels of World Oil Consumption}}$$

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 the 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

Alberta's crude oil and equivalent production portion of the indicator consists of production volume (millions of barrels/day), and crude oil and equivalent leaving Alberta (in percentage).

The indicator reports the volume of Alberta's annual crude oil and equivalent production, as well as the total percentage of crude oil disposition leaving Alberta.

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 Alberta Energy Regulator (AER) reports. Alberta's Energy Resource Sector section in the Annual Report provides an overview of crude oil and equivalent production. There were no changes in the presentation of crude oil and equivalent production results from the 2022–25 Business Plan to the 2023–26 Business Plan, on which the present, 2023–24 Annual Report is based. The units in the future Annual Reports may be adjusted, as required. Changes in the units do not reflect any methodology changes.

However, the present Annual Report also includes an adjustment that was made to the indicator in the 2024–27 Business Plan. The indicator now also includes the portion, which reports total percentage of crude oil disposition leaving Alberta. This portion of the indicator was previously reported in the 2020–23 Business Plan, but did not appear in the subsequent business plans, until the 2024–27 Business Plan. For this portion of the indicator, Energy and Minerals reports the share of total crude oil leaving Alberta as a percentage of total calculated disposition. All data for this portion of the indicator is also taken from the AER reports. To enhance reporting, this portion of the indicator was included in the present, 2023–24 Annual Report, rather than being included in the future, 2024–25 Annual Report, which will be directly linked to the 2024–27 Business Plan.

The total natural gas production portion of the indicator consists of marketable production volume (billion cubic feet/day), and natural gas leaving Alberta (in percentage).

The indicator reports the volume of Alberta's marketable natural gas production, as well as the total percentage of natural gas disposition leaving Alberta.

All results for this component of the indicator are calculated from the AER reports. Alberta's Energy Resource Sector section provides an overview of marketable natural gas production in Alberta.

There were no changes in the presentation of marketable natural gas production results from the 2022–25 Business Plan to the 2023–26 Business Plan, on which the present, 2023–24 Annual Report is based. The units in the future Annual Reports may be adjusted, as required. Changes in the units do not reflect any methodology changes.

As in the case with the oil portion of the indicator, the present Annual Report also includes an adjustment for natural gas that was made to the indicator in the 2024–27 Business Plan. The indicator now also includes the portion, which reports total percentage of natural gas disposition leaving Alberta. This portion of the indicator was previously reported in the 2020–23 Business Plan, but did not appear in the subsequent business plans, until the 2024–27 Business Plan. For this portion of the indicator, Energy and Minerals reports the share of total natural gas leaving Alberta as a percentage of total calculated disposition. All data for this portion of the indicator is taken from the AER reports. To enhance reporting, this portion of the indicator was included in the present, 2023–24 Annual Report, rather than being included in the future, 2024–25 Annual Report, which will be directly linked to the 2024–27 Business Plan.

Overall, the adjustments in the indicator were consistent for the oil and gas portions of the indicator, as both portions now include disposition components.

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.

There were no changes in the presentation of upstream Alberta investment results from the 2022–25 Business Plan to the 2023–26 Business Plan, on which the present, 2023–24 Annual Report is based. The units in the Annual Report may be adjusted, as required. Changes in the units do not reflect any methodology changes.

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

This portion of the indicator focuses on the investment impacts of the downstream activity and 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 is 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.

Data for the Downstream portion of the indicator is also taken from Statistics Canada. Data is reported on a calendar year basis.

There were no changes in the presentation of downstream Alberta investment results from the 2022–25 Business Plan to the 2023–26 Business Plan, on which the present, 2023–24 Annual Report is based. The units in the Annual Report may be adjusted, as required. Changes in the units do not reflect any methodology changes.

In addition to actual results, both the Upstream and Downstream components of the 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.

Both portions of the indicator include the investment amounts in Canadian dollars, in the upstream and downstream portions of Alberta's energy industry. The Annual Report also reports the shares of Canadian investment; however, these shares are included as supplemental information, and are not a formal part of the indicator.

Source: Statistics Canada.

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

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–Onestop is the application workflow system developed and implemented to support AER applications, pipelines applications, *Water Act* approvals, land use applications, new well applications, and reclamation certificates are processed through OneStop.
- 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.

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.

Source: Alberta Energy Regulator.

**Performance Indicator 2.b:
Regulatory Compliance (Alberta Energy Regulator)**

The data source is the Field Inspection System (FIS). A .SQL script pulls the results for this indicator and 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 mining industries. The inspection findings and outcomes are recorded in the FIS database. Geophysical inspections are not included in the FIS 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, week 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-compliance with suspensions and administrative sanctions were included, however, they have been removed as they can occur without an investigation. Therefore, they are not truly a type of field enforcement action.

2023–24 data was retrieved on April 12, 2024. The reported numbers include closed, amended and reconsidered enforcement decisions.

Source: Alberta Energy Regulator.

**Performance Indicator 2.c:
Pipeline Safety (Alberta Energy Regulator)**

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 Field Inspection System 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.

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 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 to 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.

Source: Alberta Energy Regulator.

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

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 as 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 abandoned date. Note that if a well has multiple abandonment records in multiple years, these are counted within each year.

Date 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

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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 that make 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, 2024

	2024		2023	Change from	
	Budget	Actual	Actual	Budget	2023 Actual
		(in thousands)			
Revenues					
Non-Renewable Resource Revenue					
Bitumen Royalty	$ 12,555,401	$ 14,517,568	$ 16,878,571	$ 1,962,167	$ (2,361,003)
Natural Gas and By-Products Royalty	2,465,402	1,057,468	3,595,463	(1,407,934)	(2,537,995)
Crude Oil Royalty	2,905,317	2,971,540	3,968,461	66,223	(996,921)
Bonuses and Sales of Crown Leases	306,594	498,551	464,801	191,957	33,750
Rentals and Fees	115,894	149,378	189,299	33,484	(39,921)
Coal Royalty	12,991	92,258	145,551	79,267	(53,293)
Total Non-Renewable Resource Revenue	18,361,599	19,286,763	25,242,146	925,164	(5,955,383)
Freehold Mineral Rights Tax	129,435	124,866	161,142	(4,569)	(36,276)
Transfers from Government of Canada	-	383	436,726	383	(436,343)
Industry Levies and Licenses	352,419	371,862	284,746	19,443	87,116
Other Revenue	6,401	10,994	28,767	4,593	(17,773)
Net Loss from Government Business Enterprises					
Alberta Petroleum Marketing Commission	(17,502)	(1,637,273)	(487,377)	(1,619,771)	(1,149,896)
Ministry total revenues	18,832,352	18,157,595	25,666,150	(674,757)	(7,508,555)
Inter-ministry consolidation adjustments	(1,597)	(1,193)	(162)	404	(1,031)
Ministry total revenues	18,830,755	18,156,402	25,665,988	(674,353)	(7,509,586)
Expenses - Directly Incurred					
Ministry Support Services	7,495	5,109	4,117	(2,386)	992
Resource Development and Management	88,865	73,047	71,590	(15,818)	1,457
Cost of Selling Oil	316,000	366,486	429,381	50,486	(62,895)
Carbon Capture and Storage	58,914	20,865	42,789	(38,049)	(21,924)
Economic Recovery Program	147,405	109,918	449,453	(37,487)	(339,535)
Energy Regulation	231,274	237,132	223,496	5,858	13,636
Orphan Well Abandonment	135,000	150,241	80,294	15,241	69,947
Ministry total expenses	984,953	962,798	1,301,120	(22,155)	(338,322)
Inter-ministry consolidation adjustments	(1,597)	(1,177)	(252)	420	(925)
Adjusted ministry total expenses	983,356	961,621	1,300,868	(21,735)	(339,247)
Annual Surplus before inter-ministry consolidation adjustments	17,847,399	17,194,797	24,365,030	(652,602)	(7,170,233)
Inter-ministry consolidation adjustments	-	(16)	90	(16)	(106)
Adjusted annual surplus	$ 17,847,399	$ 17,194,781	$ 24,365,120	$ (654,618)	$ (7,170,339)

Revenue and Expense Highlights

Revenues

Energy and Minerals' 2023–24 total revenues of $18.2 billion consists of the following:

- **Non-Renewable Resource revenues** totalling $19.3 billion were $0.9 billion higher than budget primarily due to bitumen royalties being $2.0 billion higher than budgeted. The increase was primarily due to a lower than forecasted foreign exchange rate and narrower light-heavy differentials, partially offset by lower than anticipated West Texas Intermediate prices and production levels.
- **Freehold Mineral Rights Tax revenues** totalled $125 million and relate to annual taxes on private freehold mineral rights and was $5 million lower than budget. This was due mainly to lower than anticipated oil and gas unit values.
- **Industry levies and licences** totalled $372 million and relate to levies and licenses collected from industry by the Alberta Energy Regulator (AER).
- **Other revenue** totalling $11 million was $5 million higher than budget, primarily due to higher than budgeted interest income generated by the AER.
- **Net loss from Government Business Enterprises** totalled $1.6 billion which was primarily from a provision taken by the Alberta Petroleum Marketing Commission on an onerous contract in the amount of $1.3 billion.

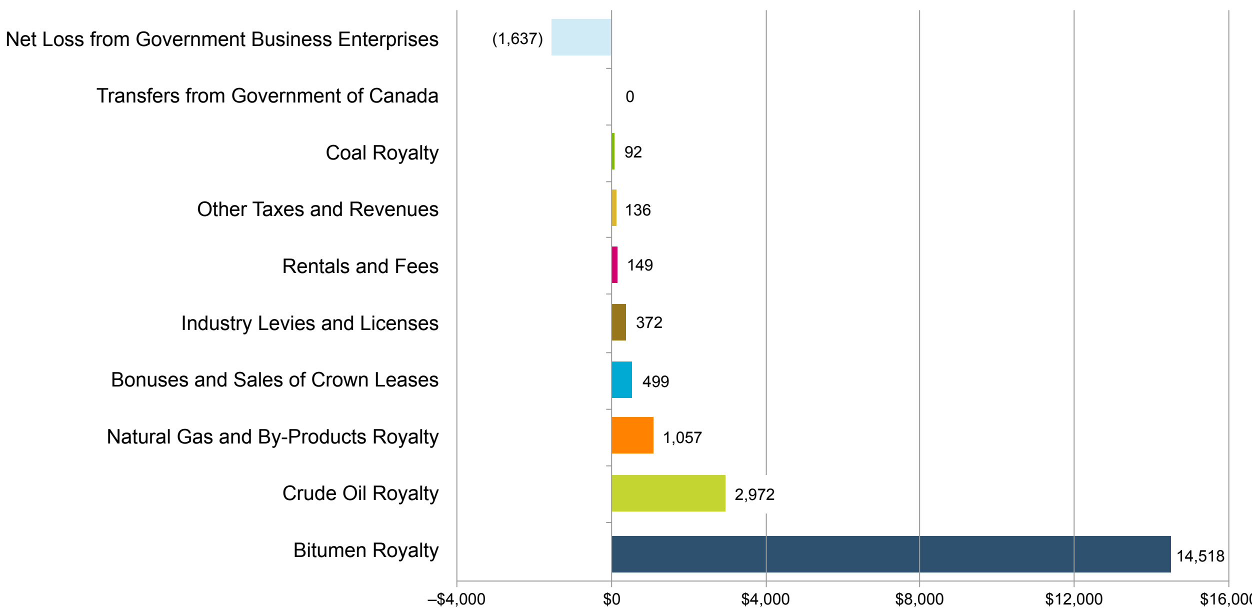
Expenses

Energy and Minerals' 2023–24 operating expenditures totalled $962 million, which was $22 million lower than budget. This was primarily related to surpluses for the Carbon Capture and Storage Program ($38 million), Economic Recovery Program ($37 million) and Resource Development and Management ($16 million), partially offset by higher than budgeted Costs of Selling Oil ($50 million) and Orphan Well Abandonment ($15 million).

- **Ministry Support Services** – Ministry support services captures the costs incurred by the office of the Minister, Deputy Minister and Corporate Services.
- **Resource Development and Management** – Resource development and management captures the costs incurred by the ministry to:
  - Develop strategic policies to support Alberta's energy and mineral resource markets;
  - Oversee 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; and
  - Advocate for Alberta's energy industry in Canada and internationally, which includes activities associated with the Canadian Energy Centre (CEC).
- These activities had an approved budget of $89 million. The ministry incurred a $16 million surplus, primarily due to reduced spending for the CEC and other industry advocacy activities to partially offset higher than anticipated costs of selling oil.
- **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 $50 million higher than budget, due primarily to higher than forecasted royalty deliveries that were driven by higher than budgeted crude oil barrels produced per day.

- **Carbon Capture and Storage Program** – This program supports two Carbon Capture and Storage projects in Alberta: The Shell Quest Project and the Alberta Carbon Trunk Line project. Due to lower than budgeted payments for CO2 injection volumes, this program spent $38 million less than budget.
- **Economic Recovery Program** – The costs included in this program relate primarily to the Alberta Petrochemicals Incentive Program. In 2023–24, the ministry incurred $110 million in grant expenditures based on production milestones. These grant payments were $37 million lower than budgeted.
- **Energy Regulation** – This represents the costs incurred by the Alberta Energy Regulator (AER) to support the regulation of Alberta's energy resources. The AER's activities are fully funded by industry levies.
- **Orphan Well Abandonment** expenses, totaling $150 million, 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.

