GOVERNMENT OF ALBERTA

Annual Report

Energy

2020-2021

Government of Alberta | Energy 2020-21 Annual Report

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

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Acronyms and Notations

AER	Alberta Energy Regulator
AESO	Alberta Electric System Operator
APIP	Alberta Petrochemical Incentive Program
APMC	Alberta Petroleum Marketing Commission
ARP	Alberta Natural Gas Reference Price
AUC	Alberta Utilities Commission
bbl	Barrel
bbl/d	Barrels per day
CEC	Canadian Energy Centre Limited
COVID-19	Coronavirus 2019
ER&T	Emerging Resources and Technologies Initiative
ESG	Environmental Social Governance
GJ	Gigajoule
ha	Hectare
IDA	Integrated Decision Approach
IEEP	Incremental Ethane Extraction Program
IRMS	Integrated Resource Management System
KXL	Keystone XL
LAMAS	Land Automated Mineral Agreement System
LNG	Liquefied Natural Gas
MIM	Metallic and Industrial Minerals
MINRS	Metallic and Industrial Minerals Royalty Revenues
MSA	Market Surveillance Administrator
MW	Megawatt
NGAP	Natural Gas Advisory Panel
NGDDP	Natural Gas Deep Drilling Program
NGTL	TC Energy Corporation’s NOVA Gas Transmission Ltd.
NWRP	Northwest Redwater Partnership
OPEC	Organization of the Petroleum Exporting Countries
OWA	Orphan Well Association
PDP	Petrochemicals Diversification Program
PPA	Power Purchase Agreement
REP	Renewable Electricity Program
Tcf	Trillion cubic feet
TIER	Technology Innovation and Emissions Reduction
TSP	Temporary Service Protocol
US$	United States Dollar
WCS	Western Canadian Select
WTI	West Texas Intermediate

Preface

The Public Accounts of Alberta are prepared in accordance with the *Financial Administration Act* and the *Fiscal Planning and Transparency Act*. The Public Accounts consist of the annual report of the Government of Alberta and the annual reports of each of the 21 ministries.

The annual report of the Government of Alberta contains ministers' accountability statements, the consolidated financial statements of the province and the *Measuring Up* report, which compares actual performance results to desired results set out in the government's strategic plan.

This annual report of the Ministry of Energy contains the minister's accountability statement, the financial information of the ministry and a comparison of actual performance results to desired results set out in the ministry business plan. This ministry annual report also includes:

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

Minister's Accountability Statement

The ministry's annual report for the year ended March 31, 2021, was prepared under my direction in accordance with the *Fiscal Planning and Transparency Act* and the government's accounting policies. All of the government's policy decisions as at June 4, 2021 with material economic or fiscal implications of which I am aware have been considered in the preparation of this report.

[Original signed by]

Honourable Minister Sonya Savage
Minister of Energy

Message from the Minister

Looking back on 2020-21, the year was certainly not easy – to say the least – for our energy industry. The pandemic brought new challenges to a sector already dealing with the impacts of sustained low oil prices and a global recession.

But with challenges come opportunity.

No stranger to adversity, folks in the energy sector demonstrated their resilience while finding new opportunities to move the sector forward; building on its strengths and opening doors to new and emerging resources and technologies.

Our government remained committed to helping the industry gain momentum to rise above and beyond its challenges. Furthermore, we continued to provide supports to businesses struggling in the face of the pandemic, and we introduced new programs to help protect the industry and the livelihoods of thousands of Albertans.

Shortly after the World Health Organization declared a global pandemic, the government allowed Albertans to defer their natural gas and electricity utility payments. In May, we passed the *Utility Payment Deferral Program Act* to help electricity and natural gas providers to continue to help those Albertans.

We introduced the Site Rehabilitation Program, which directs up to $1 billion of federal oil and gas relief funding to speed up well, pipeline and site closure efforts in the energy sector. Overall, the program will help create more than 5,000 direct jobs and lead to indirect employment – and economic benefits – across the province, as other businesses benefit from the increased clean up work occurring in many rural Alberta areas.

Our ongoing advocacy work to fight for our energy sector and the hard-working Albertans it employs saw some success as we pressed for the timely completion of vital pipeline projects. This included the Trans Mountain expansion project, which was about 22 per cent complete at the end of 2020, as well as on Enbridge's Line 3 replacement project. Unfortunately, we were disappointed to see the Presidential permit for Keystone XL revoked and the resulting loss of jobs for more than 2,000 people. This setback demonstrates why this advocacy will remain a crucial priority for government now and in the years to come.

We succeeded in making it easier for companies to do business in our province by reducing red tape and regulatory burden for the energy industry. The ministry has achieved 15 per cent in reductions this year, exceeding our target of 12 per cent for 2020-21. The ministry's red tape initiatives have resulted in substantial cost savings for industry, for example with the Alberta Energy Regulator's Water Disposal Enhancements project that could save industry an estimated $273 million.

We also doubled down to further Alberta's position as a leader in environmental, social and governance outcomes. We have and continue to share our story with global investors, demonstrating the critical role Alberta's vast and diverse energy resources – as well as our commitment to innovation and advancing technology play in the global energy future.

The future of energy will continue to include Alberta's energy and other mineral resources for decades to come, even as demand grows for greener sources of energy. That's why Alberta's government took a number of steps to support traditional oil and gas while also pursuing emerging opportunities.

For example, in October 2020 we released the Natural Gas Vision and Strategy, which outlined some of those opportunities for diversification in the natural gas sector. These will not only increase demand for natural gas, but expand Alberta's energy sector into new and fast-growing sectors. This strategy included the launch of the

Alberta Petrochemicals Incentive Program to encourage innovation, attract billions in investment and create thousands of jobs in Alberta's petrochemical sector. We also started the development of a hydrogen road map which will build on Alberta's experience in carbon capture, utilization and storage and our large natural gas reserves to chart out how the government can best support the emerging hydrogen economy.

Our diversification efforts will position Alberta as a destination for investment and a place with many growth opportunities. This includes continuing to tap into industry's experience in carbon capture, utilization and storage and other emerging technologies, to reduce greenhouse gas emissions while also diversifying our energy mix.

Our work also included building on Alberta's expertise in carbon capture, utilization and storage and our large natural gas reserves to begin the development of a hydrogen road map to chart out how the government can best support the emerging hydrogen economy.

In the fall, we launched the Alberta Petrochemicals Incentive Program to encourage innovation, attract billions in investment and create thousands of jobs in Alberta's petrochemical sector.

We began developing a modern minerals strategy to maximize Alberta's untapped geological potential to meet the growing demands for minerals. The strategy will help place Alberta at the forefront of global mineral exploration and development while strengthening and diversifying our economy. We also passed the *Geothermal Resource Development Act*, which establishes a clear path forward for geothermal projects.

Private industry also benefited from Alberta's commitment to our energy-only electricity market, which continued to provide stability to investors and drive competitive pricing for consumers. Since July 2019, more than $5 billion in investment has been announced for generation projects – including more than $2 billion for utility-scale renewable projects.

Finally, I would be remiss if I didn't mention the work we are doing to engage with Albertans on the province's coal policy. This spring, we appointed an independent Coal Policy Committee to lead a wide-ranging and comprehensive public engagement to inform Alberta's long-term approach to coal development.

In a year unlike any other, Albertans demonstrated their ability to not only persevere but to rise above. This was abundantly clear in the energy sector, where even while facing unprecedented challenges, Albertans found new opportunities and new approaches to continue moving the sector forward – proving, yet again, why our province continues to be a leader. I have every confidence that the year ahead will build on what we've accomplished and take us even further.

[Original signed by]

Honourable Minister Sonya Savage

Minister of Energy

Management's Responsibility for Reporting

The Ministry of Energy includes:

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

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

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

Responsibility for the integrity and objectivity of the accompanying ministry financial information and performance results for the ministry rests with the Minister of Energy. Under the direction of the Minister, as senior executives, we oversee the preparation of the ministry's annual report, including the financial information and performance results. The financial information and performance results, 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:

- **Reliability** – Information used in applying performance measure methodologies agrees with the underlying source data for the current and prior years' results.
- **Understandability** – the performance measure methodologies and results are presented clearly.
- **Comparability** – the methodologies for performance measure preparation are applied consistently for the current and prior years' results.
- **Completeness** – outcomes, performance measures and related targets match those included in the ministry's *Budget 2020*.

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

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

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

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

[Original signed by]

Grant Sprague, Q.C.
Deputy Minister of Energy

[Original signed by]
Adrian Begley
Chief Executive Officer
Alberta Petroleum Marketing Commission

[Original signed by]
Carolyn Dahl Rees
Chair
Alberta Utilities Commission

[Original signed by]
Laurie Pushor
President and Chief Executive Officer
Alberta Energy Regulator

[Original signed by]
Tom Olsen
Chief Executive Officer and Managing Director
Canadian Energy Centre Ltd.

[Original signed by]
Greg Clark
Chair
Balancing Pool

June 4, 2021

Results Analysis

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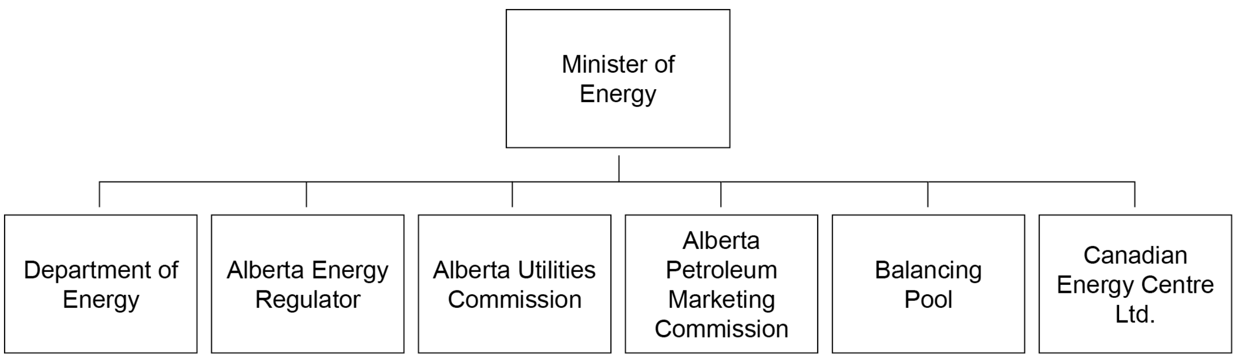
Ministry Overview

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

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

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

Organizational Structure



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

The outcomes in Energy's 2020-21 Business Plan are:

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

Department of Energy

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

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

Alberta Energy Regulator

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

Alberta Utilities Commission

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

Alberta Petroleum Marketing Commission

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

Balancing Pool

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

Canadian Energy Centre

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

Alberta's Energy Resource Sector

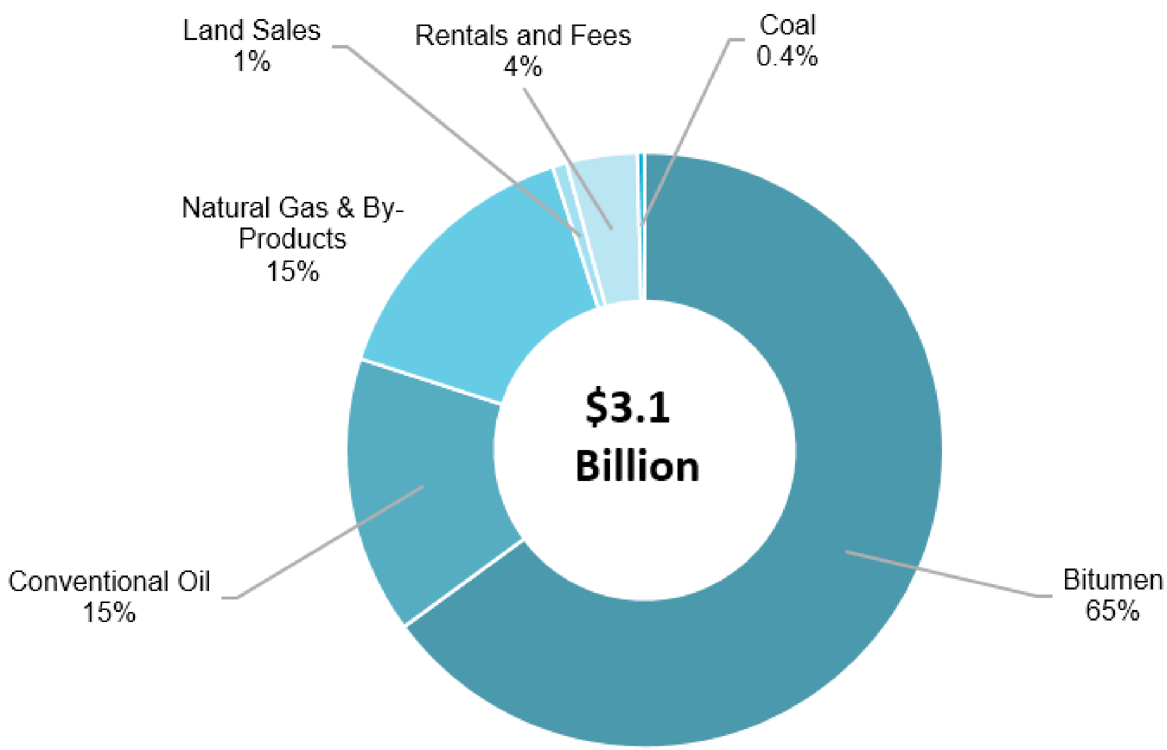
Non-Renewable Resource Revenue

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

Non-Renewable Resource Revenue Generated

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

2020-21 Non-Renewable Resource Revenue



Source: Government of Alberta

Note: Totals may not add up precisely due to rounding.

Non-renewable resource revenues totaled around $3.1 billion in the 2020-21 fiscal year, about $2.0 billion lower than the budgeted amount of $5.1 billion, and $2.85 billion lower than in 2019-20. This substantial decrease in non-renewable resource revenues was a result of significantly lower West Texas Intermediate prices for the fiscal year, which impacted the production of bitumen and conventional crude oil. Lower prices for oil also had a downward impact on gas prices and gas royalties, since prices for natural gas by-products follow oil prices. The collapse in crude demand and prices as a result of the COVID-19 pandemic and global recession had overall effects on production, employment, investment and drilling.

Factors Impacting Non-Renewable Resource Revenue

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

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

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

Commodity Prices and Trends[i]

Commodity Prices	2020-21 Budget	2020-21 Actual
WTI (US$/bbl)	58.00	42.32
Exchange rate	76.50	75.75
Light-Heavy differential (US$/bbl)	19.10	10.58
WCS (US$/bbl)	38.90	31.74
Alberta reference price for natural gas (Cdn$/GJ)	1.70	2.10

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

Oil Prices

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

Oil prices remained weak in 2020-21, as expanding global COVID-19 cases threaten economic recovery and the speed of demand growth, even though global producers continue to exercise supply curtailment.