2023–24 Actual
(in millions of dollars)



Breakdown of Revenues (unaudited)

The following information presents detailed revenues of the ministry, the majority of the ministry revenues are affected by market conditions. 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.

Non-Renewable Resource Revenue

Revenue ($ Millions)	2023–24 Budget	2023–24 Actual
Bitumen Royalty	12,555	14,518
Crude Oil Royalty	2,905	2,972
Natural Gas and By-Products Royalty	2,465	1,057
Bonuses and Sales of Crown Leases	307	499
Rentals and Fees	116	149
Coal Royalty	13	92
Non-Renewable Resource Revenue	***18,362**	**19,287**

*Totals may not add up due to rounding.

- **Bitumen royalties** remained the largest portion of resource royalty revenue. In 2023–24, actual bitumen royalty revenue totalled $14.5 billion, which was $2.0 billion higher than budget. This was mainly due to a lower than forecasted foreign exchange rate and narrower light-heavy price differentials, partially offset by lower than anticipated West Texas Intermediate (WTI) prices and production levels.
- **Conventional crude oil royalties** contributed $3.0 billion, $0.1 billion higher than budget. This was mainly due to a lower than forecasted foreign exchange rate and narrower light-heavy price differentials, partially offset by lower than anticipated WTI prices and production levels.
- **Natural gas and by-products** generated $1.1 billion of revenue, which was $1.4 billion lower than budget. This was mainly due to lower than budgeted prices for WTI and the Alberta Natural Gas Reference Price.
- **Bonuses and Sales of Crown Leases** totalled $499 million, which was $192 million higher than budget, mainly due to increases in the number of Petroleum and Natural Gas (PNG) hectares sold and a higher price per hectare for both PNG and Oil Sands, partially offset by a decrease in Oil Sands hectares sold.
- **Rentals and Fees** totalled $149 million, which was $33 million higher than budget. Rentals and fees revenue is tied to land sales in the current and previous years, where a lease or license holder pays rent every year and is also required to pay the first year of rent in full and upfront when their bid wins the bonus auction. Revenue was higher than budget mainly due to higher rental prices per hectare.
- **Coal royalty** totalled $92 million, which was $79 million higher than budget, mainly due to the impact of a coal mine moving into post-payout status in 2022–2023 and high global demand for coal.

Royalty Program Adjustments

The ministry has a number of royalty programs under the Alberta Royalty Framework, which ceased accepting new participants in 2017 and were phased out by December 31, 2021, or once their regulations expire. The remaining programs being phased out include the Enhanced Oil Recovery Program, Proprietary Waiver, and Otherwise Flared Solution Gas. The ministry will continue to monitor and report on the progress of all royalty programs until they have officially expired.

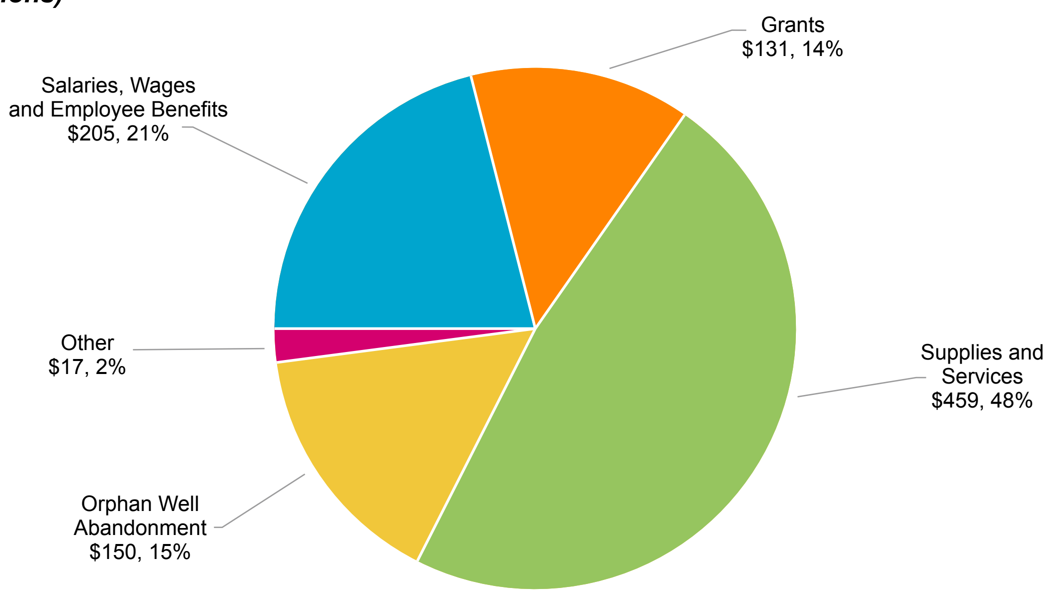
In 2023–24, Non-Renewable Resource Revenues are reported net of the following royalty program adjustments:

	2024	2023
Royalty Program	**(in thousands)**	
Enhanced Oil Recovery Program	6,910	28,788
Proprietary Waiver	2,751	8,282
Otherwise Flared Solution Gas	0	6
Total Royalty Program Adjustment	9,661	37,076

Expenses – Directly Incurred Detailed by Object (unaudited)

The following information presents expenses of the ministry that were directly incurred by object of expense. 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.

2024 Actual
(in millions)



- **Supplies and Services**, which represented 48 per cent of total operating expense, were the largest component of the ministry's operating expense ($459 million). This consisted primarily of the costs of selling oil ($366 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).
- **Salaries, Wages and Employee Benefits**, which represented 21 per cent of total operating expense ($205 million), primarily supported the collection of revenue, development of resource policy, regulatory work provided by the Alberta Energy Regulator (AER), and the overall support and management of ministry operations.
- **Orphan Well Abandonment**, which represented 15 per cent of total operating expense ($150 million), reflects the expenses incurred for reclamation of abandoned wells, facilities and pipelines that are licensed to defunct licensees, as delegated by the AER.
- **Grants**, which represented 14 per cent of total operating expense, were the second largest component of the ministry's operating expense ($131 million), and primarily consisted of payments related to the Alberta Petrochemicals Incentive Program ($110 million) and the Carbon Capture and Storage Program ($20 million).
- **Other expenses**, totaling $17 million (2 per cent), primarily consisted of amortization of tangible capital assets ($13 million) and allowances for doubtful accounts ($8 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, 2024, the Ministry of Energy and Minerals had gas royalty deposits of $593 million.

Financial Statements of Other Reporting Entities

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Alberta Energy Regulator

Consolidated Financial Statements

For the Year Ended March 31, 2024

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Independent Auditor's Report

Auditor General OF ALBERTA

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, 2024, and the consolidated statements of operations, change in net financial assets, 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, 2024, 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 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 16, 2024
Edmonton, Alberta

Consolidated Statement of Operations

Alberta Energy Regulator
Year Ended March 31, 2024

	2024		2023
	Budget (Note 5, Schedule 3)	Actual	Actual
		(in thousands)	
Revenues			
Administration fees	$ 217,419	$ 218,234	$ 201,429
Orphan fund levies and transfers (Note 6)	135,000	150,241	80,294
Government of Alberta grants	12,356	14,185	16,754
Information, services and fees	1,299	2,701	2,576
Investment income	2,700	7,223	4,085
	368,774	392,584	305,138
Expenses			
Energy regulation (Schedule 1)	231,274	237,132	223,496
Orphan well abandonment (Note 6)	135,000	150,241	80,294
	366,274	387,373	303,790
Annual operating surplus	2,500	5,211	1,348
Accumulated surplus at beginning of year	74,935	74,935	73,587
Accumulated surplus at end of year	$ 77,435	$ 80,146	$ 74,935

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

Consolidated Statement of Financial Position

Alberta Energy Regulator
As At March 31, 2024

	2024	2023
	(in thousands)	
Financial assets		
Cash and cash equivalents (Note 7)	$ 19,142	$ 43,171
Accounts receivable (Note 8)	2,641	2,927
Portfolio investments (Note 9)	19,902	-
Pension assets (Note 16)	13,737	9,903
	55,422	56,001
Liabilities		
Accounts payable and other accrued liabilities (Note 10)	25,317	26,017
Payable to Orphan Well Association	1,459	2,419
Deferred revenue (Note 11)	6,588	7,657
Deferred lease incentives (Note 13)	8,387	9,849
	41,751	45,942
Net financial assets	13,671	10,059
Non-financial assets		
Tangible capital assets (Note 17)	57,723	56,672
Prepaid expenses and other assets	8,752	8,204
	66,475	64,876
Net assets		
Accumulated surplus (Note 18)	$ 80,146	$ 74,935

Asset Retirement Obligation (Note 15)
Contractual rights (Note 19)
Contingent liabilities (Note 20)
Contractual obligations (Note 21)

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

Consolidated Statement of Change in Net Financial Assets

Alberta Energy Regulator
Year Ended March 31, 2024

	2024		2023
	Budget (Note 5, Schedule 3)	Actual	Actual
		(in thousands)	
Annual operating surplus	$ 2,500	$ 5,211	$ 1,348
Acquisition of tangible capital assets (Note 17)	(14,500)	(14,114)	(12,808)
Amortization of tangible capital assets (Note 17)	12,000	12,903	13,114
Net loss on disposal and write-down of tangible capital assets		148	418
Proceeds on disposal of tangible capital assets		12	47
(Increase)/decrease in prepaid expenses and other assets		(548)	438
Decrease in spent deferred capital contributions (Note 11)		-	(240)
Increase in net financial assets	-	3,612	2,317
Net financial assets at beginning of year	10,059	10,059	7,742
Net financial assets at end of year	$ 10,059	$ 13,671	$ 10,059

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

Consolidated Statement of Cash Flows

Alberta Energy Regulator
Year Ended March 31, 2024

	2024	2023
	(in thousands)	
Operating transactions		
Annual operating surplus	$ 5,211	$ 1,348
Non-cash items included in annual operating surplus:		
Amortization of tangible capital assets (Note 17)	12,903	13,114
Change in pension assets	(3,834)	(5,945)
Net loss on disposal and write-down of tangible capital assets (Note 17)	148	418
Bad debt expense	1,325	34
Amortization of deferred lease incentives (Note 13)	(1,462)	(1,466)
	14,291	7,503
Increase in accounts receivable	(1,039)	(1,277)
(Increase)/decrease in prepaid expenses and other assets	(548)	438
Decrease in accounts payable and other accrued liabilities	(700)	(708)
(Decrease)/increase in payable to Orphan Well Association	(960)	1,355
Decrease in deferred revenue	(1,069)	(3,705)
Cash provided by operating transactions	9,975	3,606
Capital transactions		
Acquisition of tangible capital assets (Note 17)	(14,114)	(12,808)
Proceeds on disposal of tangible capital assets	12	47
Cash applied to capital transactions	(14,102)	(12,761)
Investing transactions		
Purchase of portfolio investments (Note 9)	(19,902)	-
Cash applied to investing transactions	(19,902)	-
Financing transactions		
Decrease in spent deferred capital contributions (Note 11)	-	(240)
Cash applied to financing transactions	-	(240)
Decrease in cash and cash equivalents	(24,029)	(9,395)
Cash and cash equivalents at beginning of year	43,171	52,566
Cash and cash equivalents at end of year	$ 19,142	$ 43,171

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

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2024

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 efficient, safe, orderly and environmentally responsible development of energy and mineral resources in Alberta through regulatory activities. 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 transactions with no performance obligations, such as administration fees and orphan fund levies, at their realizable value. Revenue from transactions with performance obligations, including information, services and fees, is recognized when the AER provides the promised goods and/or service to a payor.

Cash received for goods and/or services not yet provided before year end is recognized as deferred revenue and recorded in accounts payable and other accrued liabilities.

<u>Government of Alberta grants</u>

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.

<u>Investment income</u>

Investment income includes interest income and realized gains and losses on the sale of portfolio investments. Once realized, these gains or losses are recognized in the Consolidated Statement of Operations.

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.

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2024

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

Basis of Financial Reporting (continued)

Employee future benefits (continued)
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.

Actuarial gains and losses are amortized over the average remaining service period of the active employees, which is 11.1 years (2023 - 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
Portfolio investments	Amortized cost
Pension assets	Lower of cost or net recoverable value
Accounts payable and other accrued liabilities	Cost
Payable to the Orphan Well Association	Cost
Environmental Liabilities	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, 2024

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

Basis of Financial Reporting (continued)

Portfolio investments

Portfolio investments are recognized at amortized cost. Investment premiums and discounts are amortized proportionately over the term of the respective investments using an effective interest method. Any declines in market value below costs are considered to be temporary and therefore no write-downs have been recorded.

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.

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, 2024

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	3 - 10 years
Vehicle	Straight line	5 - 15 years
Computer hardware	Straight line	3 - 10 years
Computer software - purchased	Straight line	3 - 10 years
Computer software - developed	Straight line	3 - 10 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 CHANGE IN ACCOUNTING STANDARDS

Effective April 1, 2023, the AER adopted the new accounting standard PS 3400 Revenue. There were no changes to the measurement of revenues on adoption of the new standard.

At the beginning of the same fiscal reporting period, the AER also adopted the PSG-8 Purchased Intangibles Guideline. There was no impact on the Consolidated Financial Statements as a result of adoption of the new guideline.