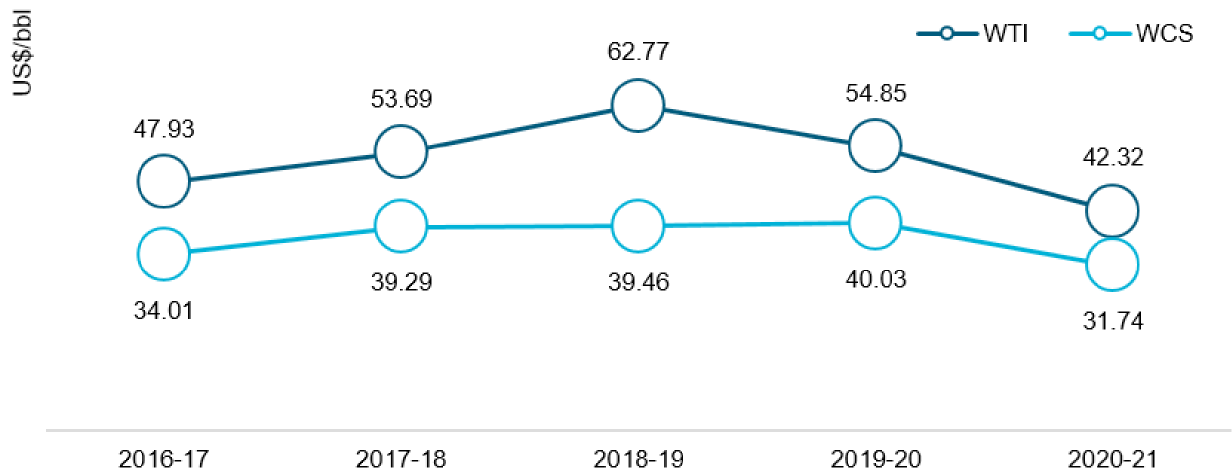
West Texas Intermediate (WTI) is the North American price benchmark for light sweet oil. Western Canadian Select (WCS) is a North American price benchmark for heavy crude oil, commonly used to price Canadian heavy oil.

WTI 2020-21 trend: Budget 2020 was based on an estimate of US$58.00 per barrel price for WTI crude oil and an exchange rate of 76.5 cents U.S. to the Canadian dollar in 2020-21. The actual WTI price averaged US$42.32 per barrel in 2020-21 and the exchange rate averaged 75.75 cents U.S. to the Canadian dollar. WTI prices decreased in 2020-21 compared to the previous fiscal year as the COVID-19 outbreak affected the global crude oil demand and reduced oil prices. The exchange rate, while lower than budgeted, increased the value of crude oil in Canadian dollars, resulting in higher revenue. This partially offset the effect of the lower WTI actual price. In addition, Saudi Arabia and Russia became engaged in a price war in late March

[i] 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.

2020 before reaching an agreement with other Organization of the Petroleum Exporting Countries (OPEC) and some non-OPEC crude oil producers on April 12, 2020. The price war led to a substantial decrease in WTI prices. The production cut agreement is scheduled to be in place until April 2022.

Crude Oil Prices

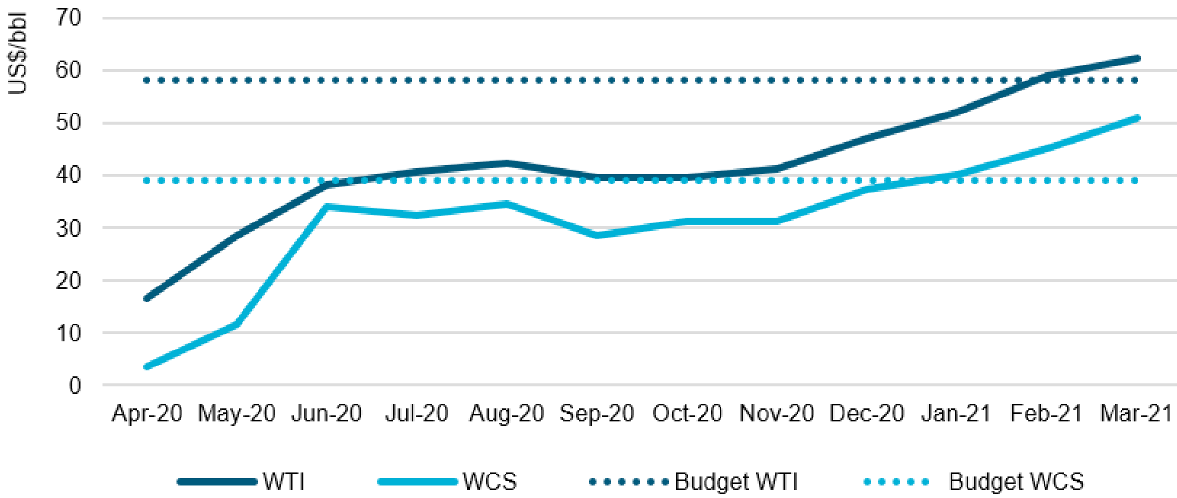


Source: Government of Alberta

WTI five-year trend: WTI prices increased from US$47.93 per barrel in 2016-17 to a high of US$62.77 per barrel in 2018-19 as the OPEC members and some non-OPEC producers agreed to reduce output by 1.8 million barrels per day. The WTI price decreased in 2019-20 as global economic weakening outweighed heightened geopolitical risks and the COVID-19 outbreak in the fourth quarter of 2019-20, down to a low of $42.32 in 2020-21.

WCS 2020-21 trend: The WCS price was estimated at US$38.90 per barrel for 2020-21 in Budget 2020. WCS price decreased significantly to US$31.74 per barrel in 2020-21, and was lower than the price that was anticipated in Budget 2020. WCS started the 2020-21 fiscal year at US$3.50 per barrel as the COVID-19 pandemic led to a decrease in global crude oil demand and impacted crude oil prices. As demand improved through the year and the OPEC and some non-OPEC producers reached an agreement to balance global supply and demand, WCS increased through the fiscal year, reaching US$50.94 by March 2021.

2020-21 Crude Oil Prices



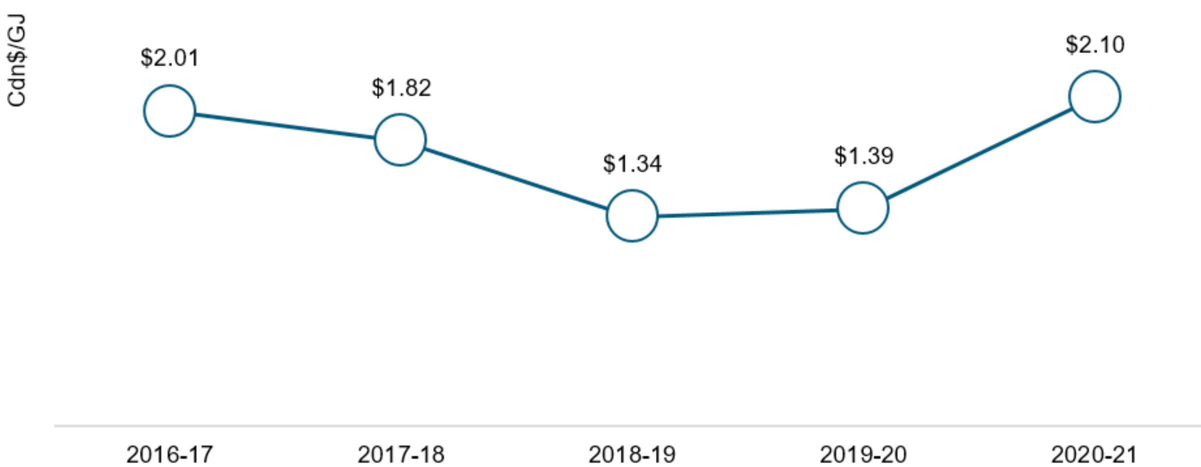
Source: U.S. Energy Information Administration; Ministry of Energy

WCS five-year trend: The WCS price has experienced some recovery since 2016-17. The supply growth in Western Canada constrained takeaway capacity, and the deep U.S. Midwest refinery turnaround season in 2018 resulted in wider light-heavy differentials in late 2018. The decline in international crude oil prices close to the end of 2018 also pushed the WCS prices to historical lows. Fiscal year prices for the five years, reported in the chart above, show that WCS prices started to recover in early 2019 with improving global oil prices and the Government of Alberta's curtailment policy. The WCS price received an additional uplift from the Alberta crude oil curtailment and continued reduction in Venezuelan heavy oil supply due to the U.S. sanctions, bringing the WCS price to an average US$40.03 per barrel in 2019-20 before the impacts of 2020-21.

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

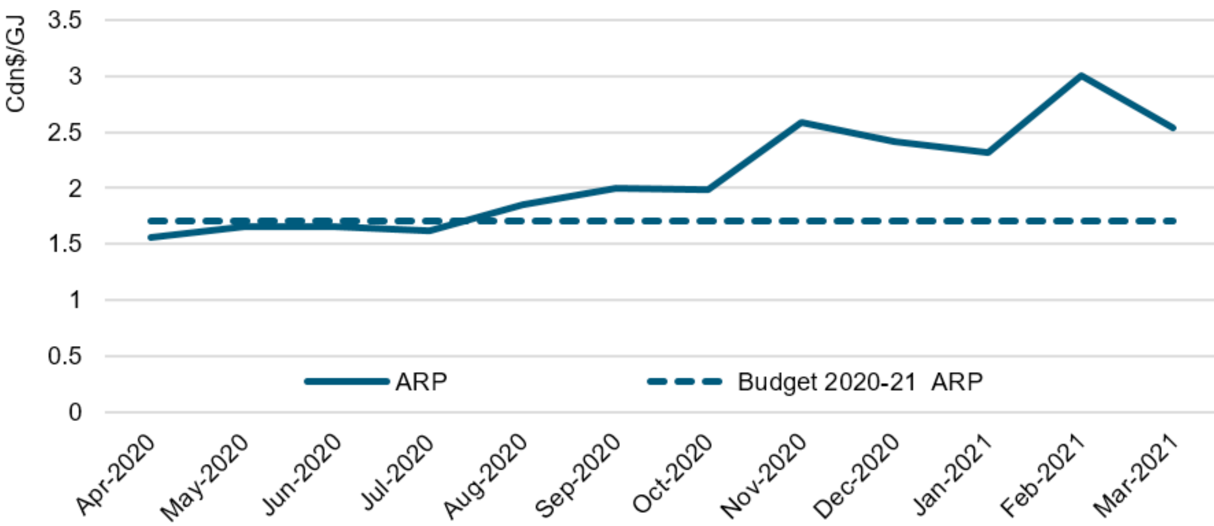
Overall, the general rule of supply and demand balance determines natural gas prices in North America. Storage levels and weather patterns affect prices as these factors impact the market's ability to respond to additional demand. Lower storage levels could lead to higher prices and vice-versa. Lower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

Royalties in Budget 2020 were based on a gas price forecast of ARP at $1.70/gigajoule (GJ). The realized ARP averaged $2.10/GJ in the fiscal year 2020-21. The actual gas price was above budgeted levels at the end of the fiscal year due to a combination of Canadian production decline, extreme cold weather conditions in February and strong heating and storage injection demand.

Furthermore, Nova Gas Transmission Ltd. (NGTL) pipeline system's Temporary Service Protocol (TSP), designed for the summers of 2019 and 2020, provided a mechanism for shippers to access storage on the NGTL system during planned summer maintenance periods in Western Canada. The implementation of TSP helped reduce price volatility.

Between 2017 and 2019, Alberta's natural gas prices were generally depressed, primarily due to infrastructure issues combined with restriction protocol during summer maintenance periods when natural gas demand was low on TC Energy Corporation's NGTL pipeline system. As such, low natural gas prices and large price fluctuations were observed, causing a downward trend for Alberta gas reference price, which decreased from $2.01/GJ in 2016-17 to $1.39/GJ in 2019-20.

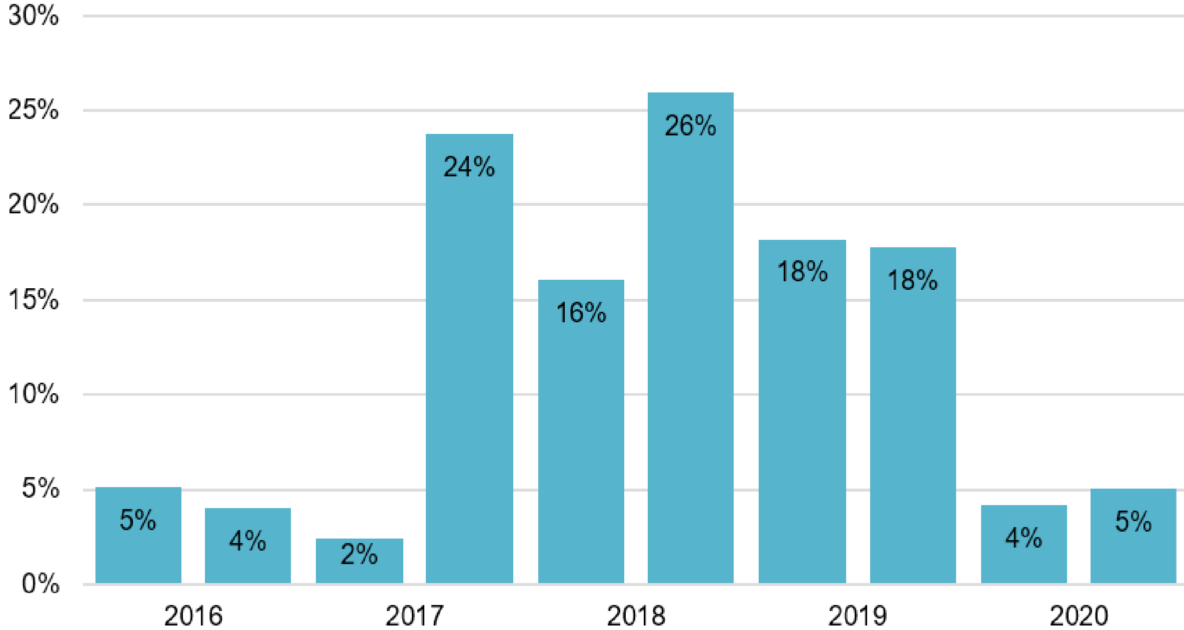
2020-21 Alberta Gas Reference Prices



Source: Government of Alberta

Alberta's natural gas prices increased to $2.10/GJ in 2020-21 fiscal year in part due to the implementation of the TSP, pipeline expansions on the NGTL system and strong domestic demand.

Average Daily AECO Price Change



Source: Government of Alberta

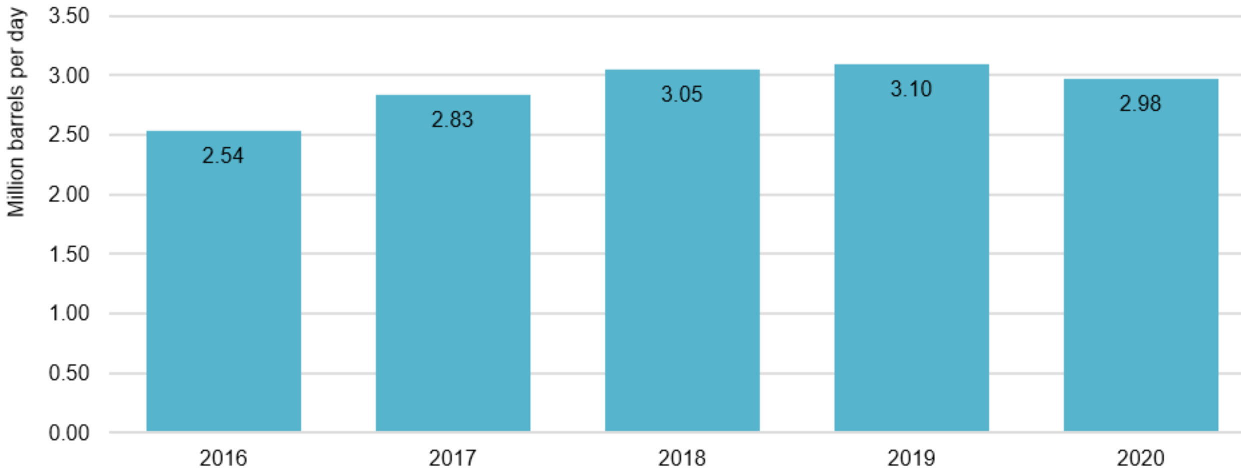
Measuring the AECO price volatility helps to identify if further regulatory intervention is required. While some volatility in a market reflects a functional market balancing supply and demand dynamics, excessive volatility can result from insufficient market regulation. Assessing with a semi-annual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

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

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

Production: Performance Indicator 1.b[i]

Alberta Crude Bitumen Production



Source: Alberta Energy Regulator

Crude bitumen production, which consists of mined and in-situ production, decreased by about four per cent from 3.10 million barrels per day in 2019 to 2.98 million barrels per day in 2020. In 2020, the decline in crude bitumen production in Alberta was due to the impacts of COVID-19 pandemic, which significantly affected crude oil demand in Alberta's traditional market, the United States.

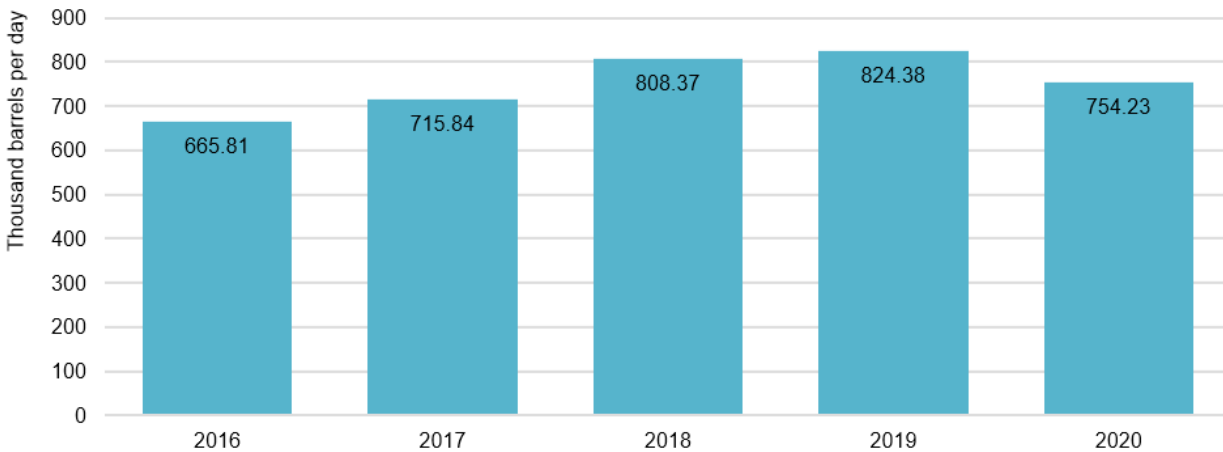
During 2020, both total mined production and in situ production declined by about four per cent from the 2019 level. From 2019 to 2020, mined bitumen production declined from 1.55 million barrels per day to 1.48 million barrels per day, and in-situ production declined from 1.55 million barrels per day to 1.49 million barrels per day.

The share of crude bitumen production as a percentage of global consumption was at about 3.3 per cent in 2020. Alberta accounts for 100 per cent of Canadian crude bitumen production.

Production of crude oil and equivalent (condensate and pentanes plus) declined by about 8.5 per cent, from about 824,400 barrels per day in 2019 to about 754,200 barrels per day in 2020. Conventional production decreased by about 13 per cent from 2019 to 2020, from about 487,300 barrels per day to 422,900 barrels per day. Condensate and pentanes plus production experienced year-over-year increases from 2012 to 2019. However, in 2020, the total production of condensate and pentanes plus declined by about two per cent from 337,000 barrels per day in 2019 to about 331,300 barrels per day in 2020.

[i] Note: Further information on sources and methodology for this performance indicator can be found in the Performance Measure and Indicator Methodology section on page 87.

Alberta Conventional Crude and Equivalent Production

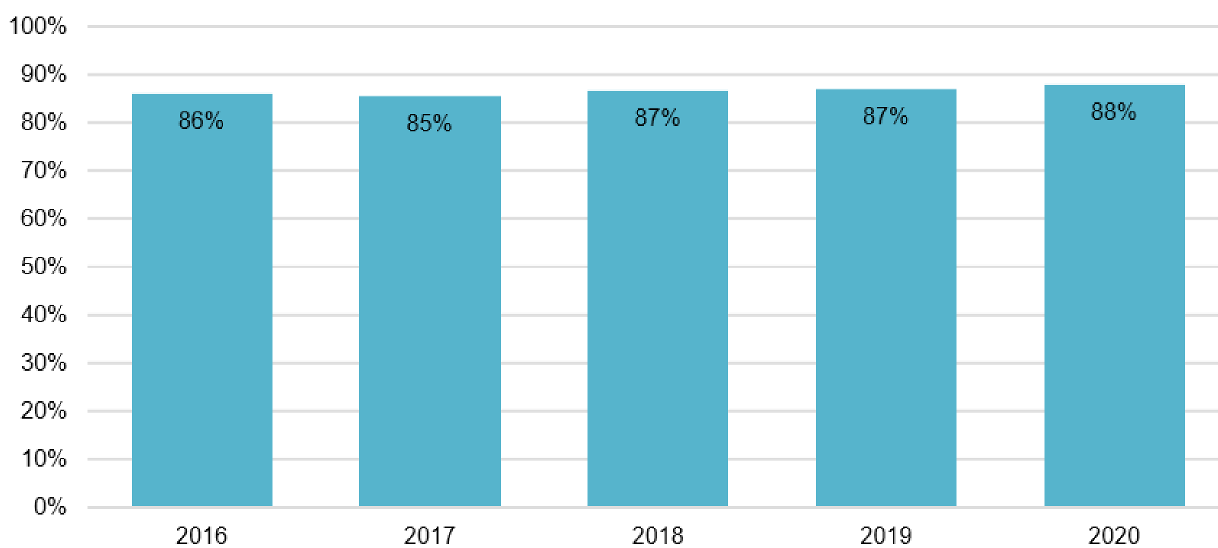


Source: Alberta Energy Regulator

The reduction in conventional oil production, and condensate and pentanes plus in Alberta took place for the same reason as the reduction in crude bitumen production – the impact of COVID-19 on demand for Alberta's crude oil in the United States.

Alberta accounts for a significant majority of Canada's crude oil and equivalent production. According to the Canada Energy Regulator, in 2020, total Alberta crude oil and equivalent production, which consists of conventional crude production, non-upgraded and upgraded bitumen, and condensate and pentanes plus was estimated to account for 80.4 per cent of total Canadian production. This was virtually unchanged from the 2019 share of 80.5 per cent of Canadian production. Over the 2016-2020 period, Alberta's share of Canadian production was generally consistent at around 80 per cent, ranging from 79.8 per cent in 2016 to 81.1 per cent in 2018.

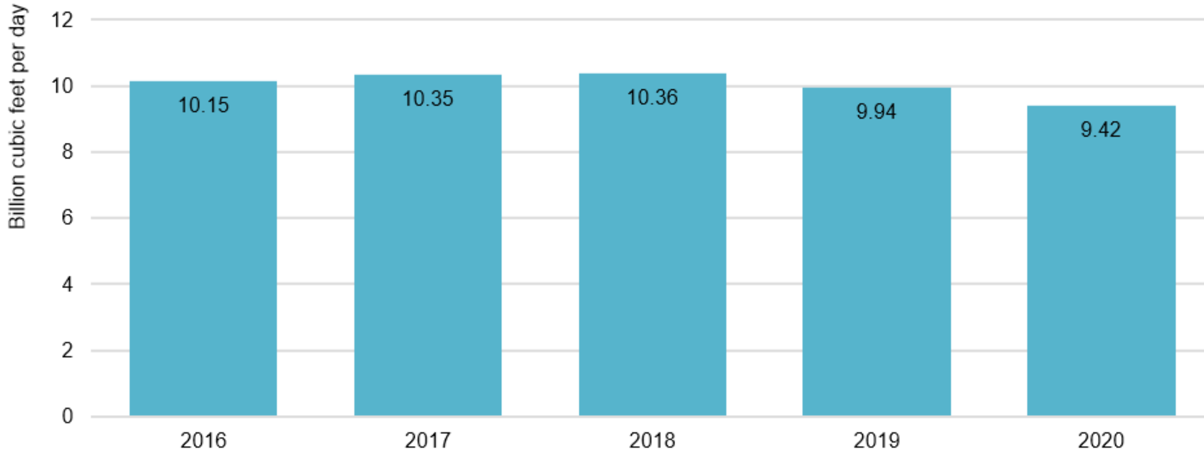
Total Percentage of Crude Oil and Equivalent Production Leaving Alberta



Source: Alberta Energy Regulator

The significant majority of Alberta oil disposition goes to the United States and other Canadian jurisdictions. In 2020, about 88 per cent of Alberta's total crude oil and equivalent disposition left the province. This was an increase of about one per cent from 87 per cent recorded in 2019.

Natural Gas Production

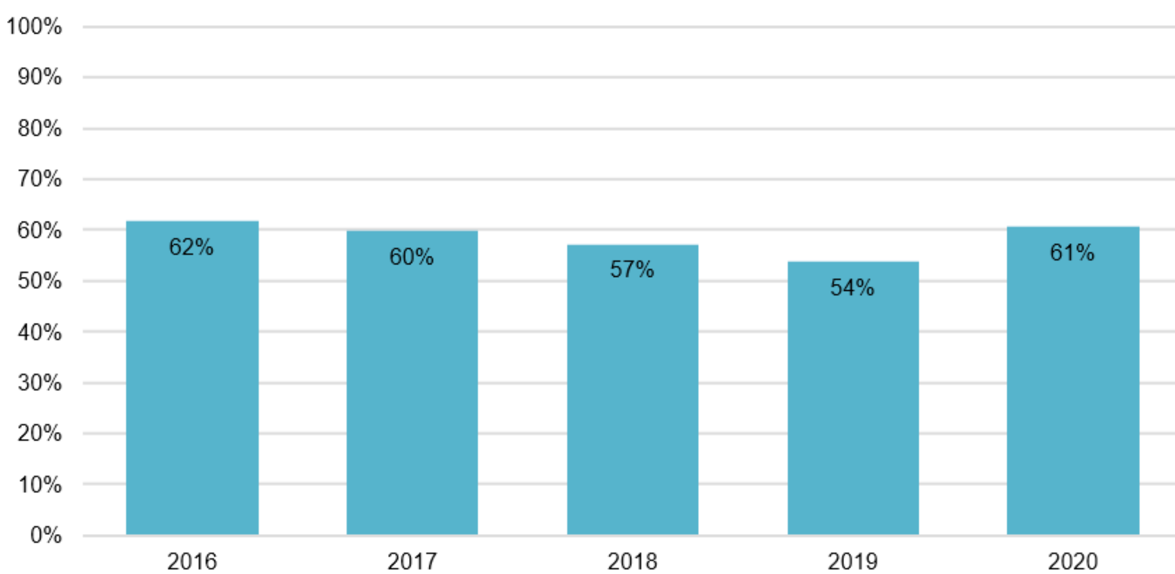


Source: Alberta Energy Regulator

From 2019 to 2020, marketable natural gas production declined approximately five per cent, with a 0.52 billion cubic feet per day reduction from 9.94 billion cubic feet per day in 2019 to 9.42 billion cubic feet per day in 2020. The production decline was mainly due to the impact of COVID-19 on the energy sector. The decline was also related to the decline in associated gas from oil wells as a result of the significant oil price decline that took place in 2020. Overall, total natural gas liquids production decreased by five per cent in 2020 from its 2019 level. Condensate is used as diluent that is blended with non-upgraded bitumen and heavy crude oil to meet pipeline specifications for transportation. While condensate demand experienced some decline, it was still sufficient to support gas production. By the end of 2020, the condensate demand had recovered to close to the pre-pandemic level, as the oil sands production had started to recover.

Alberta accounts for a majority of Canada's marketable natural gas production. In 2020, according to the Canada Energy Regulator, Alberta accounted for an estimated 62.9 per cent of total Canadian production. This represented a decline from 64.7 per cent in 2019. Over the 2016-2020 period, Alberta accounted for approximately two-thirds of Canadian production, ranging from 62.9 per cent in 2020 to 67.9 per cent in 2017.

Total Percentage of Gas Leaving Alberta

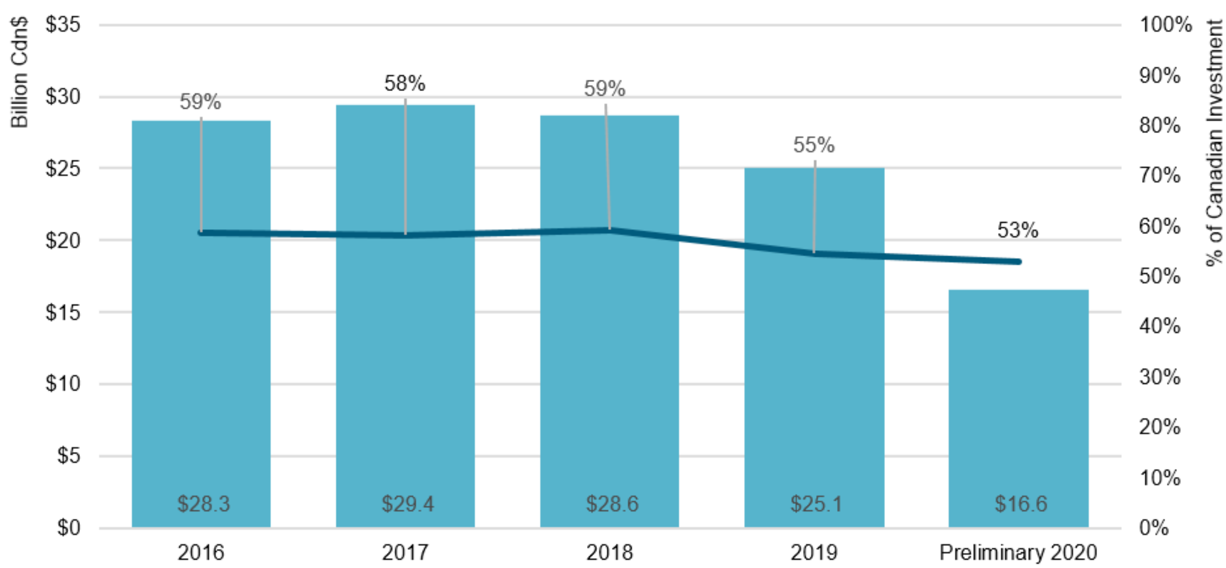


Source: Alberta Energy Regulator

In 2020, a majority of Alberta's total gas disposition, about 61 per cent, was exported to the rest of Canada (26 per cent) and the United States (34 per cent). In 2020, the declining trend for the share of gas disposition leaving the province was reversed, as the share of disposition increased from 54 per cent in 2019 to 61 per cent in 2020. The increase in the share of natural gas leaving Alberta was due to higher exports to other Canadian provinces and the U.S., primarily due to improved pipeline takeaway conditions and the declines of associated gas production in the U.S.