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2024

Note 4 FUTURE CHANGES IN ACCOUNTING STANDARDS

The Public Sector Accounting Board has approved the following accounting standards, which are effective for fiscal years starting on or after April 1, 2026:

The Conceptual Framework for Financial Reporting in the Public Sector
The Conceptual Framework is the foundation for public sector financial reporting standard setting. It replaces the conceptual aspects of Section PS 1000 Financial Statement Concepts and Section PS 1100 Financial Statement Objectives. The conceptual framework highlights considerations fundamental for the consistent application of accounting issues in the absence of specific standards.

PS 1202 Financial Statement Presentation
Section PS 1202 sets out general and specific requirements for the presentation of information in general purpose financial statements. The financial statement presentation principles are based on the concepts within the Conceptual Framework.

Management is currently assessing the impact of the conceptual framework and the standard on the Consolidated Financial Statements.

Note 5 BUDGET

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

Note 6 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, 2024, the AER invoiced $135,516 (2023 - $78,090) in levies and penalties. Additionally, the AER collected and transferred $14,260 (2023 - $1,535) in forfeited security deposits and $465 (2023 - $669) in application fees.

Note 7 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, 2024, the AER earned interest at an annual average rate of 5.5% (2023 - 3.5%).

Cash and cash equivalents includes restricted funds of $6,411 (2023 - $7,447), as reflected in deferred revenue (discussed in Note 11).

Note 8 ACCOUNTS RECEIVABLE
(in thousands)

Accounts receivable are unsecured and non-interest bearing.

	2024			2023
	Gross amount	Allowance for doubtful accounts	Net recoverable value	Net recoverable value
Accounts receivable	$ 4,091	$ (1,450)	$ 2,641	$ 2,927

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2024

Note 9 PORTFOLIO INVESTMENTS
(in thousands)

	2024		2023	
	Book value	Fair value	Book value	Fair value
Bonds	$ 19,869	$ 19,621	-	-
Other	33	33	-	-
	$ 19,902	$ 19,654	$ -	$ -

The bonds are intended to be held long term with interest rates from 2.0% to 6.2% and maturity dates between 2026 and 2034. Any declines in market value below costs are considered to be temporary and therefore no write-downs have been recorded.

Note 10 ACCOUNTS PAYABLE AND OTHER ACCRUED LIABILITIES
(in thousands)

	2024	2023
Trade and other accrued liabilities	$ 11,839	$ 9,743
Lease termination payable	3,716	5,820
Accrued salaries and benefits	9,762	10,454
	$ 25,317	$ 26,017

Note 11 DEFERRED REVENUE
(in thousands)
Deferred revenue consists of the following:

	2024	2023
Deferred contributions(1)	$ 6,411	$ 7,447
Unearned revenue	177	210
	$ 6,588	$ 7,657

(1) Deferred contributions

	2024			2023
	Government of Alberta	Other	Total	Total
Balance at beginning of year	$ 7,134	$ 313	$ 7,447	$ 11,159
Cash contributions received/receivable during year	12,928	627	13,555	13,158
Less: amounts recognized as revenue	(14,185)	(311)	(14,496)	(16,870)
Less: unused amounts returned	(95)	-	(95)	-
Balance at end of year	$ 5,782	$ 629	$ 6,411	$ 7,447

Note 12 FINANCIAL INSTRUMENTS

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

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2024

Note 12 FINANCIAL INSTRUMENTS (continued)

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.

(b) Credit risk

The AER is exposed to credit risk from potential non-payment of accounts receivable and from the failure of a counterparty to fully honour its financial obligations with the AER. 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.

The AER is exposed to credit risk associated with the underlying debt securities held in investment funds managed by the Canadian Imperial Bank of Commerce (CIBC). All of the AER's investments in bonds are with counterparties considered to be investment grade (AAA to BBB-) at March 31, 2024.

(c) Interest Rate Risk

The AER is exposed to interest rate associated with the underlying interest-bearing securities held in the investment funds. Interest rate risk relates to the possibility that the fair value of investments will change due to future fluctuations in market interest rates. In general, investment returns from bonds are sensitive to changes in the level of interest rates, with longer term interest bearing securities being more sensitive to interest rate changes than shorter-term bonds. If interest rates increased by 1%, and all other variables are held constant, the potential loss in fair value to the AER would be approximately 6.4% of total investments.

The following table summarizes the terms to maturity of interest-bearing securities held in bond investments at March 31, 2024.

Class	< 1 year	1-5 years	Over 5 years	Average effective market
Bonds	-	4	5	5.4%

Note 13 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.

	2024			2023
	Leasehold improvement costs	Reduced rent benefits and rent-free periods	Total	Total
Balance at beginning of year	$ 8,234	$ 1,615	$ 9,849	$ 11,315
Amortization	(1,133)	(329)	(1,462)	(1,466)
Balance at end of year	$ 7,101	$ 1,286	$ 8,387	$ 9,849

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2024

Note 14 ENVIRONMENTAL LIABILITIES

(in thousands, unless otherwise noted)

The AER has a mandate to protect public safety and the environment. As at March 31, 2024, the AER is administering 30 (2023 – 29) legacy sites on behalf of the Government of Alberta. Of these sites, during the year ended March 31, 2024, the AER identified one (2023 – one) site 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, 2024, the AER incurred $4 (2023 - $3) 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.

As at March 31, 2024, the AER is not responsible, nor has it accepted responsibility, for performing remediation and reclamation work at contaminated sites. The AER has $nil (2023 - $nil) environmental liabilities recorded.

Note 15 ASSET RETIREMENT OBLIGATION

Tangible capital assets are assessed for asset retirement obligations annually. Asset retirement obligations are initially measured as of the date the legal obligation was incurred, based on management's best estimate of the amount required to retire tangible capital assets and subsequently re-measured taking into account any new information and the appropriateness of assumptions used. At March 31, 2024, the estimate of the liability is insignificant and therefore no liability was recognized. During the year ended March 31, 2024, the AER incurred $nil (2023 - $nil) in costs to settle the obligation.

Note 16 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, 2024, the expense for these pension plans is equal to the contributions of $12,357 (2023 - $12,207) 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, 2021. The accrued benefit obligation as at March 31, 2024 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, 2024, the weighted average actual return on plan assets was 6.6% (-1.9% in 2023).

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

Accrued benefit obligations	2024	2023
Discount rate	5.3%	5.4%
Rate of compensation increase	6.0% until March 31, 2024, 3.0% thereafter	4.0% until March 31, 2023, 6.0% until March 31, 2024, 3.0% thereafter
Long-term inflation rate	2.0%	2.0%

Pension benefit costs for the year	2024	2023
Discount rate	5.4%	4.5%
Expected rate of return on plan assets	5.4%	4.5%
Rate of compensation increase	6.0% until March 31, 2024, 3.0% thereafter	4.0% until March 31, 2023, 3.0% thereafter

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2024

Note 16 EMPLOYEE FUTURE BENEFITS (continued)

(in thousands, unless otherwise noted)

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

	2024	2023
Market value of plan assets	$ 90,265	$ 81,577
Accrued benefit obligations	(72,374)	(67,126)
Plan surplus	17,891	14,451
Unamortized actuarial gains	(4,154)	(4,548)
Pension assets	$ 13,737	$ 9,903

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

	2024	2023
Current period benefit cost	$ 2,421	$ 3,921
Interest cost	3,705	3,277
Expected return on plan assets	(4,549)	(3,462)
Amortization of actuarial gains	(280)	(67)
	$ 1,297	$ 3,669

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

	2024	2023
Benefits paid	$ 2,756	$ 4,189
AER contributions	5,134	9,615
Employees' contributions	850	751

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

	2024	2023
Equity securities	44.9%	45.4%
Debt securities	24.6%	24.3%
Alternatives	19.7%	18.5%
Other	10.8%	11.8%
	100.0%	100.0%

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2024

Note 17 TANGIBLE CAPITAL ASSETS
(in thousands)

	2024						2023
	Land	**Leasehold improvements**	**Furniture and equipment**	**Vehicle (1)**	**Computer hardware and software**	**Total**	**Total**
Estimated useful life	Indefinite	Term of the lease	3-10 years (2)	5-15 years	3-10 years (2)		
Historical cost (3)							
Beginning of year	$ 282	$ 47,623	$ 12,902	$ -	$ 140,256	$ 201,063	$ 197,386
Additions	-	1,477	257	584	11,796	14,114	12,808
Disposals, including write-downs	-	-	(660)	-	(4,275)	(4,935)	(9,131)
	282	49,100	12,499	584	147,777	210,242	201,063
Accumulated amortization							
Beginning of year	$ -	$ 26,989	$ 10,029	$ -	$ 107,373	$ 144,391	$ 139,943
Amortization expense	-	2,646	941	74	8,287	$ 11,948	13,114
Effect of disposals, including write-downs	-	-	(590)	-	(4,185)	$ (4,775)	(8,666)
Transfers and adjustments (4)	-	-	576	-	379	$ 955	-
	-	29,635	10,956	74	111,854	152,519	144,391
Net book value at March 31, 2024	$ 282	$ 19,465	$ 1,543	$ 510	$ 35,923	$ 57,723	
Net book value at March 31, 2023	$ 282	$ 20,634	$ 2,873	$ -	$ 32,883		$ 56,672

(1) A new tangible capital asset class has been added effective April 1, 2023 prospectively for purchased vehicles.

(2) The estimated useful lives for furniture and equipment, and computer hardware and software have changed to 3-10 years following a policy review. These changes in accounting estimate have been accounted for prospectively, effective April 1, 2023.

(3) Historical costs include work-in-progress at March 31, 2024 totalling $12,055 (2023 - $6,381) comprised of: computer hardware and software of $10,896 (2023 - $6,369) and leasehold improvements of $1,159 (2023 - $12).

(4) Transfers and adjustments solely relate to accounting policy alignments and reclassifications between capital asset categories.

Note 18 ACCUMULATED SURPLUS
(in thousands)

Accumulated surplus is comprised of the following:

	2024			2023
	Investments in tangible capital assets (1)	**Unrestricted net assets**	**Total**	**Total**
Balance at beginning of year	$ 48,438	$ 26,497	$ 74,935	$ 73,587
Annual operating surplus	-	5,211	5,211	1,348
Net investment in tangible capital assets (1)	2,184	(2,184)	-	-
Balance at end of year	$ 50,622	$ 29,524	$ 80,146	$ 74,935

(1) 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, 2024

Note 19 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:

	2024	2023
Contractual rights from operating subleases	$ 592	$ 543

As at March 31, 2024, estimated amounts that will be received or receivable for each of the next five years are as follows:

2024-25	433
2025-26	439
2026-27	182
2027-28	-
2028-29	-
	$ 1,054

Note 20 CONTINGENT LIABILITIES
(in thousands, unless otherwise noted)

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, 2024, accruals totalling $25 (2023 - $1,312) have been recognized as a liability. The AER has been jointly named with the Government of Alberta in Athabasca Chipewyan First Nation claim that has a total amount claimed of $500 million in March 2024, the outcome of which is not determinable.

The AER has identified various sites where contamination may exist and the level of contamination is unknown at this time. As at March 31, 2024, no liability has been recognized for these sites as the AER is acting as an administrator on behalf of the Government of Alberta. No liability for remediation on other sites has been recognized as the AER becoming responsible for these sites is unlikely. The AER's ongoing efforts to monitor contaminated sites may result in environmental remediation liabilities related to newly identified sites, change in the assessment or intended use of existing sites, or change in responsibility. Any change to the environmental liabilities will be accrued in the year in which they are assessed as likely and measurable if they are deemed to be the AER's responsibility.

Note 21 CONTRACTUAL OBLIGATIONS
(in thousands)

As at March 31, 2024, the AER had contractual obligations totalling $146,267 (2023 - $125,189).

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, 2024, estimated payment requirements for obligations under operating leases and contracts for each of the next five years and thereafter are as follows:

2024-25	$ 54,575
2025-26	24,762
2026-27	18,238
2027-28	14,122
2028-29	11,704
Thereafter	22,866
	$ 146,267

Notes to the Consolidated Financial Statements

Alberta Energy Regulator
March 31, 2024

Note 22 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, assets under administration included the following types of security deposits:

	2024				2023
	Cash	Letters of credit	Surety Bond	Total	Total
Liability Management Rating programs and landfills	$ 107,155	$ 319,472	$ -	$ 426,627	$ 384,328
Mine Financial Security program	118,461	1,007,981	561,422	1,687,864	1,559,734
Other programs	11,869	13,523	5,628	31,020	21,984
	$ 237,485	$ 1,340,976	$ 567,050	$ 2,145,511	$ 1,966,046

Note 23 COMPARATIVE FIGURES

Certain 2023 figures have been reclassified, where necessary, to conform to the 2024 presentation.

Note 24 APPROVAL OF CONSOLIDATED FINANCIAL STATEMENTS

These Consolidated Financial Statements were approved by the AER Board of Directors on May 16, 2024.