Investment: Performance Indicator 1.c[i]

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



Source: Statistics Canada

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

Total upstream energy industry investment in Alberta for 2019 was $25.1 billion, accounting for 55 per cent of Canadian upstream investment; these results supersede the preliminary actual results that were reported in the 2019-20 Annual Report.

For the year 2020, preliminary actual results have been released. The COVID-19 pandemic had a major negative impact on investment in the industry and led to significant declines in investment. As the demand for oil declined and as oil production experienced significant temporary reductions, investment in the sector also experienced a major decline. If the 2020 preliminary actual result of $16.6 billion materializes, investment in Alberta's mining, quarrying, and oil and gas extraction sector would be at the lowest level for the entire 2006-2020 period, with 2006 being the first year of the capital expenditure data series was reported by Statistics Canada.

Although the investment in the mining, quarrying, and oil and gas extraction industry in Alberta has been estimated to decline in 2020, Alberta still attracted more investment in this industry than all of the rest of Canada combined, demonstrating the importance of Alberta's energy industry investment to all Canadians

[i] Further information on sources and methodology for this performance indicator can be found in the Performance Measure and Indicator Methodology section on page 87.

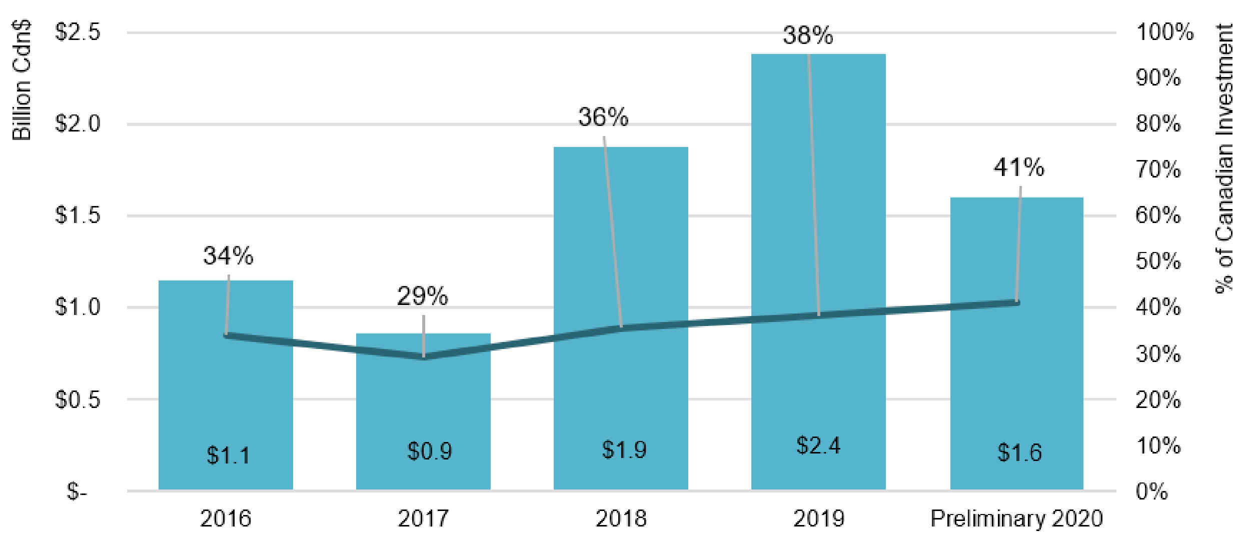
Upstream versus Downstream – What is the difference?

The terms upstream and downstream refer to activities at different points of the energy sector supply chain. Upstream operations include exploration and extraction of naturally occurring minerals such as crude petroleum, natural gas and coal. The production of conventional oil and gas, and the mining and extraction of oil from oil sands are included in the upstream sector. Alberta plays a major role in Canada's upstream energy industry.

Downstream activity includes the transformation of crude petroleum, natural gas and coal into intermediate and end products, through processes such as petroleum refining. Downstream activity also includes petrochemical manufacturing. Downstream activity creates additional economic impacts for Alberta; however, it is significantly more difficult to demonstrate these impacts compared to the upstream energy industry, as downstream impacts are dispersed throughout different industries. Due to these limitations, downstream activity in the Annual Report is focused on petroleum and coal product, and chemical manufacturing.

In 2020, investment in Alberta's upstream energy industry was estimated to account for 53 per cent of the total Canadian investment in this industry. The COVID-19 pandemic had a negative impact on the energy industries in other Canadian energy producing provinces as well, with the estimated mining, quarrying, and oil and gas investment in British Columbia and Saskatchewan also experiencing significant declines from 2019 to 2020.

Capital Investment in Alberta Downstream Sector

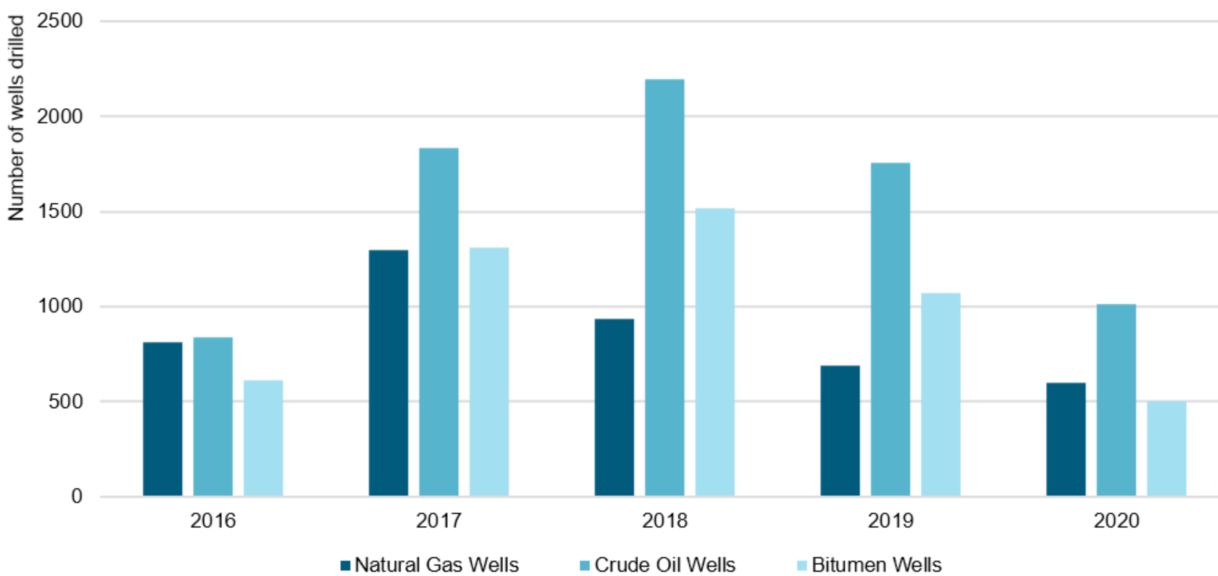


Source: Statistics Canada

It is significantly more difficult to examine the downstream energy industry than the upstream, as the products derived from oil, gas, oil sands and other minerals are common in daily life, and are depended upon in virtually all industrial and consumer sectors. Given this downstream impacts cannot be easily captured. Due to these limitations, downstream investment is focused on petroleum and coal product manufacturing, and chemical manufacturing. This allows for the coverage of petroleum refining and petrochemical manufacturing activity, among other downstream activities.

Overall, the trends that were observed, in Alberta, for the upstream energy industry investment over the 2016-2020 period did not consistently translate into similar trends for the downstream investment. The smaller downstream capital investment is much more susceptible to significant year-over-year swings due to major one-time investment decisions that may not actually reflect industry trends. From 2018 to 2019, while investment in the mining, quarrying, and oil and gas extraction sector declined, investment in the downstream actually went up, from about $1.9 billion to about $2.4 billion. Preliminary overall Alberta downstream investment in 2020 was estimated to decline to by about 33 per cent to about $1.6 billion from its 2019 level, although the decline was primarily driven by the chemical manufacturing sub-sector. Estimated investment in petroleum and coal products manufacturing sub-sector experienced a much smaller year-over-year decline. It is difficult to determine the trend for Alberta downstream investment, which consists of a range of industries with varying manufacturing end products. The Government introduced the Alberta Petrochemicals Incentive Program (APIP) in 2020 to encourage new investment in the sector.

Drilling

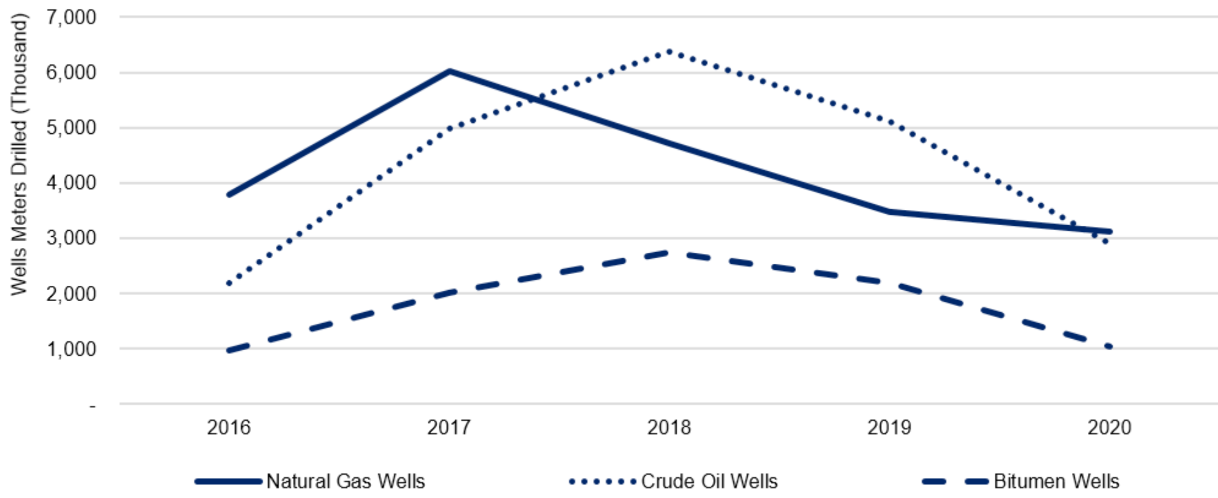


Source: Alberta Energy Regulator

The above chart presents drilling activity in Alberta over the 2016-2020 period. Wells drilled include both development and exploratory wells. After the significant decline in the total number of wells drilled in Alberta in 2016, drilling activity increased in 2017. In 2018, the number of crude oil and bitumen wells continued to increase relative to the 2017 level, while the number of natural gas wells declined. In 2019 and 2020, drilling activity declined for all three types of wells – crude oil, bitumen and natural gas wells.

The total successful natural gas wells drilled decreased by 13 per cent, from 687 in 2019 to 598 in 2020, as low prices, capital restraint by producers, pipeline capacity constraints, the impacts of COVID-19 and the impacts of weather contributed to decreased activity across the province. Similarly, the total successful crude oil wells drilled decreased by 42 per cent, from 1,755 in 2019 to 1,014 in 2020 due to market access, the impacts of COVID-19, along with conservative capital programs. Bitumen wells drilled also followed the downward trend, decreasing by 53 per cent from 1,069 in 2019 to 503 in 2020.

Wells Metres Drilled



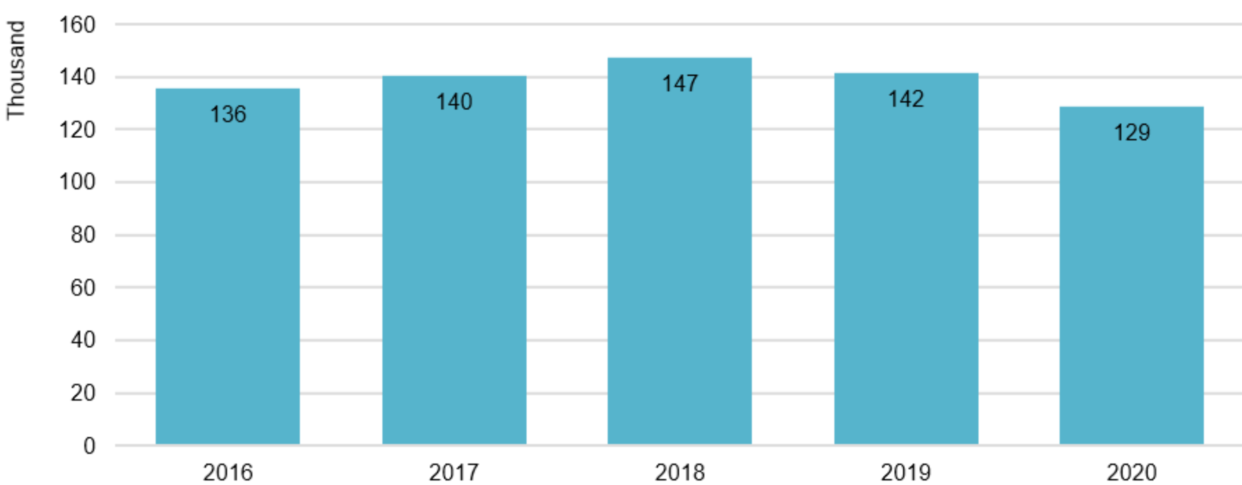
Source: Alberta Energy Regulator

Between 2016 and 2020, the lowest total number of meters drilled in crude oil and bitumen wells occurred in 2016, while for natural gas it was in 2020.

Land Sales

As a result of the challenges Alberta's energy sector faced in early 2020, due to the pandemic, the ministry deferred all public offerings (i.e., land sales) and direct purchases of petroleum and natural gas and oil sands mineral rights in April 2020. Once the business environment had sufficiently improved, land sales were resumed and in an effort to make new lands available as quickly as possible, an accelerated sales resumption plan was implemented in October 2020.

Employment



Source: Statistics Canada[i]

Employment in the mining, quarrying, and oil and gas extraction sector has been important to Alberta's economic performance. From 2016 to 2018, employment in the sector started to recover, and increased from 136,000 people to 147,000 people. In 2019, employment in the sector declined by about four per cent relative to its 2018 level to about 142,000 people. The COVID-19 pandemic had a significant negative impact on the sector. In 2020, employment in the sector declined by nine per cent compared to 2019, to 129,000 jobs.

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

Royalty Programs

The Government of Alberta owns 81 per cent of oil and gas and other mineral resources in Alberta and collects royalties from companies when an oil or gas well, oil sands project, or mineral project is in production. On behalf of Albertans, the ministry reviews and maintains a competitive and effective royalty regime that attracts industry investment, which provides jobs, business opportunities, tax and royalty revenue and numerous other benefits to the provincial economy. This work supports outcome one from the Ministry of Energy's 2020-24 Business Plan: Albertans benefit economically from investment in responsible energy and mineral development and access to global markets.

Royalty programs exist for a number of reasons, such as:

- 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.

Two royalty frameworks currently run programs in Alberta, the Modernized Royalty Framework and the Alberta Royalty Framework.

As the Modernized Royalty Framework took effect on January 1, 2017 and includes two new 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 of 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 of each royalty program reflects the revenue from wells that are qualified for the respective royalty programs in a given year. It does not represent the net revenue from those wells as the royalty revenue on natural gas and gas products can be further reduced by eligible deductions, such as the Gas Cost Allowance.
- The royalty programs under the Alberta Royalty Framework are reported on a calendar year basis and reflect the amendments filed by industry each year.
- The royalty programs under the Modernized Royalty Framework are reported on a fiscal year basis to align with government reporting as a whole and reflect amendments filed by industry each year.
- In June 2019, government introduced the *Royalty Guarantee Act* to increase investor certainty that the royalty structure in place when a well is drilled will remain in place for at least 10 years.

Modernized Royalty Framework Royalty Programs

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

Enhanced Hydrocarbon Recovery Program

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

The objectives of the Enhanced Hydrocarbon Recovery Program are to:

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

During the 2019-20 fiscal year, the Enhanced Hydrocarbon Recovery Program received nine applications. Since the program's inception in 2017, 32 applications were received from 22 companies, of which 11 were approved.

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

- Four applications for the secondary recovery phase of oil and one application for the secondary recovery phase of gas, 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 2019-20 fiscal year.
- One application for the tertiary recovery phase of oil and one application for the tertiary recovery phase of gas, which includes enhancing the recovery of oil from an oil pool by miscible flooding, immiscible flooding, solvent flooding, chemical flooding or similar techniques, was approved during the 2019-20 fiscal year.

The active enhanced recovery schemes in the program generated a total Crown production of 103,874 cubic

EHRP Applications

	2017-18	2018-19	2019-20	Total
Number of Applications Received	11	12	9	32
Number of Different Companies Submitting Applications	8	11	7	22
Number of Applications Approved	0	4	7	11
Number of Applications Denied	0	11	4	15
Number of Applications Withdrawn	0	1	0	1
Applications to be Processed at the end of 2019-20 Fiscal Year				5

metres of oil, and 202,207,200 cubic metres of gas in 2019-20. In comparison, active enhanced recovery schemes generated a total Crown production of 53,936 cubic meters of oil, and 126,666,200 cubic meters of gas in 2018-19.

Total Crown royalty volumes from the approved enhanced recovery schemes totaled 5,195 cubic metres of oil, 2,347 cubic metres of natural gas liquids and 15,275,000 cubic metres of gas, which translates to about $3.1 million in total royalty revenue in 2019-20 and an increase of 71 per cent from 2018-19. Of this total royalty revenue, about $1.3 million was considered incremental royalty to the Crown that otherwise would not have been generated without the program.

	2017-18	2018-19	2019-20
Total Crown Royalty Volumes – Oil (m^3)	1,071	2,698	5,195
Total Crown Royalty Volumes – NGL (m^3)	164*	1,395*	2,347
Total Crown Royalty Volumes – Gas (10^3m^3)	5,773*	12,407*	15,275
Total Crown Royalty Revenue ($)	817,788*	1,820,232*	3,114,633
Incremental Crown Royalty Revenue - Oil ($)	233,380	575,173	1,327,051

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

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

Emerging Resources Program

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

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

	2016-17	2017-18	2018-19	2019-20	Total
Number of Applications Received	4	7	6	4	21
Number of Different Companies Submitting Applications	4	6	5	4	14
Number of Applications Approved	0	1	3	3	7
Number of Applications Denied	0	4	1	5	10
Number of Applications Withdrawn	0	0	1	0	1
Applications to be Processed at the end of 2019-20 Fiscal Year					3

During the 2019-20 fiscal year, the Emerging Resources Program received four applications. Since the program was launched, 21 applications have been received from 14 companies. Seven applications were approved, 10 applications were denied, one was withdrawn, and three were under review at the end of the 2019-20 fiscal year.

The cumulative number of new project wells participating in the program in 2019-20 fiscal year was 4,080. The number of new project wells increased by 1,124 in 2019-20.

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

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

Approved projects in the program generated a total Crown production of 144,900 cubic metres of oil, 24,830 cubic metres of condensate, and 857,102,900 cubic metres of gas in 2019-20.

Total Crown royalty volumes from Emerging Resource Program projects totaled 7,246 cubic metres of oil, 37,126 cubic metres of natural gas liquids, 1,242 cubic metres of condensate, and 34,119,500 cubic metres of gas. This translates to about $17.1 million in total royalty revenue in 2019-20 from approved Emerging Resource Program projects, a 129 per cent increase from 2018-19. This royalty revenue to the Crown may not have been generated without the program incentives.

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

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

Alberta Royalty Framework Royalty Programs

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

Natural Gas Deep Drilling Program

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

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

The total residue gas production from eligible wells decreased by 41 per cent and liquids production decreased by 44 per cent from 2018 to 2019. Residue gas is the gas mixture left after separation and processing of natural gas liquids that are ready for delivery to the pipeline. The decrease in residue gas and liquids production is due to the termination of the program enrollment.

	2015	2016	2017	2018	2019
Total gas production from eligible wells	Residue Gas: 35,335,955 Liquids: 9,182,083	Residue Gas: 38,752,706 Liquids: 12,138,887	Residue Gas: 33,746,930 Liquids: 13,274,152	Residue Gas: 22,850,190 Liquids: 8,084,252	Residue Gas: 13,482,771 Liquids: 4,523,810
Total Royalty from NGDDP gas wells	$280 million	$261 million	$307 million	$176 million	$86 million

Note: Units of measurement for gas is 10^3m^3 and liquids is m^3

The total royalty revenue for NGDDP has decreased by 51 per cent from the 2018 result. In 2019, gas wells in the program contributed about $176 million in total royalty revenues. Total royalty revenue has decreased by $90 million, which is slightly more than 51 per cent from 2018. The decline in royalty revenue is consistent with the decline in production under the program. This is likely due to well production decline, or wells reaching the NGDDP net cap or 60 calendar months cap.

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

The Emerging Resources and Technologies Initiative

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

Production under the program is measured for wells in each of the four situations. In shale gas wells, horizontal gas wells and horizontal oil wells, the production has decreased significantly. This is the result of expected production declines in existing wells. In 2018, no new wells qualified for the program and production began to decline in existing wells.

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

Overall production from horizontal oil and gas wells decreased in 2019 compared to 2018. Gas production under the horizontal gas new wells decreased to 0.08 billion cubic metres in 2019 from 0.6 billion cubic metres in 2018. Liquids production also saw a decrease to 0.04 million cubic metres in 2019 from 0.5 million cubic metres in 2018. This is due to termination of the program so that no new wells that spud from 2017 onwards are eligible for the program and production decline from the existing wells as they mature. In addition, the pool of the ER&T wells has been shrinking as some of the remaining wells in the pool reach their production or volume cap, which also leads to production decreases.

Horizontal oil wells showed decreases of 73.8 per cent and 94.7 per cent in 2019 oil production and solution gas production, respectively, from 2018 to 2019. Oil production decreased to 0.2 million cubic metres in 2019 from 0.8 million cubic metres in 2018. Solution gas production decreased to 0.001 billion cubic metres in 2019 from 0.03 billion cubic metres in 2018. These decreases are due to termination of the program and high decline rate of the existing well production. Solution gas is the gas that is separated from crude oil or crude bitumen after recovery from a well event.

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

The total royalty revenue for ER&T in 2019 was approximately $18.7 million compared to the 2018 total royalty revenue of $62 million. Total revenue generated by wells in the program has decreased by 69.7 per cent compared to 2018. This accounts for 1.2 per cent of Alberta's total conventional Crown oil and gas revenues. Due to the fact that no new wells were accepted into the program since 2017, and with prolonged low commodity prices, the total contribution of these wells to royalty revenue will likely be limited too.

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

Incremental Ethane Extraction Program

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

The program allows for a 60-month royalty credit eligibility period. In the 2019 calendar year, 13 of the 16 approved projects were in-service for the program. These 13 in-service projects are capable of providing up to 85,073 barrels per day of additional ethane or about 93 per cent of the total approved incremental ethane capacity approved by the minister for the IEEP. In the 2020-21 fiscal year, the department issued approximately $13 million in royalty credits to these projects for 2019 production.

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

The supply and demand for ethane has continued to strengthen over the past few years and Alberta's petrochemical supply and demand balance is considered stable. The department will continue to process royalty credits associated with in-service ethane extraction projects that are within their 60-month credit eligibility period. The IEEP is being phased out and is scheduled to end on December 31, 2021.

Enhanced Oil Recovery Program

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

No new applications were received in 2019 under this program, and no new schemes were approved into the program since the program is being phased out.

EORP

	2016	2017	2018	2019
Total Crown production from EOR	705,035 m^3	717,828 m^3	642,834 m^3	502,289 m^3
Total Crown royalty volumes from EOR	125,567 m^3	103,927 m^3	103,891 m^3	69,605 m^3
Total Crown royalty revenue from EOR	$23.6 million	$37.2 million	$44.6 million	$27.1 million
Incremental Crown royalty revenue from EOR	$21.7 million	$34.6 million	$41.6 million	$27.0 million

Total Crown production from enhanced oil recovery in 2019 was 0.5 million cubic metres, which is a decrease of 140,545 cubic metres from the previous year. The Crown royalty volumes from active EOR schemes totaled to 69,605 cubic metres, which translates to approximately $27 million in total royalty revenue in 2019. The total royalty revenue decreased by over $17.5 million in 2019 from approximately $45 million reported in 2018. This is due to a significant drop in total Crown production from EOR (and in turn, total Crown royalty volumes from EOR) in 2019 together with significantly lower West Texas Intermediate (WTI) price in 2019 of around US$57/bbl compared to US$65/bbl in 2018. Higher WTI price tends to lead to higher royalty rate. Of this total royalty revenue, approximately $27 million was considered incremental royalty to the Crown that otherwise would not have been generated without the program. This is a $14.6 million decrease from approximately $41.6 million in incremental royalty revenue reported in 2018.

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

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

Priority One: Getting Alberta back to work

Objective 3: Reducing red tape

- The Ministry of Energy regularly engaged with industry stakeholders through working groups and industry panels to better understand and address concerns and recommendations to reduce red tape. In 2020-21, the ministry achieved a 15 percent reduction, surpassing government's interim target of 12 per cent. The ministry's red tape reduction initiatives have resulted in substantial cost savings for industry. For example, the Alberta Energy Regulator's updated directive for Water Disposal Limits and Reporting Requirements for Thermal In Situ Oil Sands Schemes could yield collective costs savings of up to $273 million for existing projects as per a CAPP estimate. The Ministry of Energy continues to solicit project ideas and prioritize initiatives to achieve red tape reduction goals and to address industry and public

Objective 5: Revitalizing and sustaining key industries

- In 2020-21, the management of the Orphan Wells throughout Alberta was improved through Bill 12, the *Liabilities Management Statutes Amendment Act*, as one part of Alberta's new liability management framework. The actions being taken under this new framework will shrink the inventory of inactive and orphaned wells across the province, ensure more timely restoration of land to its original state, and protect future generations from experiencing a backlog of sites needing clean-up and from paying these costs. On March 2, 2020, an additional interest-free $100 million loan to the Orphan Well Association was announced which has generated an average of 269 full-time direct jobs as of March 2021. As of March 31, 2021, the Orphan Well Loan Program has spent approximately $284 million of the total $335 million and reported the following results from its effort to address the growing inventory of orphaned sites: 3,235 wells abandoned; 3,667 pipelines decommissioned; and 1,608 sites reclaimed.
- The area-based closure program encourages companies to work together in project areas to close oil and gas infrastructure and sites. For the 2020 calendar year, 61 companies committed to spend nearly $332 million, with an additional 10 companies participating in the collaborative-only components of area based closure.
- The Site Rehabilitation Program launched on May 1, 2020, accessing up to $1 billion from the Government of Canada's COVID-19 Economic Recovery Plan. The program is already leading to indirect employment and economic benefits across the province, and is expected to generate almost 5,300 direct jobs. The program continues to make progress towards providing relief funding to eligible oil field service workers to perform well, pipeline, and oil and gas site closure and reclamation work. In total, as of March 31, 2021, over $343.4 million in grant funding has been approved and is being allocated to almost 500 Alberta-based companies, creating nearly 1,600 jobs so far.
- In January 2019, the Government of Alberta implemented a policy that limited crude oil production to match takeaway capacity from the province. This was done to protect the value of the province's oil by helping prevent Canadian crude from selling at large discounts. In October 2020, the curtailment policy was extended by an additional year until December 31, 2021, but it will only be used if a specific need arises. Since December 2020, monthly oil production limits have not been in effect. It is expected that sufficient export capacity will allow the system to operate efficiently on its own throughout 2021.
- The Alberta Petrochemical Incentive Program was launched in 2020 to help grow Alberta's petrochemical sector, which is expected to grow by more than $30 billion by 2030, and result in more than 90,000 direct and indirect jobs over the construction and operation periods of new facilities.

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

Priority One: Getting Alberta back to work

Objective 5: Revitalizing and sustaining key industries

- The ministry has undertaken wide-ranging efforts to further diversify the province's energy mix, including initiatives related to natural gas, liquified natural gas, and hydrogen. Carbon capture, utilization and storage, the plastics circular economy, minerals and metals are other areas being explored.
  - The Ministry of Energy released a forward-looking Natural Gas Vision and Strategy in October 2020 that is a key part of Alberta's Recovery Plan.
  - The Ministry of Energy continues to explore options to advance LNG projects with government partners to utilize Alberta natural gas as feedstock.
  - In 2020, the Ministry of Energy launched a targeted engagement process to help inform the engagement and development of a hydrogen roadmap for Alberta. As well, the province contributed to the Government of Canada's hydrogen strategy, which was released in December 2020.

Priority Three: Standing up for Alberta

Objective 1: Getting pipelines built

- Construction continued in Alberta in 2021 on TMX. In British Columbia, pre-construction work also continued in the Interior, North Thompson, and Fraser Valley regions, with pipe in the ground in the North Thompson area. At the peak of construction TMX construction, there will be 5,500 job opportunities, including 1,800 in Alberta and 2,200 in British Columbia. The Conference Board of Canada projects that, over a 20 year period, roughly $73 billion in increased revenues would be generated. Combined government revenue would be $46.7 billion with British Columbia receiving $5.7 billion; Alberta $19.4 billion and the rest of Canada, $21.6 billion.
- Enbridge Line 3 construction began on the final stretch of the Line 3 project in Minnesota on December 1, 2020, following final permitting approval in November. During peak construction, more than 5,500 workers were in Minnesota. The project is now more than 50 per cent complete. Legal challenges against Line 3 remain despite construction moving forward.
- Subsequent to the year end, on June 9, 2021, the APMC, as directed by the Alberta Government, and TC Energy have reached an agreement for an orderly exit from the KXL project and partnership. The two parties will continue to explore options to recoup the government's investment in the project. Final costs to the government are expected to be approximately $1.3 billion.
- Working with the Ministries of Justice and Solicitor General and Environment and Parks to defend Alberta's jurisdiction in the constitutional challenge of the Impact Assessment Act before the Alberta Court of Appeal.
- The Ministry of Energy worked with provinces, territories, and the federal government through formal forums and ongoing bilateral relationships to advocate for the timely completion of major oil pipeline projects and make our energy industry a top priority.