Energy Regulation Expenses - Detailed By Object

Alberta Energy Regulator
Year Ended March 31, 2024
Schedule 1

	2024	2023
	(in thousands)	
Salaries, wages and employee benefits	$ 155,370	$ 147,068
Consulting services	23,380	22,608
Computer services	20,668	17,801
Buildings	19,056	18,848
Amortization of tangible capital assets	12,903	13,114
Administrative	2,798	1,703
Travel and transportation	2,511	1,640
Equipment rent and maintenance	298	296
Loss on disposal and write-down of tangible capital assets	148	418
	$ 237,132	$ 223,496

Salary and Benefits Disclosure

Alberta Energy Regulator
Year Ended March 31, 2024
Schedule 2

	2024				2023 Restated (4)
	Base salary (1)	Other cash benefits (2)	Other non-cash benefits (3)	Total	Total
			(in thousands)		
Position					
Board Members (5)	$ 500	$ -	$ 34	$ 534	$ 498
President and Chief Executive Officer	341	36	88	465	465
Chief Hearing Commissioner (4)	247	12	64	323	301
Chief Operations Officer (4)	285	15	88	388	374
Executive Vice-President, Law and General Counsel (4)	281	12	98	391	328
Vice-President of Finance and Chief Financial Officer (4)	252	10	92	354	338
Vice-President of People, Culture and Learning (4)	241	5	74	320	316
Former Executive Vice-President, Law and General Counsel	-	-	-	-	72

(1) Includes retainers and per diems for Board Directors and regular salary and acting pay for Executives.

(2) Other cash benefits include payments in lieu of vacation, pension and health benefits, as well as vehicle allowances and other cash reimbursements. There were no bonuses paid in 2024.

(3) Other non-cash benefits include 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.

(4) The 2023 figures have been restated to include the retroactive application of salary increases.

(5) As at March 31, 2024, the Board of Directors consisted of seven members.

Salary and Benefits Disclosure

Alberta Energy Regulator
Year Ended March 31, 2024
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, 2023 and 2024, 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.

	2024			2023
Position	Current service cost	Prior service and other costs	Total	Total
Executive Vice-President, Law and General Counsel	$ 22	$ (5)	$ 17	$ 23
Vice-President of Finance and Chief Financial Officer	29	(2)	27	32
Vice-President of People, Culture and Learning	21	(2)	19	28

The SEPP and SRP accrued obligation for each executive employed by the AER during the years ended March 31, 2023 and 2024 is outlined in the following table:

Position	Accrued obligation April 1, 2023	Changes in accrued obligation	Accrued obligation March 31, 2024	Accrued obligation March 31, 2023
Executive Vice-President, Law and General Counsel	$ 198	$ 46	$ 244	$ 198
Vice-President of Finance and Chief Financial Officer	93	46	139	93
Vice-President of People, Culture and Learning	70	30	100	70

Consolidated Actual Results Compared With Budget

Alberta Energy Regulator
Year Ended March 31, 2024
Schedule 3

	Budget (Note 5)	Adjustments [1]	Adjusted budget	Actual
		(in thousands)		
Revenues				
Administration fees	$ 217,419	$ 833	$ 218,252	$ 218,234
Orphan fund levies and transfers	135,000	665	135,665	150,241
Government of Alberta grants	12,356	7,039	19,395	14,185
Information, services and fees	1,299	-	1,299	2,701
Investment income	2,700	4,422	7,122	7,223
	368,774	12,959	381,733	392,584
Expenses				
Energy regulation	231,274	12,294	243,568	237,132
Orphan well abandonment	135,000	665	135,665	150,241
	366,274	12,959	379,233	387,373
	2,500	-	2,500	5,211
Capital				
Capital investment	14,500		14,500	14,114
Less: Amortization of tangible capital assets	(12,000)		(12,000)	(12,903)
Net loss on disposal and write-down of tangible capital				(148)
Proceeds on disposal of tangible capital assets				(12)
Net capital investment	2,500	-	2,500	1,051
Surplus	$ -	$ -	$ -	$ 4,160

[1] Adjustments reflect changes to the original budget approved by the Treasury Board. The adjustments reflect the utilization of grant funding received in 2023 to accommodate work completed in 2024 related to mandate expansion activities, higher investment income resulting from the AER issuing the levies earlier than initially planned and rising interest rates, adjustments to reflect administration fee penalties issued, along with projected first-time license fees which were transferred to the Orphan Well Association.

Related Party Transactions

Alberta Energy Regulator
Year Ended March 31, 2024
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 2024, 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	
	2024	2023	2024	2023
	(in thousands)		*(in thousands)*	
Revenues				
Government of Alberta grants	$ 14,185	$ 16,754	$ -	$ -
Information, services and fees	346	333	700	671
	$ 14,531	$ 17,087	$ 700	$ 671

	Entities in the Ministry of Energy		Other entities	
	2024	2023	2024	2023
	(in thousands)		*(in thousands)*	
Expenses				
Computer services	$ 414	$ 341	$ 3,006	$ 3,441
Buildings	-	-	505	433
Administrative	-	-	476	515
Consulting services	-	-	182	174
	$ 414	$ 341	$ 4,169	$ 4,563
Receivable from	$ 145	$ 130	$ 14	$ 13
Prepaid expenses and other assets	$ -	$ -	$ 38	$ 36
Payable to	$ -	$ -	$ 1,216	$ 1,987
Deferred revenue	$ 5,782	$ 7,134	$ 133	$ 200
Contractual obligations [1]	$ -	$ -	$ 6,210	$ 3,869

[1] 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 Petroluem Marketing Commission

Consolidated Financial Statements

For the Year Ended March 31, 2024

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Independent Auditor's Report

Auditor General OF ALBERTA

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, 2024, and the consolidated statements of loss and comprehensive loss, changes in deficit, and cash flows for the year then ended, and notes to the consolidated financial statements, including material accounting policy information.

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, 2024, 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.

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

May 30, 2024
Edmonton, Alberta

Consolidated Statement of Financial Position

Alberta Petroleum Marketing Commission
(Expressed in thousands of Canadian dollars)

	Note	**March 31, 2024**	March 31, 2023
ASSETS			
Cash and cash equivalents	6	**28,711**	45,337
Restricted cash	7	**54,123**	76,633
Accounts receivable	8	**546,381**	463,438
Inventory	9	**72,010**	70,607
Total current assets		**701,225**	656,015
Investment in KXL Expansion Project	10	**9,743**	33,000
Investment in North West Redwater Partnership	11	**259,168**	230,324
Corporate assets		**545**	606
Intangible assets	12	**5,588**	6,652
Inventory	9	**6,877**	6,877
Total assets		**983,146**	933,474
LIABILITIES			
Accounts payable and accrued liabilities	13	**473,377**	389,109
Due to the Department of Energy and Minerals	14	**194,722**	211,359
Short term debt	15	**1,495,911**	1,240,659
Accrued interest payable	16	**31,043**	27,483
Long term debt	15	**409,509**	—
Lease liabilities		**61**	64
Sturgeon Refinery Processing Agreement provision	18	**231,800**	—
Total current liabilities		**2,836,423**	1,868,674
Long term debt	15	**962,398**	1,378,392
License fee provision	17	**134,000**	87,000
Lease liabilities		**364**	374
Sturgeon Refinery Processing Agreement provision	18	**1,757,200**	669,000
Total liabilities		**5,690,385**	4,003,440
SHAREHOLDERS' DEFICIT			
Deficit		**(4,707,239)**	(3,069,966)
Total liabilities and shareholders' deficit		**983,146**	933,474

Commitments note 20

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statement of Loss and Comprehensive Loss

Alberta Petroleum Marketing Commission

(Expressed in thousands of Canadian dollars)

	Note	Years Ended March 31, 2024	2023
REVENUES			
Refinery sales	22	**2,669,457**	2,733,082
Marketing fee income		**14,585**	12,050
		2,684,042	2,745,132
Finance income		**4,619**	2,580
Total revenue		**2,688,661**	2,747,712
EXPENSES			
Refinery feedstock purchases		**1,917,715**	1,884,148
Refinery tolls		**930,666**	878,508
Turnaround expenditures	23	**1,498**	164,279
General and administrative	24	**13,743**	11,560
Depreciation and amortization		**1,174**	1,166
Loss (gain) on foreign exchange		**280**	(5,802)
Finance costs	26	**174,640**	101,492
Loss (Income) from North West Redwater Partnership	11	**13,016**	(97,361)
Sturgeon Refinery Processing Agreement provision	18	**1,263,135**	289,250
Change in Sturgeon Refinery credit loss provision	19	**1,370**	16,903
Fair value loss (gain) on investment in KXL Expansion Project	10	**14,273**	(9,054)
Total expenses		**4,331,510**	3,235,089
Net loss and comprehensive loss before income taxes		**(1,642,849)**	(487,377)
Income tax recovery	27	**(5,576)**	—
Net loss and comprehensive loss		**(1,637,273)**	(487,377)

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statement of Cash Flows

Alberta Petroleum Marketing Commission
(Expressed in thousands of Canadian dollars)

		Years ended March 31,	
	Note	**2024**	2023
OPERATING ACTIVITIES			
Net loss and comprehensive loss		**(1,637,273)**	(487,377)
Adjusted for items not involving cash:			
Amortization of premium on long term debt	26	**(6,485)**	(16,518)
Depreciation and amortization		**1,174**	1,166
Accretion expenses	26	**62,005**	37,170
Fair value loss (gain) on investment in KXL Expansion Project	10	**14,273**	(9,054)
Unrealized foreign exchange loss (gain)		**60**	(5,716)
Loss (income) from North West Redwater Partnership	11	**13,016**	(97,361)
Change for credit loss provision	19	**(16,334)**	17,060
Change to loss provision for Sturgeon Refinery Processing Agreement	18	**1,263,135**	289,250
Changes in accrued interest payable	16	**3,560**	19,929
Changes in non-cash working capital	28	**22,129**	29,784
Net cash used in operating activities		**(280,740)**	(221,667)
FINANCING ACTIVITIES			
Payment of lease liabilities		**(62)**	(61)
Proceeds from short term and long term debt	15	**415,291**	2,492,206
Repayment of short term debt	15	**(160,039)**	(2,315,557)
Net cash provided by financing activities		**255,190**	176,588
INVESTING ACTIVITIES			
Liquidation proceeds received on KXL investment	10	**8,924**	63,770
Expenditures on property, plant, and equipment		**—**	(55)
Net cash provided by investing activities		**8,924**	63,715
Net change in cash and cash equivalents		**(16,626)**	18,636
Cash and cash equivalents, beginning of year		**45,337**	26,701
Cash and cash equivalents, end of year		**28,711**	45,337
Cash paid			
Interest received		**4,619**	2,580
Interest paid		**115,560**	(60,911)
Taxes received		**5,576**	—

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statement of Changes in Deficit

Alberta Petroleum Marketing Commission
(Expressed in thousands of Canadian dollars)

($000s)	
Deficit, March 31, 2022	(2,582,589)
Net loss and comprehensive loss for the period	(487,377)
Deficit, March 31, 2023	(3,069,966)
Net loss and comprehensive loss for the period	**(1,637,273)**
Deficit, March 31, 2024	**(4,707,239)**

The accompanying notes are an integral part of these consolidated financial statements.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission
For the Year Ended March 31, 2024
(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 interest 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 wholly owned by the Crown that 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 and Minerals. 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" or "KXL Investment").

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 Alberta Crown agency, 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 May 30, 2024.

The Commission conducts its principal business in four reportable operating segments (note 29).

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 issued by the International Accounting Standards Board ("IASB") and related interpretations as issued by the IFRS Interpretations Committee ("IFRIC").

(b) 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.

(c) Functional and presentation currency

The Annual Financial Statements are presented in Canadian dollars, which is also the APMC's functional and presentation currency.

(d) Use of estimates, assumptions and judgements

In preparing the Annual Financial Statements management has made judgements, estimates and assumptions that affect the application of APMC's 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 prospectively. Critical estimates and judgments used in the preparation of the Annual Financial Statements are described in note 4.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission
For the Year Ended March 31, 2024
(Expressed in thousands of Canadian dollars, unless stated otherwise)

3. SUMMARY OF 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 31 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.

(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 arrangements are 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.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission
For the Year Ended March 31, 2024
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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 Statement of Loss and Comprehensive 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 Statement of Loss and Comprehensive 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.

(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.

Cash and cash equivalents that are not available for use are classified as restricted cash.

(e) Prepaid expenses

Prepaid expenses relate to payments made in advance of receiving the related services and include tolls paid to NWRP in respect of turnaround costs under the Sturgeon Refinery Processing Agreement. The payments are expected to yield economic benefits over one or more future periods. Subsequent to initial recognition, prepaid expenses are recognized as expenses in the Consolidated Statement of Loss and Comprehensive Loss as the services are received, or are de-recognized when it is determined there is no longer future economic benefit.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission
For the Year Ended March 31, 2024
(Expressed in thousands of Canadian dollars, unless stated otherwise)

(f) Inventory

Inventory is maintained to support APMC's operations at the Sturgeon Refinery. Inventory is comprised of blended feedstock, intermediates and products. 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, oil inventory is managed on behalf of the Department of Energy and Minerals ("EM"). 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.

(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 Statement of Loss and Comprehensive Loss.

If the circumstances leading to the impairment are no longer present, an impairment loss may be reversed. 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. The impairment loss reversals are recognized in the Consolidated Statement of Loss and Comprehensive Loss.

(i) 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 paid by the EM. Collection of revenue occurs on or about the 25th 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

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission
For the Year Ended March 31, 2024
(Expressed in thousands of Canadian dollars, unless stated otherwise)

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.

(j) 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 measured 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 Statement of Loss and Comprehensive Loss when the asset is derecognized, modified or impaired.