Objective 2: Standing up to foreign influences on Alberta's natural resources

- The Canadian Energy Centre's "When We Work, Canada Works" campaign, which was in market across Canada, highlighted pipelines, economic growth, jobs, and tax revenues as part of a longer term strategy supporting COVID-19 economic recovery.

Discussion and Analysis of Results

Outcome One

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

What it means:

The ministry develops and manages policies and programs related to the province's royalty system to attract industry investment, provide jobs, business opportunities, tax revenue, and numerous other benefits to the provincial economy. It advocates for increased pipeline access to global markets to strengthen both provincial and national economies, while proactively communicating how we produce 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 inter-provincial natural gas transportation and storage. The ministry advances a modern, market-based electricity system in Alberta that attracts investment and provides affordable electricity for consumers and job creators. Ministry activities to reduce burdensome red tape and improve investor certainty in the energy sector will further these outcomes and help get Albertans back to work.

Key objectives to support the achievement of this outcome include:

1.1 Improve market access for Alberta's energy resources and products through advocacy and other support for new, optimized and expanded pipelines.

1.2 Create an investment climate that supports the development of energy resources in the province, by:

- reducing red tape and cumbersome regulatory processes.
- advocating for natural gas and liquefied natural gas to expand market opportunities, and implementing initiatives that support natural gas value chains,
- defending Alberta's energy industry through the Canadian Energy Centre, and
- addressing the report from the public inquiry into foreign sources of funds behind the anti-Alberta energy campaigns.

Key Objective 1.1

Improve market access for Alberta's energy resources and products through advocacy and other support for new, optimized and expanded pipelines.

Market Access

Increasing market access and protecting the value of Alberta's energy exports is a top priority for government. All major pipeline projects have experienced, or are experiencing, delays due to regulatory and legal challenges at the state or federal levels. Without proper access to world markets, Canada – and Alberta – continues to lose billions of dollars.

Government of Alberta is advocating for all projects that secure additional market access for provincial oil producers and help protect the value of Alberta's resources, through activities such as:

- tracking key developments for projects that will increase market access for Alberta oil and gas producers;
- intervening at Canada Energy Regulator hearings that affect Alberta oil and gas interests;
- addressing federal legislation that impacts major infrastructure development and market access for Alberta crude, including the *Impact Assessment Act* and the *Oil Tanker Moratorium Act*; and
- asking Alberta's energy industry to increase advocacy efforts.

Market access activities in the department cost $443 million in 2020-21, predominately for the divestment of Crude by Rail program to industry. The department incurred $0.5 million for all other activities associated with the market access items identified in the following sections.

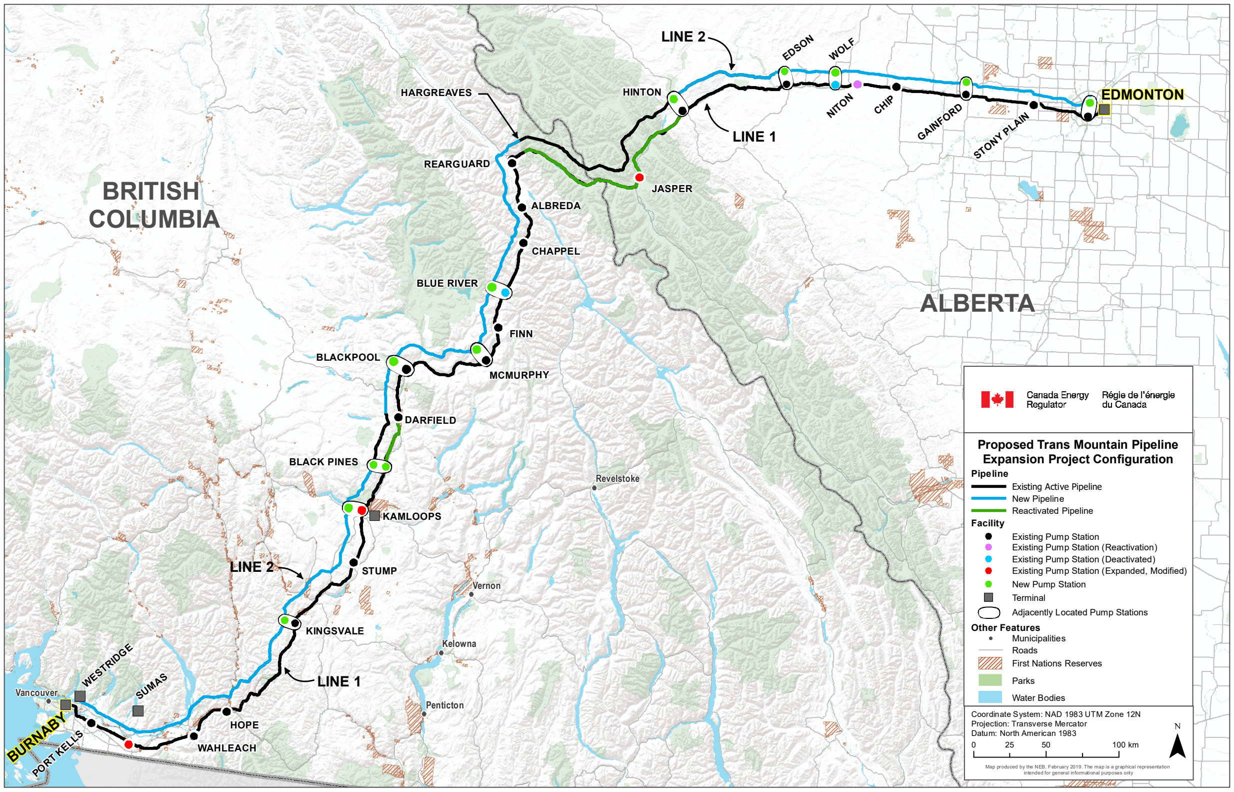
Trans Mountain Expansion Project

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

There is continued interest from First Nations in Alberta and British Columbia who are seeking to meaningfully participate in the project. In 2020, Alberta created the $1 billion Alberta Indigenous Opportunities Corporation (AIOC) to increase Indigenous communities' access to invest in natural resource projects. The AIOC bridges the gap between Indigenous groups seeking commercial partnerships in natural resource sectors and their financial capacity.

Construction continued in Alberta in 2021. In British Columbia, pre-construction work also continued in the Interior, North Thompson, and Fraser Valley regions, with pipe in the ground in the North Thompson area.

At the peak of construction, there will be 5,500 job opportunities, including 1,800 in Alberta and 2,200 in British Columbia. Contracted shippers have collectively committed to 80 per cent of the available capacity under long-term take-or-pay transportation contracts for 15 and 20 years. Those contracts are binding and take effect when the expansion pipeline comes into service. The Conference Board of Canada projects that, over a 20-year period, roughly $73 billion in increased revenues would be generated. Combined government revenue would be $46.7 billion, with British Columbia receiving $5.7 billion, Alberta receiving $19.4 billion and the rest of Canada receiving $21.6 billion.



Source: Canada Energy Regulator

There are no legal challenges against the project currently before the courts. As of February 2020, Trans Mountain Corp. announced that the project cost had increased from approximately $7.4 billion to $12.6 billion and estimates that the project will be operational by December 2022.

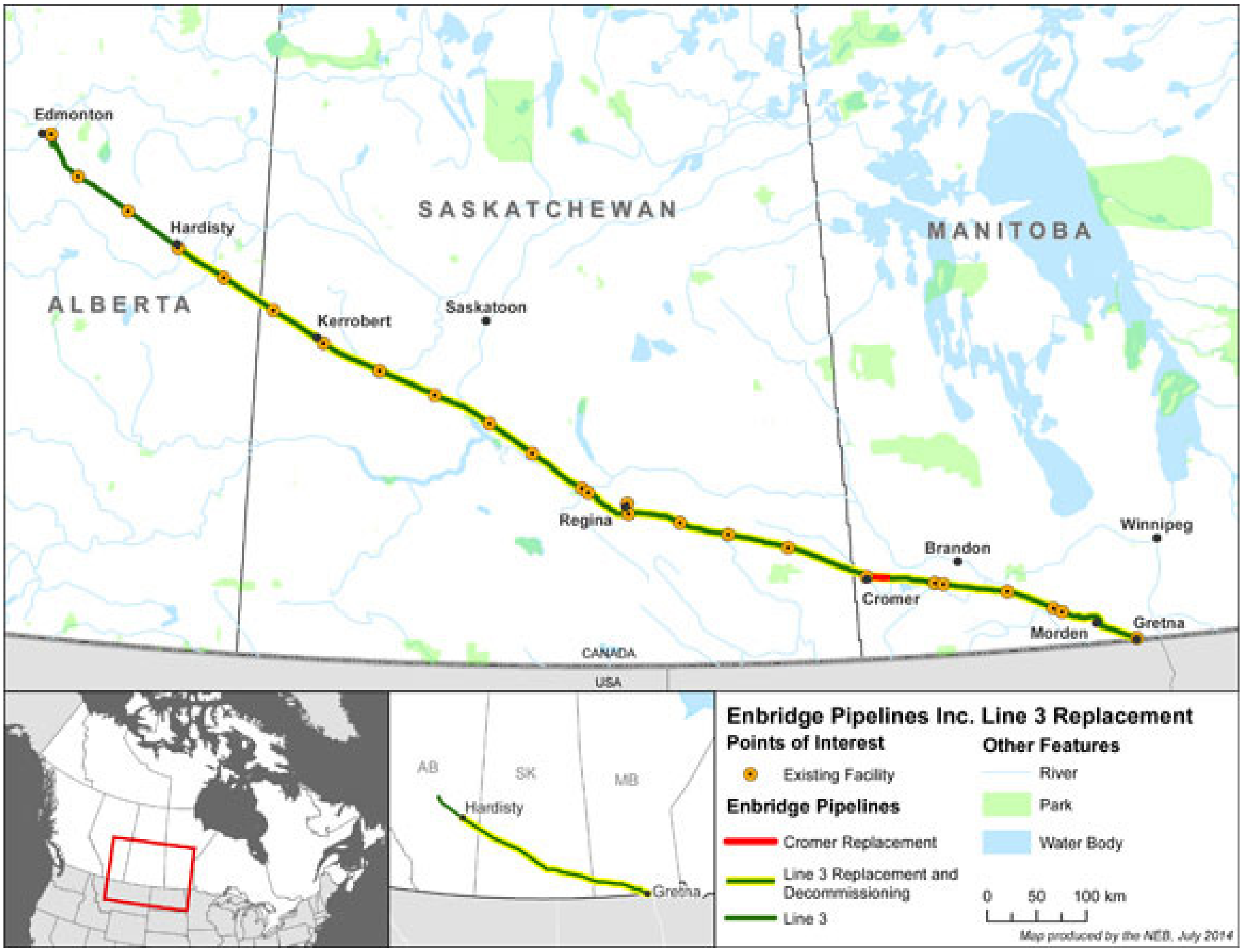
Since the arrival of COVID-19 in Canada last year, Trans Mountain has prioritized the health and safety of its workforce, families and the communities. Trans Mountain and its construction contractors continue to follow all advice from the federal and provincial governments and health officials. The company developed strict COVID-19 protocols and procedures in collaboration with provincial and municipal officials, as well as Indigenous groups, and publishes a monthly COVID-19 planning and response report on its website to keep the public apprised of its protocols and the current state of COVID-19 within Trans Mountain's overall workforce.

Enbridge Line 3

The Enbridge Line 3 Replacement Project is replacing 1,600 kilometers of 60-year old pipeline between Hardisty, Alberta and Superior, Wisconsin. This project will restore the old pipeline to its original capacity of 760,000 barrels per day and will provide reliable energy, jobs and economic benefits on both sides of the border.

Construction began on the final stretch of the Line 3 project in Minnesota on December 1, 2020, following final permitting approval in November. During peak construction, more than 5,500 workers were in Minnesota. The project is now more than 50 per cent complete. Legal challenges against Line 3 remain despite construction moving forward. Plans to complete the remaining 337 miles of the project were originally approved by the Minnesota Public Utilities Commission earlier in 2020; however, the segment is now facing its third appeal from the Minnesota Commerce Department, as well as several environmental and tribal groups.

The in-service date for Line 3 is currently scheduled for the fourth quarter of 2021.



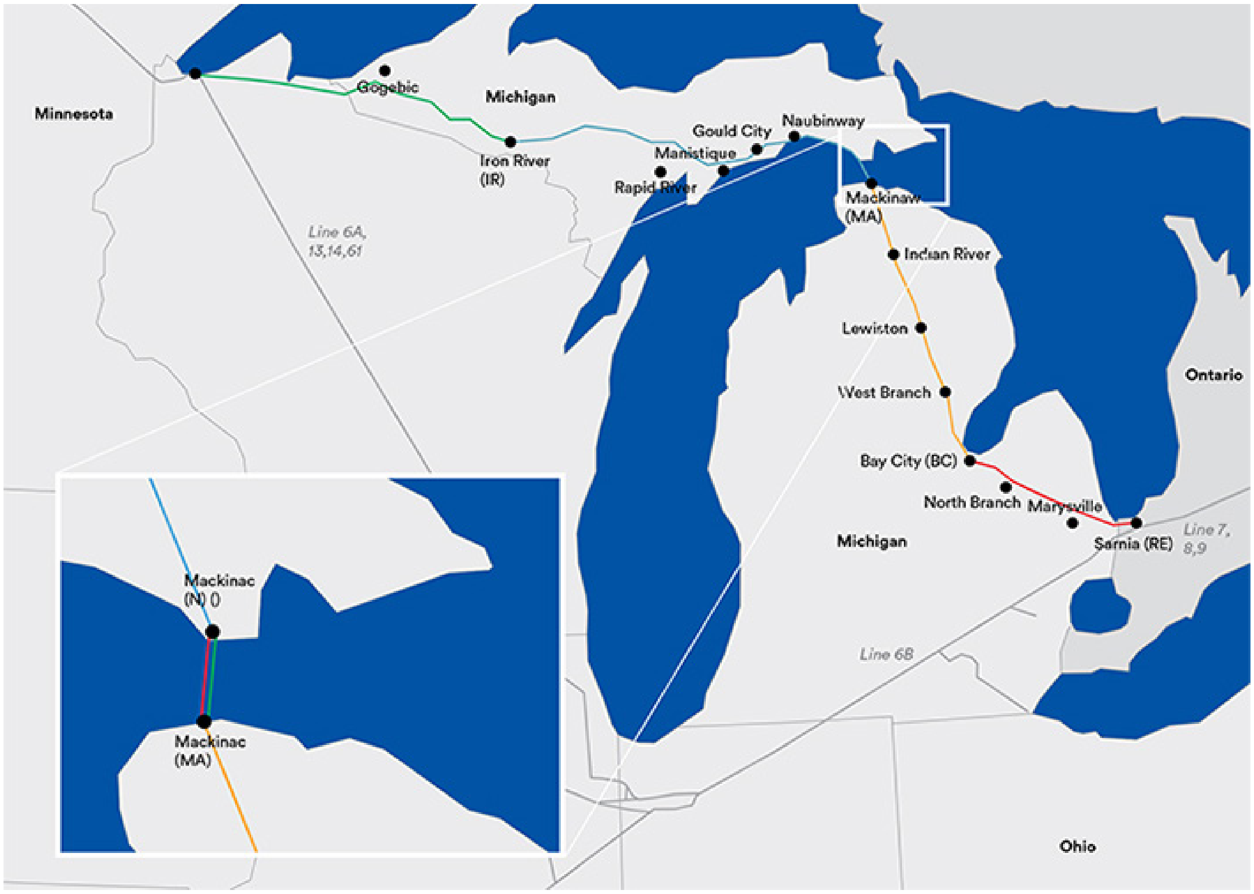
Source: Canada Energy Regulator

Enbridge Line 5

The Government of Alberta continued to advocate for Enbridge's Line 5 during 2020-21.