Financial assets measured 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 and this investment does not meet the SPPI test (note 10). 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 Statement of Loss and Comprehensive Loss.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission
For the Year Ended March 31, 2024
(Expressed in thousands of Canadian dollars, unless stated otherwise)

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 is used to calculate the impairment provision. The matrix looks at a different percentage applied against each aging category, including the current amounts. The internal and external credit rating of a counterparty are 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 ("ECL") as the 12 month expected credit loss.

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.

Changes in the provision for ECL are recognized on the Consolidated Statement of Loss and Comprehensive 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 and Minerals, 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; or
- 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.

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(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.

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 is 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.

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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.

(k) 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 in finance costs.

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. 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 Loss and Comprehensive 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 Statement of Loss and Comprehensive Loss. If the contract is no longer onerous, then the provision is reversed in its entirety (i.e. the contract cannot become an asset).

(l) Finance income and finance expenses

Finance income related to the Sturgeon Refinery is comprised of interest income earned daily on cash and cash equivalents.

Finance expenses consist of interest expense on debt obligations, net of the unwinding of premiums recognized on the issuance of debt, and accretion expenses on the license fee provision and Surgeon Refinery Processing Agreement provision.

(m) 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.

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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.

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 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.

4. CRITICAL ACCOUNTING JUDGMENTS AND KEY SOURCES OF ESTIMATION UNCERTAINTY

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 revenues, expenses, assets, liabilities, and the disclosure of contractual obligations and contingencies, if any, at the date of the Annual Financial Statements. 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 prospectively.

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) 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. The Commission has the

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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. The Commission remits the net proceeds from the sale of product to the EM, and therefore does not have the ability to obtain the benefits from the crude oil. As the APMC does not 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 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 Canadian Natural Resources Limited ("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.

(b) Interests in Sturgeon Refinery

APMC indirectly 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 receive substantially all of the economic output of the Sturgeon Refinery as it is anticipated the life of the refinery will exceed the contractual term of the processing agreement.

NWRP processes bitumen and sells the refined products on behalf of the Tollpayers. APMC is providing the Sturgeon Refinery with 37,500 barrels a day ("bbl/d") of bitumen feedstock and the other Tollpayer provides the remaining 12,500 bbl/d of bitumen feedstock under a 40 year cost-for-service tolling agreements (collectively, the "Processing Agreements"). 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.

(c) NWRP - Monthly toll commitment

The Commission has used judgment to estimate its' toll commitments pursuant to the Processing Agreement included in note 20. 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 (West Texas Intermediate ("WTI") and light/heavy differentials), refined product prices, gas prices and foreign exchange rates.

(d) 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

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order to perform the onerous contract analysis, APMC management developed estimates for the key variables based primarily on GOA forecasts.

(e) Contingent consideration

In connection with APMC's acquisition of a 50 percent equity interest in NWRP, 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 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 CO2 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 CO2 licensing fee may be adjusted in future periods based upon the operating performance of the Sturgeon Refinery.

(f) ***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 measured at fair value through profit or loss as described in IFRS 9 *Financial Instruments*.

(g) 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, 2024 and 2023 using a probability-weighted valuation technique. The fair value of the KXL Investment is included in Level 3 of the fair value hierarchy (note 10 and 19) 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.

(h) Operating segments

The Commission has reviewed and determined its operating segments as disclosed in note 29.

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5. NEW ACCOUNTING POLICIES

Amendments to IAS 8: Definition of Accounting Estimates

On April 1, 2023, APMC adopted amendments to *IAS 8: Definition of Accounting Estimates ("IAS 8")* issued by the IASB which helped distinguish between accounting policies and estimates.

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; and
- 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 adoption of the amendments to *IAS 8* occurred prospectively and did not have a material impact to APMC's financial statements.

Amendments to IAS 1: Disclosure of accounting policies

In February 2021, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" ("IAS 1") to require companies to disclose their material accounting policy information rather than their significant accounting policies. To support this amendment the IASB also amended IFRS Practice Statement 2 "Making Materiality Judgements". The amendments were adopted on April 1, 2023 and did not have a significant impact on the APMC's consolidated financial statements.

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.

In October 2022, the IASB made further amendments to *IAS 1* in response to concerns raised about these changes to the classification of liabilities as current or non-current.

The new amendments clarify that covenants of loan arrangements will not affect classification of a liability as current or non-current at the reporting date if the entity must only comply with the covenants after the reporting date. However, if the entity must comply with a covenant either before or at the reporting date, this will affect the classification as current or non-current, even if the covenant is only tested for compliance after the reporting date.

The amendments were previously due to be effective for annual reporting periods beginning on or after January 1, 2023, but were subsequently deferred to periods on or after January 1, 2024, with early adoption permitted. These amendments must be applied retrospectively. The Commission has determined that amendments will not have a material impact to APMC's financial statements.

6. CASH AND CASH EQUIVALENTS

Cash and cash equivalents as at March 31, 2024 was $28.7 million (March 31, 2023 - $45.3 million). Cash and cash equivalents consist of deposits in a cash pooling structure managed by Alberta Treasury Board & Finance ("TB&F") to provide competitive interest income while maintaining appropriate security and liquidity of depositors’ capital. For the year ended March 31, 2024, the Commission earned $0.3 million (year ended March 31, 2023 - $0.6 million).

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7. RESTRICTED CASH

Restricted cash, including cash and cash equivalents, as at March 31, 2024 was $54.1 million (March 31, 2023 – $76.6 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.

Excess trust account funds at the Sturgeon Refinery are invested in low-risk, liquid short-term investments, with no longer than a 90 day term to maturity. For the year ended March 31, 2024, the short-term investments earned $4.3 million (year ended March 31, 2023 - $1.2 million).

8. ACCOUNTS RECEIVABLE

($000s)	**March 31, 2024**	March 31, 2023
Accounts receivable	**548,059**	481,450
Credit loss provision (note 19)	**(1,678)**	(18,012)
Balance, end of year	**546,381**	463,438

Accounts receivable is comprised of receivables from crude oil royalty marketing activities on behalf of the Province and receivables from Sturgeon Refinery product sales.

As at March 31, 2024, there was $198.6 million (March 31, 2023 – $183.9 million) of accounts receivable for marketing transaction activities primarily for the March 2024 delivery month, which was settled in cash on April 25, 2024. In addition, there was $347.7 million (March 31, 2023 – $279.5 million) of accounts receivable related to the Sturgeon Refinery which consisted primarily of the sale of refined products delivered in March 2024. The settlement terms related to the sale of refined products are not greater than net 21 days.

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9. INVENTORY

($000s)	**March 31, 2024**	March 31, 2023
Current		
Balance, beginning of year	**70,607**	95,704
Additions	**1,919,118**	1,859,051
Cost of sales	**(1,917,715)**	(1,884,148)
Balance, end of year – current portion	**72,010**	70,607
Long term		
Balance, beginning of year	**6,877**	6,877
Additions	**—**	—
Balance, end of year – long-term portion	**6,877**	6,877

Product inventory is comprised of synthetic crude oil, intermediate products, ultra-low sulphur diesel, unconverted oil, diluent and sulphur. As at March 31, 2024 there was $72.0 million (March 31, 2023 - $70.6 million) of hydrocarbon inventory classified as current as the Commission expects to sell it within the next twelve months of the financial reporting period.

As at March 31, 2024 there was $6.9 million (March 31, 2023 - $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.

10. INVESTMENT IN KXL EXPANSION PROJECT

On June 9, 2021, the APMC 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 $1.035 billion on behalf of the TC Energy 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 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 TC Energy 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 TC Energy 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 TC Energy. 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 be 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.

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A reconciliation of the change in the KXL Expansion Project investment is as follows:

($000s)	**March 31, 2024**	March 31, 2023
Balance, beginning of year	**33,000**	82,000
Liquidation proceeds on Class C interests	**(8,924)**	(63,770)
Foreign exchange	**(60)**	5,716
Net change in fair value	**(14,273)**	9,054
Balance, end of year	**9,743**	33,000

The fair value of the KXL Investment as at March 31, 2024 and 2023 was estimated using a market approach to value Keystone XL pipeline assets under an abandonment scenario incorporating inputs for the estimated realizable value of the assets. For the year ended March 31, 2024, the Commission incurred a loss of $14.3 million (March 31, 2023: $9.1 million gain) on the estimated fair value of its Investment in the KXL Expansion Project.

The determination of the fair value estimate included significant unobservable inputs (fair value measurement hierarchy – level 3). Estimated cash inflows and outflows are calculated based on 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 used in the determination of the estimated fair value of the KXL assets. As a result, the estimated fair value will be impacted by events after the reporting period.

On February 9, 2022, the APMC, on behalf of the GOA, filed a Notice of Intent as a formal step in preparation for a claim against the United States of America over the cancellation of the presidential permit for the Keystone XL pipeline. On April 27, 2023, the APMC, filed a Notice of Arbitration to formally initiate the arbitration claim. The action is a legacy North American Free Trade Agreement claim under the new Canada-United States Mexico Agreement. An arbitration panel was formally constituted on December 3, 2023 and initial procedural orders were settled in December 2023 and February 2024. On April 16, 2024, APMC filed its Memorial on the Merits and Quantum, which claims not less than approximately $1.6 billion in damages related to APMC's investment in the cancelled KXL pipeline.

11. INVESTMENT IN NORTH WEST REDWATER PARTNERSHIP

On June 30, 2021, the Alberta Petroleum Marketing Commission and certain of its subsidiaries (collectively, "APMC") acquired a 50 percent equity investment in NWRP. The other 50 percent interest holder in NWRP is CNR (Redwater) Limited, a wholly-owned subsidiary of CNRL.

The table below summarizes the change in the investment in NWRP joint venture:

($000s)	**March 31, 2024**	March 31, 2023
Balance, beginning of year	**230,324**	250,601
APMC's share of income (loss) from the investment in NWRP	**28,844**	(20,277)
Balance, end of year	**259,168**	230,324

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The table below presents the net income (loss) from the NWRP joint venture:

	Years ended March 31,	
($000s)	**2024**	2023
APMC's share of income (loss) from the investment in NWRP	**28,844**	(20,277)
Adjustments to NWRP license fee provision	**(41,860)**	117,638
Income (loss) from North West Redwater Partnership	**(13,016)**	97,361
Finance costs	**(5,140)**	(7,420)
Net income (loss) and comprehensive income (loss)	**(18,156)**	89,941

Summarized financial information of the joint venture, based on its IFRS financial statements adjusted to reflect APMC's accounting policies, and reconciliation with the carrying amount of the investment is as follows:

($000s)	**March 31, 2024**	March 31, 2023
Current assets, including cash and cash equivalents of $574 (March 31, 2023 - $nil)	**430,999**	292,718
Non-current assets	**11,004,645**	11,226,974
Short term borrowings	**(76,375)**	(64,366)
Other current liabilities[1]	**(858,619)**	(804,747)
Long term debt[2]	**(10,248,362)**	(10,473,454)
Other non-current liabilities	**(1,024,976)**	(1,007,501)
Deficit - 100%	**(772,688)**	(830,376)
APMC's share - 50%	**(386,344)**	(415,188)
Goodwill	**645,512**	645,512
APMC's carrying amount of the investment	**259,168**	230,324

1. As at March 31, 2024, other current liabilities included bank indebtedness of $nil million (March 31, 2023 - $103 million). One of the senior secured notes, Series A of $500 million, will mature on July 22, 2024; and $89 million of credit facility will be due June 25, 2024. These amounts have been included in other current liabilities.
2. As at March 31, 2024, long term debt of NWRP consisted of senior secured notes of $7.7 billion and $2.5 billion outstanding under the credit facility (March 31, 2023 - $8.3 billion and $2.2 billion, respectively). As at March 31, 2024, the weighted average interest rate on all senior secured notes amounts outstanding was 3.54 percent (March 31, 2023 - 3.40 percent).

Summarized statement of income (loss) of NWRP is as follows:

	Years ended March 31,	
($000s)	**2024**	2023
Revenue from Tollpayers[1]	**1,336,662**	1,206,330
Net income (loss) and comprehensive income (loss) for the year[2,3]	**57,687**	(40,553)
APMC's share of net income (loss) for the year	**28,844**	(20,277)

1. Included in NWRP's revenue for the year ended March 31, 2024 is $1,002 million representing the Commission's 75 percent share of the refining toll adjusted to reflect APMC's accounting policies (year ended March 31, 2023 - $905 million).
2. Included in the net income (loss) for the year ended March 31, 2024 is revenue recognized with respect to carbon offset credits of $214.5 million (year ended March 31, 2023 - $52.2 million).
3. Included in the net income (loss) for the year ended March 31, 2024 is the impact of depreciation and amortization expense of $410.0 million (year ended March 31, 2023 - $304.2 million), and finance costs of $427.3 million (year ended March 31, 2023 - $362.4 million).

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12. INTANGIBLE ASSETS

($000s)	**March 31, 2024**	March 31, 2023
Cost:		
Balance, beginning and end of year	**10,644**	10,644
Accumulated depreciation and amortization:		
Balance, beginning of year	**(3,992)**	(2,927)
Depreciation and amortization	**(1,064)**	(1,065)
Balance, end of year	**(5,056)**	(3,992)
Net book value, end of year	**5,588**	6,652

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. 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.

13. ACCOUNTS PAYABLE

($000s)	**March 31, 2024**	March 31, 2023
Trade payables	**121,767**	123,159
Accrued liabilities	**351,610**	265,950
Balance, end of year	**473,377**	389,109

Accounts payable and accrued liabilities are comprised of payables from marketing transactions and from Sturgeon Refinery activities.

As at March 31, 2024, there was $39.1 million (March 31, 2023 – $26.4 million) of payables for marketing activities primarily for the March 2024 delivery month, which were cash settled on April 25, 2024, as well as for general and administrative expenses.

In addition, there was $434.3 million (March 31, 2023 – $362.7 million) of accounts payable and accrued liabilities related to Sturgeon Refinery activities consisting of purchase of Refinery feedstock, and processor tolls for the March 2024 delivery month. The purchases of Refinery feedstock were settled on April 25, 2024. The processor tolls are net settled against refined product sales proceeds on April 25, 2024.

14. DUE TO THE DEPARTMENT OF ENERGY AND MINERALS

($000s)	**March 31, 2024**	March 31, 2023
Balance, beginning of year	**211,359**	218,949
Amount to be transferred	**2,116,285**	2,821,783
Amount remitted	**(2,132,922)**	(2,829,373)
Balance, end of year	**194,722**	211,359

The Commission acts as agent of the Crown in accepting delivery of and managing the Crown's royalty share of hydrocarbons. The Commission remits net crude oil royalty-in-kind net revenue to the Crown on a monthly basis.

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15. DEBT

Treasury Board & Finance ("TB&F") borrowings:

The Commission entered into a Lending and Borrowing Agreement ("Agreement") with the GOA effective April 1, 2014, which was subsequently amended April 1, 2023. The Agreement provides the framework under which APMC may, from time to time, request the GOA lend money to the APMC. The APMC must obtain an Order in Council (approved by the Lieutenant Governor in Council) to authorize the lending and borrowing dollar limits. Treasury Board & Finance ("TB&F") is the government unit responsible for lending on behalf of the GOA. The Commission has two Order in Councils; one for the Sturgeon Refinery and another for the KXL Expansion Project.

The Sturgeon Refinery Order in Council allows the Commission to borrow up to $2.9 billion for funding related to the Sturgeon Refinery. The borrowing capacity for the Sturgeon Order in Council was increased from $1.8 billion on December 9, 2023. The Commission draws on the Sturgeon Order in Council monthly, to pay Sturgeon Refinery cash shortfalls and for temporary funding to purchase feedstock. Cash received from the Sturgeon Refinery at the end of the month is used to repay borrowings.

The KXL Expansion Project Order in Council allows the Commission to borrow up to $2.0 billion for the Investment of the KXL Expansion Project. The Commission draws on the KXL Expansion Project Order in Council to pay for debt service costs. Cash received from liquidation proceeds are used to repay borrowings.

The weighted average interest rate for the year ended March 31, 2024 was 4.5 percent (year ended March 31, 2023 - 3.7 percent).

Short term debt

($000s)	Sturgeon Refinery	KXL Expansion Project	Total
Balance, March 31, 2022	1,054,532	976,895	2,031,427
Draws	2,161,464	330,742	2,492,206
Exchanged short term debt for long term bond	(668,120)	(299,297)	(967,417)
Repayments	(1,955,644)	(359,913)	(2,315,557)
Balance, March 31, 2023	**592,232**	**648,427**	**1,240,659**
Draws	**357,787**	**57,504**	**415,291**
Repayments	**(145,247)**	**(14,792)**	**(160,039)**
Balance, March 31, 2024	**804,772**	**691,139**	**1,495,911**

As at March 31, 2024, the Sturgeon Refinery's and KXL Expansion Project's short term debt includes tranches of borrowing repayable over various interest rates and terms, not exceeding one year.

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Long term debt

($000s)	Sturgeon Refinery	KXL Expansion Project	Total
Balance, March 31, 2022	—	427,493	427,493
Exchanged short term debt for long term bond	668,120	299,297	967,417
Amortization of premium on long term debt	(6,496)	(10,022)	(16,518)
Balance, March 31, 2023	**661,624**	**716,768**	**1,378,392**
Amortization of discount (premium) on long term debt	**2,409**	**(8,894)**	**(6,485)**
Total long term debt	**664,033**	**707,874**	**1,371,907**
Less current portion of long term debt	**—**	**(409,509)**	**(409,509)**
Balance, March 31, 2024	**664,033**	**298,365**	**962,398**

As at March 31, 2024, long term debt consists of the following bonds:

	Issue Date	Maturity Date	Coupon	Face value
Sturgeon Refinery				
	July 5, 2022	June 1, 2033	4.15 percent	$300,000
	November 14, 2022	June 1, 2052	2.95 percent	$500,000
KXL Expansion Project				
	July 5, 2022	June 1, 2033	4.15 percent	$300,000
	July 16, 2021	June 1, 2024	3.10 percent	$408,000

16. ACCRUED INTEREST PAYABLE

($000s)	March 31, 2024	March 31, 2023
Accrued interest on TB&F short term debt	**13,611**	10,062
Accrued interest on TB&F long term debt	**17,432**	17,421
Balance, end of year	**31,043**	27,483

17. LICENSE FEE PROVISION

($000s)	March 31, 2024	March 31, 2023
Balance, beginning of year	**87,000**	197,218
Accretion expense	**5,140**	7,420
Change in estimate	**41,860**	(117,638)
Balance, end of year	**134,000**	87,000

In connection with APMC's acquisition of a 50 percent equity interest in NWRP (note 11), APMC recognized a provision for contingent consideration associated with a licensing fee. NWRP has an agreement with NWU LP to utilize certain CO2 capture technologies in exchange for a licensing fee based on the quantity of CO2 captured from the Refinery.

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 certain economic criteria; and 3) the calculation of a net

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present value of the license fee payments are discounted using a credit adjusted risk free rate of 5.05 percent as at March 31, 2024 (March 31, 2023 – 5.78 percent).

18. STURGEON REFINERY PROCESSING AGREEMENT PROVISION

As at March 31, 2024, 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 50 percent partnership interest in NWRP.

In connection with APMC's equity investment in NWRP, on June 30, 2021, certain components of the Refinery tolls were eliminated. In addition, the interest rate on NWRP's term debt was renegotiated, reducing the debt components of the Refinery toll. The expected net economic benefits have also increased as a result of the cash flows which APMC will realize from the Processing Agreement as a 50 percent partner in NWRP.

As at March 31, 2024, the Commission recognized a non-cash $1.263 billion charge to the onerous contract provision due to lower forecasted crack spreads and recorded related accretion expense of $56.9 million (2023 - $29.8 million) resulting in an ending provision of $1.989 billion. By comparison, as at March 31, 2023, the Commission recognized a non-cash charge of $289.3 million as a result of forecasted increases in interest rates, resulting in a net $669.0 million provision.

The undiscounted future cash net inflows are estimated to be $8.6 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 years ended March 31, 2024 and March 31, 2023, the movement in the Sturgeon Refinery Processing Agreement provision is as follows:

($000s)	**March 31, 2024**	March 31, 2023
Balance, beginning of year	669,000	350,000
Change in loss provision	1,263,135	289,250
Accretion expense (note 26)	56,865	29,750
	1,989,000	**669,000**
Less: current portion	**(231,800)**	—
Balance, end of year	**1,757,200**	**669,000**

APMC uses the GOA budgeted commodity price forecast for WTI, Western Canadian Select ("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 US$/Cdn$ foreign exchange rates by decreasing them by 5 percent. The onerous contract provision would decrease by $216 million if, with all other variables held constant, the forecasted WTI-WCS differential and US$/Cdn$ foreign exchange rates decreased by 5 percent.

Changes to interest rates also impact the future cash flows under the contract. The onerous contract would increase by $66 million if, with all other variables held constant, the forecasted interest rates increased by 50 basis points.

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19. FINANCIAL INSTRUMENTS

The Commission's financial instruments consist of cash and cash equivalents, restricted cash, accounts receivable, Investment in KXL Expansion Project, accounts payable and accrued liabilities, due to EM, short term debt, accrued interest on short term debt, long term debt, license fee provision and lease obligations. Except for the Investment in KXL Expansion Project, long term debt, license fee provision, and lease obligations, the carrying values of the Commission's financial instruments approximate the fair value due to the short term nature of these instruments. Refer to note 3 for further information related to the Commission's accounting policies related to *IFRS 9 – Financial Instruments.*

($000s)		March 31, 2024		March 31, 2023	
	Hierarchy	Carrying amount	Fair value	Carrying amount	Fair value
Financial assets:					
Cash and cash equivalents	Level 1	**28,711**	**28,711**	45,337	45,337
Restricted cash	Uncategorized[1]	**54,123**	**54,123**	76,633	76,633
Accounts receivable	Uncategorized[1]	**546,381**	**546,381**	463,438	463,438
Investment in KXL Expansion Project	Level 3	**9,743**	**9,743**	33,000	33,000
Financial liabilities:					
Accounts payable and accrued liabilities	Uncategorized[1]	**473,377**	**473,377**	389,109	389,109
Due to EM	Uncategorized[1]	**194,722**	**194,722**	211,359	211,359
Short term debt	Uncategorized[1]	**1,495,911**	**1,495,911**	1,240,659	1,240,659
Accrued interest on short term debt	Uncategorized[1]	**31,043**	**31,043**	27,483	27,483
Long term debt	Level 2	**1,371,907**	**1,396,866**	1,378,392	1,430,654
License fee provision	Level 3	**134,000**	**134,000**	87,000	87,000
Lease obligations	Uncategorized[1]	**425**	**425**	438	438

1. Carrying value approximates fair value due to the short term of this instrument.

The Commission is exposed to a variety of financial risks: 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 due to 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 interest charged on the floating rate portions of its short term debt. As Tollpayer, the Commission is also exposed to interest rate risk on the floating rate portions of the debt held by NWRP. If interest rates applicable to floating rate debt increased by 1%, it is estimated that the Commissions earnings would decrease by $34.3 million.

The Commission manages its exposure to interest rate risk through the use of long term fixed rate 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 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.

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The Commission manages its exposure to credit risk on cash and cash equivalents by placing these financial instruments within a cash pooling structure maintained by TB&F (note 6).

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 from conventional crude oil marketing would be costs of APMC that would be recoverable from the EM through the marketing fee.

Credit loss provision

	Years ended March 31,	
($000s)	**2024**	2023
Accounts receivable – trade		
Balance, beginning of year	**609**	452
Change to loss provision	**734**	157
Balance, end of year	**1,343**	609
Accounts receivable – Sturgeon Refinery		
Balance, beginning of year	**17,403**	500
Receivables written off during the year	**(18,438)**	—
Change to loss provision	**1,370**	16,903
Balance, end of year	**335**	17,403
Total change to loss provision for the year	**2,104**	17,060

The loss provision for trade accounts receivable was recorded to General and Administrative Expenses in the Consolidated Statement of Loss and Comprehensive Loss. The loss provision for Sturgeon Refinery accounts receivable has been recorded to Change in Sturgeon Refinery credit loss provision in the Consolidated Statement of Loss and Comprehensive 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, 2024, excluding short term debt, the Commission's non-derivative financial liabilities with contractual maturities (including interest payments where applicable) are summarized below.

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($000s)	Total	< 1 Year	1-3 Years	3-5 Years	More than 5 Years
Accounts payable and accrued liabilities	473,377	473,377	—	—	—
Due to the Department of Energy and Minerals	194,722	194,722	—	—	—
Long term bonds - KXL Expansion Project[1]	708,000	408,000	—	—	300,000
Interest on KXL Expansion Project bonds	124,599	18,774	24,900	24,900	56,025
Long term bonds - Sturgeon Refinery[1]	800,000	—	—	—	800,000
Interest on Sturgeon Refinery bonds	538,650	27,200	54,400	54,400	402,650
Sturgeon Refinery Processing Agreement provision[2]	1,989,000	231,800	—	—	1,757,200
Lease liabilities	425	61	125	128	111
License fee provision	134,000	—	6,000	8,000	120,000
Total financial liabilities	**4,962,773**	**1,353,934**	**85,425**	**87,428**	**3,435,986**

1. Represents the face value due at maturity.
2. The amount more than 5 years represents the discounted present value of estimated net cash outflows 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 estimation of the net cash flows of the Processing Agreement used in the assessment of the onerous contract provision. As at March 31, 2024, 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 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 Investment in KXL Expansion Project. 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.

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 borrowing capacity available 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 EM 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 given the current economic environment with increased inflationary pressures and has converted a portion of short term borrowings into longer maturity borrowings (note 15).

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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 in Councils over the next twelve months.

20. COMMITMENTS

The estimated NWRP tolls under the Processing Agreement are as follows for future years ended:

(In $ millions)	March 31, 2025	March 31, 2026	March 31, 2027	March 31, 2028	March 31, 2029	Beyond 2029	Total
NWRP Tolls	1,026	1,035	821	838	940	32,667	37,327

Under the Processing Agreement, the Commission is obligated to pay a monthly toll comprised of debt principal repayment, debt service costs 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 a 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). 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)	March 31, 2025	March 31, 2026	March 31, 2027	March 31, 2028	March 31, 2029	Beyond 2029	Total
Office lease and parking [1,2]	462	463	461	452	452	753	3,043

1. Includes estimates for annual operating costs and property taxes.
2. Includes expected renewals consistent with those utilized to determine right-of-use asset and lease obligation.

The office lease has been capitalized as a right-of-use-asset and is with a related party as detailed in note 21.

21. RELATED PARTY TRANSACTIONS

The EM 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 Loss and Comprehensive Loss. The total amounts owing to the EM have been disclosed in note 14.