On November 13, 2020, Governor Gretchen Whitmer notified Enbridge that the 1953 easement, which allows the company to operate its dual pipelines in the Straits of Mackinac, is being revoked and terminated. The termination requires Enbridge to cease operations of the dual pipelines in the Straits no later than May 2021 to allow for an "orderly transition that protects Michigan's energy needs" according to Whitmer's office. In response to the state, Enbridge filed a federal complaint on November 24, 2020, in the United States District Court for the Western District of Michigan seeking an injunction to stop the State of Michigan from taking any steps to prevent the operation of Line 5. As of May 2021, this issue is being considered in federal court to determine whether the State of Michigan or the U.S. federal government has legal jurisdiction over the pipeline.

This pipeline is a critical source of propane and crude oil supply to Ontario, Quebec, Michigan and the Great Lakes Region. Shutting it down would lead to a serious disruption of the energy market. A shutdown would also create a bottleneck in the Midwest, negatively impact oil prices, limit the flow of up to 400,000 barrels per day of Alberta oil and impact Alberta propane producers, as Michigan would have to source a more expensive alternative source of propane supply from the U.S. Gulf Coast, or through trucking and rail from Canada.



Source: Enbridge

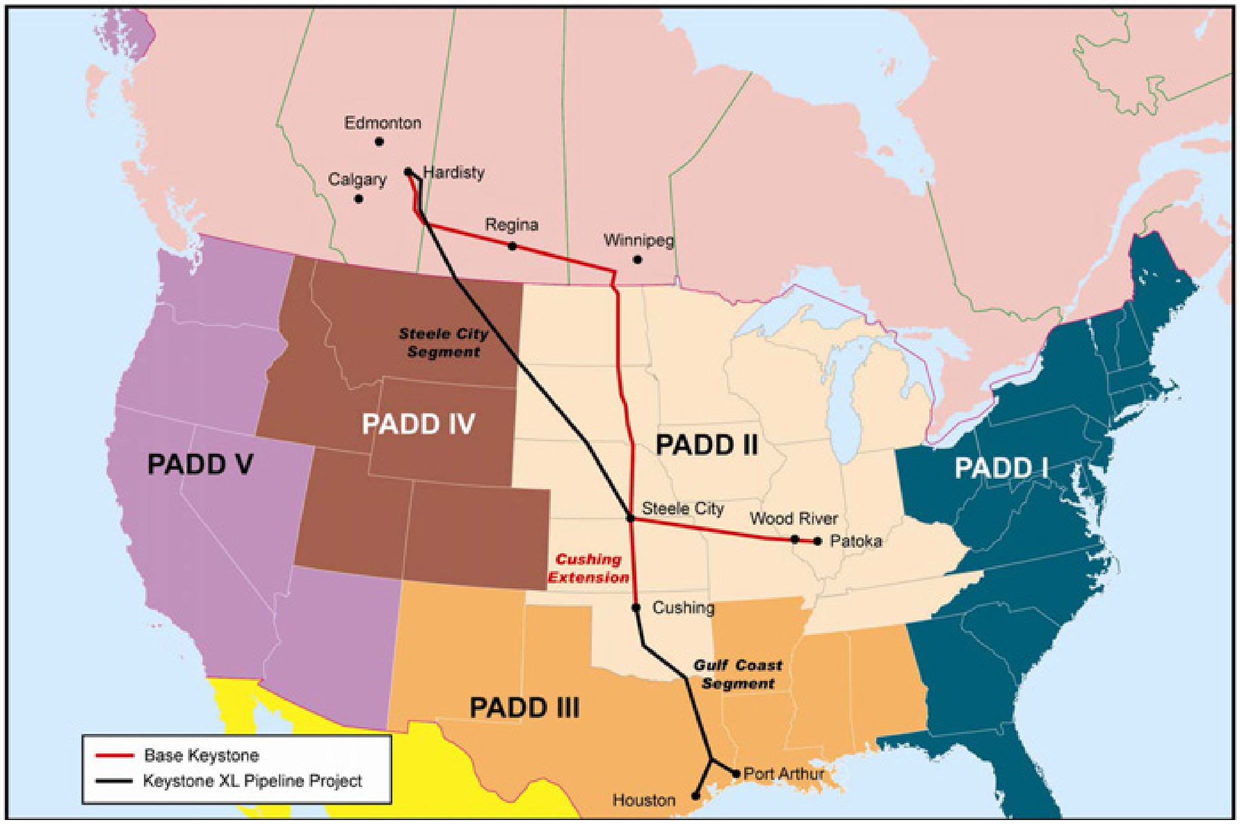
The Government of Alberta is supportive of the project as a vital and responsible energy corridor for the state, and continues to work with the Government of Canada, provincial counterparts, and Enbridge to reach a diplomatic resolution.

Keystone XL

The Alberta portion of the Keystone XL pipeline project consisted of 269 km, starting in Flagstaff County extending though the M.D. of Provost, Special Areas and Cypress County in southern Alberta. From there the pipeline would have continued into Saskatchewan and crossed the border through Montana, South Dakota and finally to Steele City, Nebraska. The Keystone XL Pipeline would have finalized the existing base Keystone Pipeline System. As of December 2020, 145 kilometres of pipe was installed in Alberta; the Canada-U.S. border segment was completed in April 2020 and construction in Saskatchewan was scheduled to begin in 2021.

Getting a cross-border pipeline built without government involvement has become increasingly challenging. The regulatory application for Keystone XL in Canada was approved by the Canada Energy Regulator in 2010. Since then, TC Energy obtained all required easements in Canada, and continued to conduct important project activities, including updates to environmental studies and ongoing stakeholder and Indigenous engagement. The project has long held widespread bipartisan support from U.S. lawmakers including all governors in the states the pipeline travels through. The pipeline is the most studied in American history and has been deemed safe and in the public interest through multiple state and federal reviews.

After the U.S. election outcome, TC Energy and the Government of Alberta continued to work to demonstrate the importance of Keystone XL to North American energy security and interdependence, as well as job creation to help with economic recovery on both sides of the border. However, the executive order which led to TC Energy suspending activity on the pipeline was signed by President Joe Biden in January 2021.



Source: Canadian Energy Regulator

Alberta's investment in this project was linked to our province's long-term economic interests, such as higher prices, as well as increased volumes of oil sands crude production, projected to generate at least $30 billion in increased royalties over 20 years for Alberta taxpayers. The project was projected to put 17,000 Canadians to work and generate billions of dollars of employment income for Canadian and US workers at a time when these increases would have helped recover from the economic downturn. The investment in the Keystone XL Expansion Project was valued at $106 million as at March 31, 2021. In addition, Alberta recorded a $1.04 billion debt guarantee provision for the year.

Federal Advocacy

To ensure better long-term value for Alberta crude and increased investment and jobs, the Government of Alberta continued to advocate for timely completion of major oil pipeline projects. Some actions included:

- Working with the Ministries of Justice and Solicitor General and Environment and Parks to defend Alberta's jurisdiction in the constitutional challenge of the *Impact Assessment Act* before the Alberta Court of Appeal. A decision is not expected until at least Fall 2021.

- Submission to the Minnesota Public Utilities Commission during the reconsideration phase for the revised Final Environmental Impact Statement, route permit, and certificate of need for the Enbridge Line 3 project.
- Submitted a letter to the U.S. Army Corps of Engineers, Omaha District, the South Dakota Department of Environment and Natural Resources, and the Nebraska Department of Environment and Energy in support of TC Energy's application for state certification 401 water permit for Keystone XL.
- Drafted a submission on behalf of the Government of Alberta to the Canada Energy Regulator in support of Trans Mountain Corporation's application for confidentiality of its insurers.
- Minister Savage testified at the House of Commons' Special Committee on the Economic Relationship between Canada and the United States on March 30 to discuss Enbridge's Line 5 pipeline and associated issues.

Economic Corridors

At the 2019 Council of the Federation summer meeting, Premiers agreed to explore the concept of pan-Canadian economic corridors. The Ministry of Energy worked with other departments across the Government of Alberta, as well as other provinces and territories over the course of several months to develop a report for the Council of the Federation. The draft report considers several aspects of economic corridors, including regulatory, governance, environmental, and social considerations. Unfortunately, due to other issues related to COVID-19, the report was not tabled for discussion at the 2020 meeting.

Building an Interprovincial Coalition of Provinces

The Ministry of Energy worked with provinces, territories, and the federal government through formal forums and ongoing bilateral relationships to make our energy industry a top priority. This included participation in the Energy and Mines Ministers' Conference and associated meetings, and related working groups focused on collaboration to advance new and emerging opportunities like the development of critical minerals; small modular reactors; and hydrogen.

Curtailment

In January 2019, the Government of Alberta implemented a policy that limited crude oil production to match takeaway capacity from the province. This was done to protect the value of the province's oil by helping prevent Canadian crude from selling at large discounts. The policy was to remain in place for one year until additional takeaway capacity in the form of additional pipelines and rail became available. In August 2019, due to continuing pipeline delays, the policy was extended by an additional year until December 31, 2020.

From December 2019 to November 2020, the oil production limit was maintained at a total of 3.81 million barrels per day. After March 2020, the economic impact of the COVID-19 pandemic caused operators to voluntary shut-in of production. In October 2020, due to continuing pipeline delays, the policy was extended by an additional year until December 31, 2021, as an insurance policy.

As of December 2020, monthly oil production limits are no longer in effect, with sufficient export capacity to allow the system to operate efficiently on its own throughout 2021. The Government of Alberta took the opportunity to put oil production limits on hold and industry can now produce and export oil via the rail or pipeline systems from the province at its discretion for the foreseeable future. Government will only put production limits back in place if there is a risk of inventories reaching maximum capacity and will give industry 30-to-60 days of advance notice to enable companies to plan their production. The department is closely monitoring production, storage inventories, pipeline capacity, and rail shipments as well as the global situation to ensure that production and take away capacity do not come out of balance.

Crude by Rail

In May 2019, the Alberta Petroleum Marketing Commission was tasked with divesting crude–by-rail contracts from government to the private sector. Contracts cover all aspects of the crude-by-rail program, including rail cars, buffer cars, inspection and delivery fees, railway tolls, terminals, storage tanks, loading at terminals, interconnection, various taxes, customs, cross-border fees, and logistics. In February 2020, the government was in the final stages of finalizing agreements to the private sector when the sudden crash in commodity prices occurred, brought on by COVID-19 and the Saudi Arabia, Russia and OPEC price war, which resulted in delays in assigning contracts. Unfortunately, market conditions have delayed the completion of the divestment process but the government continues to work through the process while negotiating the best possible terms for Albertans.

The crude-by-rail program was intended to ship an additional 120,000 barrels of oil per day from the province and was developed to ease market access issues associated with rising production volumes and a lack of pipeline take away capacity. To date contracts for shipment of 50,000 barrels of oil per day have been reassigned.

The current estimated cost of ending the program is $2.3 billion. As per the government's mid-year fiscal update in February 2021, the estimated cost of operating the program is between $2.3 and $2.7 billion. As such, divestment is expected to result in cost savings of up to $400 million.

Key Objective 1.2

Create an investment climate that supports the development of energy resources in the province, by:

- **reducing red tape and cumbersome regulatory processes.**
- **advocating for natural gas and liquefied natural gas to expand market opportunities, and implementing initiatives that support natural gas value chains,**
- **defending Alberta's energy industry through the Canadian Energy Centre, and**
- **addressing the report from the public inquiry into foreign sources of funds behind the anti-Alberta energy campaigns,**

Red Tape Reduction (RTR)

The Ministry of Energy is committed to the ongoing review of programs and services to ensure that the best possible outcomes are being achieved for Albertans. As part of this ongoing review, the ministry is committed to making life easier for hard-working Albertans and job creators by reducing regulatory requirements by one-third by 2023, and eliminating administrative burden through more efficient processes. This work will improve service delivery for Albertans; foster economic growth, innovation and competitiveness; create a strong and attractive investment climate; and make Alberta one of the freest and fastest moving economies in North America.

Red Tape Reduction aims to identify, reduce, and eliminate processes that cause regulatory and administrative burdens for all Albertans. The aim of government's RTR policy is to establish a clear policy intent and method for identifying and reducing unnecessary regulatory burdens while maintaining consumer, environmental, health and safety protections, and fiscal accountability. This work is undertaken with the goal of implementing change that promotes job creation, innovation, and competitiveness; facilitates a strong and attractive investment climate in Alberta; and preserves and promotes public safety.

In 2019, the Ministry of Energy and its agencies established a baseline count of 110,838 regulatory requirements, including statutes, regulations, and associated forms and guidelines requiring compliance. The ministry has been working towards achieving the interim reduction targets of five per cent by March 31, 2020; 12 per cent by March 31, 2021; 20 per cent by March 31, 2022; and 33 per cent by March 31, 2023.

The Ministry of Energy is undertaking a one-ministry approach to red tape reduction to ensure alignment between the department and its agencies, boards and commissions that have shared accountability over the management of Alberta's energy and mineral resources.

To date, the Ministry of Energy has completed a number of significant RTR initiatives to address regulatory burdens that benefit the oil, gas and electricity industries, including:

- Simplified processes for oil sands lease holders by reducing the requirements for renewing or converting their leases, and removing a step in new oil sands approvals. These changes will save companies time and resources, and reduce land disturbance.
- Streamlined requirements for the oil and gas industry`s venting and flaring, which removed obsolete and duplicate requirements. This change resulted in less administrative burden for industry in their reporting to government.
- Created a royalty rate for helium, allowing Alberta to become more competitive in attracting helium producers to the province. Lowered the deposit amount new electricity retailers need to pay, lowering the barrier to entry to the retail electricity market and paving the way for greater consumer choice.

The ministry's RTR initiatives have resulted in substantial cost savings for industry. For example, the Alberta Energy Regulator's updated directive for Water Disposal Limits and Reporting Requirements for Thermal In Situ Oil Sands Schemes could yield collective costs savings of up to $273 million for existing projects as per a CAPP estimate. The ministry also regularly engages with industry stakeholders through working groups and industry panels to better understand and address their recommendations.

The ministry has achieved a 15 per cent reduction in red tape, surpassing the Ministry's interim target of 12 per cent for 2020-21.The Ministry of Energy continues to solicit project ideas and prioritize initiatives to achieve RTR goals and to address industry and public RTR recommendations.