The Commission enters into transactions with the EM, a related party, in the normal course of business. For the year ended March 31, 2024, the Commission reimbursed the EM for salary costs of EM employees shared with the Commission, as recognized under wages and benefits, for $1.2 million (year ended March 31, 2023 - $1.3 million) within the Consolidated Statement of Loss and Comprehensive Loss.

Technology and Innovation (formerly Service Alberta), a related party providing software and maintenance services totaling $0.6 million for the year ended March 31, 2024 (year ended March 31, 2023 - $0.6 million). These expenditures were recognized within the Consolidated Statement of Loss and Comprehensive Loss.

The Commission has a sublease agreement for office premises with the Alberta Energy Regulator (the "AER"), a related party. For the year ended March 31, 2024, the APMC paid $0.4 million (year ended March 31, 2023 - $0.4 million) to the AER for office rent and parking, shared services, and leasehold improvements.

The Commission has outstanding short term debt and long term debt with TB&F (note 15).

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Summarized financial information for NWRP is found in note 11. Refer to note 4(b) for a description of the Sturgeon Refinery, note 4(c) for the NWRP monthly toll commitment and note 18 for the Sturgeon Refinery Processing Agreement Provision.

The Board members of the Commission, executive management and their close family members are deemed related parties of the Commission under IFRS. Compensation for Board members and executive management is disclosed in note 25.

22. REFINERY SALES

Pursuant to the Processing Agreements, NWRP processes bitumen and sells the refined products on behalf of the Tollpayers. As Tollpayer the Commission has a 75 percent interest in the revenues from the Sturgeon refinery. For the year ended March 31, 2024, the Commission earned $1.6 billion from two customers (year ended March 31, 2023 - $1.9 billion from three customers).

23. TURNAROUND EXPENDITURES

The Commission paid $1.5 million (2023 - $164.3 million) to NWRP for tolls related to turnaround costs. As the Commission has recognized an onerous contract provision at March 31, 2024 and March 31, 2023, the tolls related to turnaround costs have been expensed as incurred and not recognized as a prepaid expense.

24. GENERAL AND ADMINISTRATIVE EXPENSES

	Years ended March 31,	
($000s)	**2024**	2023
Wages and benefits	**7,304**	6,607
Consulting	**3,742**	2,711
Software and maintenance	**929**	1,195
Office rent and property taxes	**359**	344
Dues and subscriptions	**257**	254
Director fees	**100**	106
Change in loss provision for accounts receivable	**734**	157
Other	**318**	186
Total general and administrative expenses	**13,743**	11,560

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25. KEY MANAGEMENT COMPENSATION

Key management personnel include the Commission's Board Members, Chief Executive Officer, Chief Financial Officer, General Counsel, Vice President, Operations and Vice President, Business Development and Marketing. The amounts relating to board members and key management compensation for the years ended March 31, 2024 and 2023 are as follows:

	Years ended March 31,	
($000s)	**2024**	2023
Base salary	**1,540**	1,377
Other short term benefits[1]	**344**	313
Director fees[2]	**92**	108
Total key management compensation	**1,976**	1,798

1. As per their employment contracts, the key management personnel receive cash payments in lieu of retirement benefits, as well as perquisites such as parking. There is no bonus program as part of the Commission's compensation.
2. The Chair of the Board (Deputy Minister, EM) and one director (Assistant Deputy Minister, EM) are unpaid. There are five independent Board Members. The independent Board Members receive annual retainer and meeting fees.

26. FINANCE COSTS

Finance costs consist of the following:

($000s)	**March 31, 2024**	March 31, 2023
Accretion Expense - license fee provision (note 17)	**5,140**	7,420
Amortization of premium on long term debt (note 15)	**(6,485)**	(16,518)
Accretion Expense - Sturgeon Refinery Processing Agreement Provision (note 18)	**56,865**	29,750
Interest Expense	**119,120**	80,840
Total finance costs	**174,640**	101,492

27. INCOME TAXES

The Commission is exempt from Canadian federal and provincial corporate income taxes. However, 2254746 Alberta Sub Ltd. (the "US subsidiary"), a Delaware incorporated company, and 2254746 Alberta Ltd. (the "Canadian holding company"), an Alberta incorporated company, have exposure to US federal and state corporate income taxes.

Through the tax year ended December 31, 2022, the US subsidiary has estimated US net operating losses for income tax purposes of US$383 million, which carry forward indefinitely. The IRS completed their review of US tax returns for the tax year ended December 31, 2021 and they concluded that business losses resulting from the liquidation of KXL assets in the US partnership could be utilized against previously recorded accretion income and withholding taxes paid on inter-corporate dividends paid to the Canadian holding company. As a result, the IRS issued a refund of $5.6 million (US$4.1 million) for previously paid taxes. The income tax recovery was not booked until the year ended March 31, 2024 as it was uncertain that the taxes would be recoverable.

The Commission does not currently have any deferred income tax assets or liabilities.

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28. SUPPLEMENTAL CASH FLOW

Details of changes in non-cash working capital from operating activities include the following:

	Year Ended	
	Years ended March 31,	
($000s)	**2024**	2023
Restricted cash	**22,510**	(4,065)
Accounts receivable	**(66,609)**	175,543
Inventory	**(1,403)**	25,097
Accounts payable and accrued liabilities	**84,268**	(159,201)
Due to the Department of Energy and Minerals	**(16,637)**	(7,590)
Changes in non-cash working capital from operating activities	**22,129**	29,784

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29. SEGMENT INFORMATION

These reportable segments of the APMC 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 APMC's executive leadership team 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'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 Oil 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. As a result, the APMC provides financial information on revenues and expenses of each segment, but not total assets or liabilities by segment.

<u>*Years ended March 31, 2024 and 2023*</u>

	Conventional Crude Oil Marketing		Sturgeon Refinery (Tollpayer)		NWRP Joint Venture (Refinery Owner)		KXL Expansion Project		Total	
($000s)	**2024**	2023	**2024**	2023	**2024**	2023	**2024**	2023	**2024**	2023
REVENUES										
Refinery sales	**—**	—	**2,669,457**	2,733,082	**—**	—	**—**	—	**2,669,457**	2,733,082
Marketing fee income	**14,585**	12,050	**—**	—	**—**	—	**—**	—	**14,585**	12,050
	14,585	12,050	**2,669,457**	2,733,082	**—**	—	**—**	—	**2,684,042**	2,745,132
Finance income	**30**	129	**4,442**	2,451	**—**	—	**147**	—	**4,619**	2,580
	14,615	12,179	**2,673,899**	2,735,533	**—**	—	**147**	—	**2,688,661**	2,747,712
EXPENSES										
Refinery feedstock purchases	**—**	—	**1,917,715**	1,884,148	**—**	—	**—**	—	**1,917,715**	1,884,148
Refinery tolls	**—**	—	**930,666**	878,508	**—**	—	**—**	—	**930,666**	878,508
Turnaround expenditures	**—**	—	**1,498**	164,279	**—**	—	**—**	—	**1,498**	164,279
General and administrative	**13,324**	10,735	**158**	374	**—**	—	**261**	451	**13,743**	11,560
Depreciation and amortization	**1,174**	1,166	**—**	—	**—**	—	**—**	—	**1,174**	1,166
Loss (gain) on foreign exchange	**111**	21	**51**	(78)	**—**	—	**118**	(5,745)	**280**	(5,802)
Finance costs	**6**	6	**121,278**	63,782	**5,140**	7,420	**48,216**	30,284	**174,640**	101,492
Loss (Income) from North West Redwater Partnership	**—**	—	**—**	—	**13,016**	(97,361)	**—**	—	**13,016**	(97,361)
Sturgeon Refinery Processing Agreement	**—**	—	**1,263,135**	289,250	**—**	—	**—**	—	**1,263,135**	289,250
Credit loss provision	**—**	—	**1,370**	16,903	**—**	—	**—**	—	**1,370**	16,903
Fair value loss (gain) on investment in KXL Expansion Project	**—**	—	**—**	—	**—**	—	**14,273**	(9,054)	**14,273**	(9,054)
Total expenses	**14,615**	11,928	**4,235,871**	3,297,166	**18,156**	(89,941)	**62,868**	15,936	**4,331,510**	3,235,089
Net income (loss) and comprehensive income (loss) before income taxes	**—**	251	**(1,561,972)**	(561,633)	**(18,156)**	89,941	**(62,721)**	(15,936)	**(1,642,849)**	(487,377)
Income tax recovery	**—**	—	**—**	—	**—**	—	**(5,576)**	—	**(5,576)**	—
Net income (loss) and comprehensive income (loss) after income taxes	**—**	251	**(1,561,972)**	(561,633)	**(18,156)**	89,941	**(57,145)**	(15,936)	**(1,637,273)**	(487,377)

Post-Closure Stewardship Fund

Financial Statements

For the Year Ended March 31, 2024

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Independent Auditor’s Report

Auditor General OF ALBERTA

To the Minister of Energy and Minerals

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, 2024, 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, 2024, 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 and Minerals.* The other information comprises the information included in the *Annual Report of the Ministry of Energy and Minerals* 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 and Minerals* 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]
W. Doug Wylie FCPA, FCMA, ICD.D
Auditor General

June 6, 2024
Edmonton, Alberta

Statement of Operations

Post-Closure Stewardship Fund
Year Ended March 31, 2024
(in thousands)

	2024		2023
	Budget	Actual	Actual
Revenue			
Injection Levy (Note 3)	$ 230	$ 587	$ 447
Investment Income	-	99	51
Net Operating Results	230	686	498

The accompanying notes are part of these financial statements.

Statement of Financial Position

Post-Closure Stewardship Fund
As of March 31, 2024
(in thousands)

	2024	2023
Assets		
Cash (Note 4)	$ 2,532	$ 1,830
Accounts Receivable	323	339
Net Financial Assets	**$ 2,855**	**$ 2,169**
Net Financial Assets at Beginning of Year	$ 2,169	$ 1,671
Annual Operating Results	686	498
Net Financial Assets at End of Year	**$ 2,855**	**$ 2,169**

The accompanying notes are part of these financial statements.

Statement of Change in Net Financial Assets

Post-Closure Stewardship Fund
Year Ended March 31, 2024
(in thousands)

	2024		2023
	Budget	Actual	Actual
Annual Operating Results	$ 230	$ 686	$ 498
Increase in Net Financial Assets	$ 230	$ 686	$ 498
Net Financial Assets at Beginning of Year	-	2,169	1,671
Net Financial Assets at End of Year	**$ 230**	**$ 2,855**	**$ 2,169**

The accompanying notes are part of these financial statements.

Statement of Cash Flows

Post-Closure Stewardship Fund
Year Ended March 31, 2024
(in thousands)

	2024	2023
Operating Transactions		
Net Operating Results	$ 686	$ 498
Decrease (Increase) in Accounts Receivable	16	(229)
Increase in Cash and Cash Equivalents	**$ 702**	**$ 269**
Cash and Cash Equivalents at Beginning of Year	1,830	1,561
Cash and Cash Equivalents at End of Year	**$ 2,532**	**$ 1,830**

The accompanying notes are part of these financial statements.

Notes to Financial Statements

Post-Closure Stewardship Fund
March 31, 2024

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.

(b) **Change in Accounting Policy**
Effective April 1, 2023, the Fund adopted the PS 3400 Revenue standard. There were no changes to the measurement of revenues on adoption of the new standard.

At the beginning of the same fiscal reporting period, PSG-8 Purchased Intangibles Guidelines and PS 3160 Public Private Partnerships also came into effect. The new standard and guideline did not have any impact on the Fund’s financial statements.

(c) **Future Changes in Accounting Standards**
On April 1, 2026, the Fund will adopt the following new conceptual framework and accounting standard approved by the Public Sector Accounting Board.

The Conceptual Framework for Financial Reporting in the Public Sector
The Conceptual Framework is the foundation for public sector financial reporting standard setting. It replaces the conceptual aspects of Section PS 1000 Financial Statement Concepts and Section PS 1100 Financial Statement Objectives. The conceptual framework highlights considerations fundamental for the consistent application of accounting issues in the absence of specific standards.

PS 1202 Financial Statement Presentation
Section PS 1202 sets out general and specific requirements for the presentation of information in general purpose financial statements. The financial statement presentation principles are based on the concepts within the Conceptual Framework.

Notes to Financial Statements

Post-Closure Stewardship Fund
March 31, 2024

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, 2024, there is only one approved carbon dioxide injection site. The most recent estimated present value cost model as at the Ministerial Order date of August 16, 2022 is $10.9 million. Currently, approximately 33% 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 and cash equivalents includes demand deposits in the Consolidated Liquidity Solution (CLS). A CLS participant is paid interest on monthly basis on their cash balance at an interest rate based on 12 week rolling average of the Province’s 3 month cost of borrowing.

The fund earns interest at an effective rate of 4.95% per annum (2023 - 3.04%).

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, 2024

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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, 2024, 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 CEC as at March 31, 2024, 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.

Emphasis of matter – going concern

I draw attention to Note 1 of the financial statements; as stated in Note 1, the CEC operated on a going concern basis through March 31, 2024. On April 3, 2024, the Board of Directors passed a resolution for the CEC to cease operations. My opinion is not modified in respect of 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 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 as applicable in accordance with Canadian public sector accounting standards.

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. Because of the decision to cease operations of the CEC, as disclosed in the financial statements, it ceased to be 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]

W. Doug Wylie FCPA, FCMA, ICD.D
Auditor General

May 30, 2024
Edmonton, Alberta

Statement of Operations

Canadian Energy Centre Ltd.
Year Ended March 31, 2024

	2024		2023
	Budget (Note 5)	**Actual**	**Actual**
Revenues			
Government transfers			
Government of Alberta grants	$ -	$ -	$ 31,789,000
Other Revenue	-	20,130	537
	-	**20,130**	**31,789,537**
Expenses (Schedule 1)			
Resource Development and Management	9,100,000	8,342,328	26,058,712
	9,100,000	**8,342,328**	**26,058,712**
Annual operating (deficit)/ surplus	(9,100,000)	(8,322,198)	5,730,825
Annual (deficit)/ surplus	**(9,100,000)**	**(8,322,198)**	**5,730,825**
Accumulated surplus at beginning of year	10,248,219	10,248,219	4,517,394
Accumulated surplus at end of year (Note 9)	**$ 1,148,219**	**$ 1,926,021**	**$ 10,248,219**

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

Statement of Financial Position

Canadian Energy Centre Ltd.
As at March 31, 2024

	2024	2023
Financial Assets		
Cash	$ 1,609,879	$ 9,891,211
Accounts receivable	276,085	1,156,294
	1,885,964	**11,047,505**
Liabilities		
Accounts payable and other accrued liabilities (Note 7)	272,669	2,660,690
	272,669	**2,660,690**
Net Financial Assets	**1,613,295**	**8,386,815**
Non-Financial Assets		
Prepaid expenses (Note 8)	312,726	1,861,404
	312,726	**1,861,404**
Net Assets		
Accumulated surplus (Note 9)	**1,926,021**	**10,248,219**
	$ 1,926,021	**$ 10,248,219**

Contractual obligations (Note 11)

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

Statement of Change in Net Financial Assets

Canadian Energy Centre Ltd.
Year Ended March 31, 2024

	2024		2023
	Budget	Actual	Actual
Annual (deficit)/ surplus	$ -	$ (8,322,198)	$ 5,730,825
Decrease/ (increase) in prepaid expenses	-	1,548,678	(1,555,250)
(Increase)/ decrease in net financial assets	-	(6,773,520)	4,175,575
Net financial assets at beginning of year	8,386,815	8,386,815	4,211,240
Net financial assets at end of year	$ 8,386,815	$ 1,613,295	$ 8,386,815

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

Statement of Cash Flows

Canadian Energy Centre Ltd.
Year Ended March 31, 2024

	2024	2023
Operating transactions		
Annual (deficit)/ surplus	$ (8,322,198)	$ 5,730,825
Decrease/ (increase) in accounts receivable	880,209	(1,033,914)
Decrease/ (increase) in prepaid expenses	1,548,678	(1,555,250)
(Decrease)/ increase in accounts payable and other accrued liabilities	(2,388,021)	2,006,564
Cash (applied to) provided by operating transactions	**(8,281,332)**	**5,148,225**
(Decrease)/ increase in cash	**(8,281,332)**	**5,148,225**
Cash at beginning of year	**9,891,211**	**4,742,986**
Cash at end of year	**$ 1,609,879**	**$ 9,891,211**

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

Notes to the Financial Statements

Canadian Energy Centre Ltd.
Year Ended March 31, 2024

Note 1 AUTHORITY

The Canadian Energy Centre Ltd. (the "CEC" or the "Corporation") is a provincial corporation incorporated under the *Business Corporations Act* (Alberta) on October 9, 2019.

The Corporation is wholly owned by His Majesty the King 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.*

Through March 31, 2024, the corporation operated on a going-concern basis, which contemplated the realization of assets and discharge of liabilities in the normal course of business. The Board of Directors subsequently passed a resolution April 3, 2024 for the Corporation to cease operations. The Corporation will complete an operational closure by June 30, 2024.

An estimate of the financial effect of the complete operational closure of the corporation cannot be made at this time.

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.

<u>Government Transfers</u>

Transfers from all governments are referred to as government transfers.

Notes to the Financial Statements

Canadian Energy Centre Ltd.
Year Ended March 31, 2024

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

a. Basis of Financial Reporting (Continued)

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.

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.

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.

Notes to the Financial Statements

Canadian Energy Centre Ltd.
Year Ended March 31, 2024

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

a. Basis of Financial Reporting (Continued)

Accounts receivable

Accounts receivables 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.

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, and asset retirement cost. 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, no tangible capital assets are reported in the financial statements.

Prepaid expenses

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

Notes to the Financial Statements

Canadian Energy Centre Ltd.
Year Ended March 31, 2024

Note 3 CHANGES IN ACCOUNTING POLICY

Effective April 1, 2023, the Corporation adopted the PS 3400 Revenue standard. There were no changes to the measurement of revenues on adoption of the new standard.

At the beginning of the same fiscal reporting period, PSG-8 Purchased Intangibles Guidelines and PS 3160 Public Private Partnerships also came into effect. The new standard and guideline did not have any impact on the Corporation's financial statements.

Note 4 FUTURE CHANGES IN ACCOUNTING STANDARDS

On April 1, 2026, the CEC will adopt the following new conceptual framework and accounting standard approved by the Public Sector Accounting Board:

- **The Conceptual Framework for Financial Reporting in the Public Sector**
  The Conceptual Framework is the foundation for public sector financial reporting standard setting. It replaces the conceptual aspects of Section PS 1000 Financial Statement Concepts and Section PS 1100 Financial Statement Objectives. The conceptual framework highlights considerations fundamental for the consistent application of accounting issues in the absence of specific standards.

- **PS 1202 Financial Statement Presentation**
  Section PS 1202 sets out general and specific requirements for the presentation of information in general purpose financial statements. The financial statement presentation principles are based on the concepts within the Conceptual Framework.
  Management is currently assessing the impact of the conceptual framework and the standard on the financial statements.

Note 5 BUDGET

The below Budget was approved by the Board for the fiscal 2024 year.

Budget		Amount	Approval Date
April 2023 – March 2024 Budget	$	12,000,000	March 01, 2023
Budget Revision		(2,900,000)	September 08, 2023
Total	**$**	**9,100,000**	

Revenue budget reported in the Statement of Operations reflects actual cash received during the year and expenses budget reported in the Statement of Operations reflects the budget.

Notes to the Financial Statements

Canadian Energy Centre Ltd.
Year Ended March 31, 2024

Note 6 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 CEC. Credit risk on accounts receivable is considered low.

As of March 31, 2024, 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 of Energy. The Corporation manages liquidity risks by its budget processes and regularly monitoring cash flows to ensure the necessary funds are on hand to fulfill upcoming obligations, including operating expenses.

Note 7 ACCOUNTS PAYABLE AND OTHER ACCRUED LIABILITIES

	2024	2023
Accounts Payable	$ 14,219	$ 1,331,479
Accrued liabilities	6,288	1,264,748
ATB Alberta Rewards Business Card	-	13,015
Accrued Salaries and Wages	9,755	12,064
Accrued Severance Pay	193,299	-
Vacation Payable	49,108	39,384
Balance at end of year	**$ 272,669**	**$ 2,660,690**

Note 8 PREPAID EXPENSES

	2024	2023
Agency of Record	$ 173,698	$ 1,729,455
Subscriptions	139,028	131,949
Balance at end of year	**$ 312,726**	**$ 1,861,404**

Notes to the Financial Statements

Canadian Energy Centre Ltd.
Year Ended March 31, 2024

Note 9 ACCUMULATED SURPLUS

Accumulated surplus is comprised of the following:

		2024		2023
Balance at beginning of year	$	10,248,219	$	4,517,394
Annual (deficit)/ surplus		(8,322,198)		5,730,825
Balance at end of year	**$**	**1,926,021**	**$**	**10,248,219**

Note 10 SHARE CAPITAL

Share capital is comprised of the following:

		2024		2023
Issued:				
1 Common Share	$	6,800	$	6,800
Balance at end of year	**$**	**6,800**	**$**	**6,800**

Note 11 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.

		2024		2023
Obligations under contracts	$	-	$	845,318
Balance at end of year	**$**	**-**	**$**	**845,318**

Note 12 APPROVAL OF FINANCIAL STATEMENTS

The Board approved the financial statements of the Corporation.

Expenses – Detailed by Object

Canadian Energy Centre Ltd.
Year Ended March 31, 2024
(Schedule 1)

	2024		2023
	Budget	**Actual**	**Actual**
Salaries and Benefits	$ 1,500,000	$ 1,615,695	$ 1,479,406
Office Infrastructure	165,000	75,655	79,130
General and Administrative Expenses	55,000	51,710	70,253
Legal	85,000	33,013	59,971
Accounting	210,000	192,000	200,000
IT	6,000	6,000	8,375
Clean Energy Regulation Campaign	1,100,000	1,100,000	-
Website	58,000	52,000	34,667
Social Advertising	500,000	453,590	696,711
Research	966,000	778,021	1,303,614
Media	150,000	98,111	162,338
Travel	10,000	5,325	-
RFP – Agency of Record	4,200,000	3,870,800	21,937,301
Sponsorship	15,000	9,950	-
Contingency – Other	80,000	458	26,946
Total Expenses	**$ 9,100,000**	**$ 8,342,328**	**$ 26,058,712**

Salary and Benefits Disclosure

Canadian Energy Centre Ltd.
Year Ended March 31, 2024
(Schedule 2)

		2024			2023
	Base Salary (1)	Other Cash Benefits (2)	Other Non-cash Benefits (3)	Total	Total
Chief Executive Officer (CEO) (4)	$ 194,252	$ 47,340	$ 5,283	$ 246,875	$ 246,750
Executive Director (5)	-	-	-	-	136,773
Executive Director (6)	72,400	17,681	4,700	94,781	-
Executive Director (7)	96,360	101,496	482	198,338	218,519
Executive Director (8)	171,600	41,904	5,182	218,686	73,662
Total Expenses	**$ 534,612**	**$ 208,421**	**$ 15,647**	**$ 758,680**	**$ 675,704**

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, phone allowance and severance. No bonuses were paid during the year.
3. Other non-cash benefits include employee benefits and contributions or payments made on behalf of employees including CPP and EI.
4. 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. Other cash benefits does not include accrued severance of $48,563. The Corporation intends on paying it upon cessation of operations in the next fiscal period.
5. 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. Last day of employment was November 11, 2022.
6. Executive Director was hired on January 20, 2020, and was promoted to current position effective October 27, 2023 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. Other cash benefits does not include accrued severance of $250 in accordance with employment cessation agreement. The amount will be paid in the next fiscal period.
7. 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. Last day of employment was October 25, 2023. Other cash benefits include severance paid of $62,243 in accordance with employment cessation agreement.
8. Executive Director was hired on December 5, 2022 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. Other cash benefits does not include accrued severance of $250 in accordance with employment cessation agreement. The amount will be paid in the next fiscal period.

Related Party Transactions

Canadian Energy Centre Ltd.
Year Ended March 31, 2024
(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:

	2024	2023
Revenues		
Grants	$ -	$ 31,789,000
	-	31,789,000
Expenses		
Rent	57,354	57,354
Insurance coverage	1,486	1,516
	58,840	58,870
Common Share - Department of Energy	$ 6,800	$ 6,800

Other Financial Information

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Lapse/Encumbrance (unaudited)

The following has been prepared pursuant to Section 24(4) of the *Financial Administration Act*.

Department of Energy and Minerals
Year Ended March 31, 2024
(in thousands)

	Voted Estimate	Supplementary Estimate	Adjustments	Adjusted Voted Estimate	Voted Actuals	Over Expended (Unexpended)
EXPENSE VOTE BY PROGRAM						
Ministry Support Services						
1.1 Minister's Office	$ 1,015	$ -	$ -	$ 1,015	$ 567	$ (448)
1.2 Deputy Minister's Office	1,048	-	-	1,048	823	(225)
1.3 Corporate Services	4,932	-	-	4,932	3,812	(1,120)
	6,995	-	-	6,995	5,202	(1,793)
Resource Development and Management						
2.1 Energy Operations	18,684	-	-	18,684	17,039	(1,645)
2.2 Energy Policy	43,100	(501)	-	42,599	34,481	(8,118)
2.3 Industry Advocacy	27,041	(2,566)	-	24,475	4,752	(19,723)
	88,825	(3,067)	-	85,758	56,272	(29,486)
Cost of Selling Oil						
3 Cost of Selling Oil	316,000	40,667	-	356,667	366,486	9,819
Economic Recovery Support						
4.1 Site Rehabilitation Program	605	-	-	605	500	(105)
4.2 Mineral Strategy	12,356	-	-	12,356	12,356	-
	12,961	-	-	12,961	12,856	(105)
CAPITAL GRANTS						
Economic Recovery Support						
4.3 Alberta Petrochemicals Incentive Program	146,800	(30,556)	-	116,244	109,433	(6,811)
Total	$ 571,581	$ 7,044	$ -	$ 578,625	$ 550,249	$ (28,376)
Credit or Recovery Shortfall			(626)	(626)		626
	571,581	7,044	(626)	577,999	550,249	(27,750)
(Lapse)/Encumbrance						$ (27,750)
CAPITAL INVESTMENT VOTE BY PROGRAM						
Ministry Support Services						
1.3 Corporate Service	1,000	-	500	1,500	543	(957)
	$ 1,000	$ -	$ 500	$ 1,500	$ 543	$ (957)
(Lapse)/Encumbrance						$ (957)

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, 2023, and March 31, 2024.