Natural Gas Vision and Strategy

The Government of Alberta has prioritized the revitalization of Alberta's natural gas industry. Utilizing the recommendations of the 2018 Roadmap to Recovery report and an extensive engagement process with Indigenous, municipal and industry stakeholders across the value chain, the Ministry of Energy released a forward-looking Natural Gas Vision and Strategy in October 2020 that is a key part of Alberta's Recovery Plan. The vision and strategy identifies short-, medium- and long-term actions to sustain and support natural gas, including emerging energy transition opportunities that support future value chain growth and development and align with global climate goals and commitments. In some cases, technology to commercialize these opportunities are not as economically competitive in the short- to medium-term, but long-term gains continue to be made. Alberta sees an opportunity to take a leadership role in this evolving global energy system. To achieve this, a vision and strategy for the future of natural gas was required. The full Natural Gas Vision and Strategy can be viewed at www.alberta.ca.

Key areas of work underway in 2020-21 included initiatives related to advancing a plastics circular economy, liquified natural gas, hydrogen, and the Alberta Petrochemical Incentive Program described below.

Plastics Circular Economy

Government is collaborating with industry and academia to innovate and create a plastics circular economy in the province. A plastics circular economy is established when the full value of a plastic product is used across multiple lifecycles – not just used once and discarded into landfills or waterways.

In 2020, the Ministry of Energy, Ministry of Environment and Parks, NAIT and the Recycling Council of Alberta established the Plastics Alliance of Alberta (PAA). The PAA is a collaborative initiative that brings together stakeholders who have technical knowledge and environmental insight to make Alberta a hub for innovative plastics management.

Alberta's goal is to be established as the Western North America centre of excellence for plastics diversion and recycling by 2030. According to a report by Environment and Climate Change Canada, 86 per cent of plastics were landfilled in 2016. This represents a $7.8 billion lost opportunity. A study completed by Eunomia Research and Consulting indicated 4,500 direct full-time equivalent jobs are created in the province as a result of existing recycling activities, with a further 1,600 indirect and 1,400 induced jobs, for a total of 7,500 jobs. Increasing recycling in the province has the potential to create an additional 13,300 jobs and $1.4 billion dollars in economic activity.

Liquefied Natural Gas (LNG)

Work with federal and provincial representatives to ensure LNG can reach the necessary markets is also ongoing. In Canada, as of May 2021 there is one LNG project, the LNG Canada phase one, under construction. It is slated for completion in 2025. Securing a second world-scale west coast LNG project was the first of 48 recommendations found in the report.

The Ministry of Energy continues to explore options to advance LNG projects with government partners to utilize Alberta natural gas as feedstock.

What is Liquefied Natural Gas (LNG)?

- LNG is natural gas in its liquid state. When natural gas is chilled to a temperature of about minus 160° C (minus 260° F) at atmospheric pressure, it becomes a clear, colourless and odourless liquid.
- LNG is non-corrosive and non-toxic. However, due to its extreme cold nature, it must be carefully manufactured and stored.
- The liquefaction process removes water, oxygen, carbon dioxide and sulfur compounds contained in the natural gas. This results in an LNG composition of mostly methane with small amounts of other hydrocarbons and nitrogen.
- As a liquid, natural gas is reduced to 1/600th of its original volume. This makes it feasible and economical to transport over long distances in specially designed ocean tankers. Once received, the LNG goes into storage tanks, is re-gasified, and delivered to markets. (Source: NRCan)

Hydrogen

Developing a robust clean hydrogen economy can unlock significant economic value for Alberta and Canada, while advancing critical environmental outcomes. Deploying hydrogen into the transportation and home heating sectors, and incorporating it as fuel for electricity generation and other industrial processes, is key to Canada's ability to meet greenhouse gas reduction targets under the Paris Accord. Growing demand for hydrogen provides Alberta with a new strategic opportunity to expand and integrate its natural gas value chain. This will benefit Albertans, Canadians and the world by creating jobs, generating government revenue and contributing clean fuel to the global economy.

In 2020, the Ministry of Energy launched a targeted engagement process to help inform the engagement and development of a hydrogen roadmap for Alberta. Over the six-month process, the department met with more than 100 organizations from industry, association, Indigenous representatives, academia and municipalities. The roadmap will to help Alberta reach its strategic goals on hydrogen to have large-scale hydrogen production with carbon capture, utilization and storage and deployment in various commercial applications across the provincial economy by 2030, and to have exports of clean hydrogen and hydrogen-derived products to jurisdictions across Canada, North America and globally in place by 2040.

Alberta contributed to the federal government's hydrogen strategy, released in December 2020, which supports the work the ministry is doing to build a provincial hydrogen roadmap. As a province central to Canada's efforts to build a globally ground-breaking clean hydrogen sector, the Government of Alberta supports Ottawa's work on a collaborative strategy that will rely on our industry's experience and expertise in natural resource production and emissions reduction technology.

What is the difference between Blue and Green Hydrogen?

Alberta has distinct advantages in producing hydrogen from natural gas with carbon capture, utilization and storage. This production pathway is called blue hydrogen, while green hydrogen is produced through non-fossil fuel sources.

Alberta's hydrogen roadmap will focus on the carbon intensity of hydrogen instead of colour pathways, which aligns with the federal government's hydrogen strategy. Alberta's approach to hydrogen production is technology-agnostic, meaning the province will support both "blue" and "green" hydrogen production pathways that result in low-carbon hydrogen. Hydrogen produced from natural gas with carbon capture and storage is presently the most cost-competitive compared to other large-scale clean hydrogen production, and is considered an enabler of green hydrogen at a later stage. The Government of Alberta is providing clear messaging to inform that blue hydrogen is needed to reduce carbon emissions.

Alberta Petrochemical Incentive Program (APIP)

The APIP launched on October 30, 2020 with the intent of propelling Alberta to become a global leader in petrochemical production, bringing long-term investments, and thousands of jobs to the province. The program was designed based on input from stakeholder engagements with regional industry associations, previous Petrochemical Diversification Program (PDP) applicants, and petrochemical investors. Compared to previous government petrochemical programs, the Alberta Petrochemicals Incentive Program will cut red tape and increase certainty and flexibility for investors, attracting more financial investment into Alberta's petrochemicals sector.

Alberta has a tremendous opportunity to capitalize on the growing global petrochemical sector and diversify the province's economy, with our abundant natural gas reserves and a competitive, investor-friendly business environment. Sitting on top of the Western Canadian Sedimentary Basin, Alberta has potential reserves of 223 trillion cubic feet, representing a multi-generational supply of gas deposits.

Petrochemicals are already Alberta's largest manufacturing sector, with over 50,000 people employed directly and indirectly by the industry.

There is an opportunity to grow Alberta's petrochemical sector by more than $30 billion by 2030, resulting in more than 90,000 direct and indirect jobs over the construction and operation periods of new facilities. The Ministry of Energy worked with industry, potential investors, and regional associations to create a streamlined market-based program that is competitive, easy to understand, and straightforward to administer. APIP is a simple, more direct, and focused program, with direct financial incentives on the largest cost component of these types of facilities: the capital investments. The program runs without unnecessary red tape by following a process where all the applicants to the APIP will receive funding as long as they meet the eligibility requirements.

APIP is a key pillar of the Natural Gas Strategy and Vision and an early success of that strategy. Due to the changing dynamics in the energy sector and alignment with the government's intent of diversification, the program's scope was broadened compared to the previous PDP. Unlike PDP, APIP is open to almost all types of petrochemicals, hydrogen, fertilizer, and fuel plants as long as the eligibility criteria are met.

Risk to government is mitigated, as grants will not be provided to companies until their projects are operational and successfully consuming feedstock. The economic benefits of building a stronger, long-lasting, and self-sustaining petrochemical industry in Alberta will more than offset the initial cost of providing the grants to companies willing to invest in Alberta. The projects that would be approved under APIP represent millions of dollars in government revenue, thousands of construction jobs, and hundreds of high-skilled jobs once operational.

The program requires smaller scale projects with a capital investment of $50 million to $150 million to apply to the program and become operation by 2025. For projects over $150 million the program will be open for another 10 years and interested companies would be able to apply and become operational by 2030 to receive funding. The department received its first application under APIP just a month after launching the program in November 2020. Since the launch of the program, the department has received significant interest and received multiple applications from local and international investors.

Did you know…

Unlike in other sectors, demand for petrochemical products has not slowed down in the face of the COVID-19 pandemic – in fact, the need for petrochemical products has never been greater. The pandemic has demonstrated the critical importance of the sector in ensuring there is a sufficient supply of plastic masks, gloves, medical equipment and shielding to help keep medical professional and frontline workers safe.

Aside from these products, petrochemical facilities help to ensure that people around the world have access to many other essential items that make our lives safer, healthier and more convenient, including:

- packaging that keeps food fresh and safe
- medical supplies, such as computers for x-rays and MRIs and personal protective equipment, including face shields and gowns
- polyester fabric couches, HD televisions, phones, bicycle helmets, coffeemakers and computers
- car tires, engine hoses, radio components and seats
- desks, chairs, computers, carpets, cellphones and other office supplies

Petrochemical Diversification Program (PDP)

PDP was originally launched in 2016 to enable construction of new and expanded petrochemical facilities in the province by providing royalty credits to encourage companies to build manufacturing facilities that turn ethane, methane and propane feedstock into products that have more value than the raw materials. These valuable products include plastics, fabrics, fuels and fertilizers. Under the program, approved projects are issued royalty credits once the facilities become operational.

In 2016, the previous Alberta government committed $500 million in future royalty credits as part of the first round of the PDP, and two projects were approved: Inter Pipeline was approved to receive up to $200 million in royalty credits for its Propane Dehydrogenation facility; and the Canada Kuwait Petrochemical Corporation (CKPC) was approved to receive up to $300 million in royalty credits for its integrated petrochemical complex. Both projects would process propane into polypropylene plastic and represent a new value chain for the province and Canada.

- Approximately $3.2 billion has been spent by Inter Pipeline on the Heartland Petrochemical Complex to December 31, 2020. For the third and fourth quarters of 2020, site construction focused on major equipment packages installation. More than 150 Alberta-based and nearly 30 other Canadian-based companies working directly on engineering and construction of the project. Project completion and commissioning of the complex is scheduled for early 2022.
- Throughout 2020, CKPC continued to evaluate a number of factors related to their project. These included, but were not limited to understanding the future and ongoing risks so they could be priced into the project cost estimate and assessing the full impact of COVID-19 on the global economy and the uncertain future demand of polypropylene. In December 2020, the partners made the decision to indefinitely suspend the project based on this continued evaluation of the risks facing the project. Any future project restart is subject to CKPC Management Committee approval and each partners' board approval.

In 2018, the previous government also announced $1.1 billion in royalty credits for a second round of the PDP program. Two projects were approved to receive a combined total of $150 million in royalty credits: up to $80 million for Nauticol Energy Ltd. to construct a methanol facility near Grande Prairie, and up to $70 million for Inter-Pipeline to build a facility that would process propylene into acrylic acid in Alberta's Industrial Heartland.

- In March 2021, Nauticol Energy announced it has teamed up with Fortrec to create a new Singapore based company that will develop, construct and operate a multi-billion-dollar World Scale, Net Zero, Blue Methanol facility in Alberta, Canada and distribute Blue Methanol worth over $1 billion annually through its Singapore trading platform.

Carbon Capture, Utilization and Storage (CCUS)

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

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

In December 2020 and January 2021, the Ministry of Energy engaged with stakeholders on the topic of CCUS and its role in clean hydrogen production. These stakeholders included industry, academia, and non-government organizations. Through the hydrogen roadmap engagement, stakeholders expressed that CCUS was integral to the development of hydrogen production in the province, and that certainty on the regulatory framework was essential to moving forward. Alberta is in an excellent position to develop more CCUS due to our geology, and due to the experience industry already has in the natural resource industry.

In March 2021 the province and the federal governments announced a CCUS working group that – guided by the Alberta energy sector's expertise and experience – will advance efforts to reduce emissions, diversify the economy and create jobs. The group will explore opportunities for CCUS technology and help determine how Alberta can lead the way in establishing Canada as a global leader in emissions reduction technology. The ingenuity of Alberta's energy sector combined with the province's geological capacity to store carbon – and the federal government's commitment to invest in CCUS – is a winning combination.

Carbon Capture and Storage Program

In 2008, the Government of Alberta committed $2 billion to establish a Carbon Capture and Storage Program Fund to incent the development of CCS large-scale projects in Alberta, with the objective of storing up to five million tonnes of carbon dioxide per year and reducing overall greenhouse gas emissions. Through a comprehensive selection process, four projects were chosen to receive the allocated funding; however, only two projects decided to proceed with their plans: the Quest and the Alberta Carbon Trunk Line projects.

For these two projects, $1.24 billion in funding allocated to the end of 2025 to capture approximately 2.76 million tonnes of carbon dioxide each year. This is roughly equivalent to annual emissions of 600,000 vehicles.

Yearly presentations and annual reports are also completed by Quest and the Alberta Carbon Trunk Line. Project learnings are shared through a knowledge sharing program that helps to reduce the future costs of CCUS and the broader adoption of this technology around the world – summary and detailed reports for the knowledge sharing program are submitted annually on or before April 1. These reports are available at www.alberta.ca.

Previous work by the Government of Alberta on CCUS includes the 2008 Carbon Capture and Storage Program Fund, which continues to realize benefits for Albertans. Over the 2020-21 fiscal year, commercial operation payments for the Alberta Carbon Trunk Line project and an injection payment to the Quest project totaled approximately $126 million. The funding provided to two projects will allow them to capture up to a combined 2.76 million tonnes of carbon dioxide per year. The amount of the greenhouse gas emission reductions are certified by third-party verifiers.

- Quest Project Update: The Quest project is capturing approximately a million tonnes of carbon dioxide per year from the Shell Scotford Upgrader, transporting it 65 km north by pipeline and permanently storing it underground in a deep saline aquifer. On July 10, 2020, it was announced that the Quest project had injected over five million tonnes of carbon dioxide in less than five years. This was faster than anticipated and at a lower cost. The 2020 versions of the Quest project's Measurement, Monitoring,

The Post-Closure Stewardship Fund

The Post-Closure Stewardship Fund is administered by the department and financed by carbon capture, and storage operators in Alberta. The fund will help ensure that the storage sites are properly maintained, over the long term, after operations cease.

Those operators that obtain a lease under the Carbon Sequestration Tenure Regulation are required to contribute to the fund. The amount paid into the fund is based on a project-specific rate per tonne of carbon dioxide injected into the sequestration lease each year. To date, the Post-Closure Stewardship Fund has collected five annual injection levy payments from the Quest project.

and Verification Plan and Closure Plan were approved by Alberta Energy in November 2020. These plans describe the surveillance activities necessary for ensuring the safe and reliable operation of a carbon sequestration project. They will be in effect for up to three years, when new versions must be submitted for review and approval.

- Alberta Carbon Trunk Line Project Update: The Alberta Carbon Trunk Line project, which achieved commercial operation in May 2020, will transport approximately 1.7 million tonnes of carbon dioxide captured from the North West Sturgeon Refinery and the Nutrien Redwater Fertilizer Plant each year, through a 240-km pipeline, for use in enhanced oil recovery in Clive, Alberta. The pipeline has the potential to transport up to 14.6 million tonnes of carbon dioxide annually. On March 9, 2021, the Alberta Carbon Trunk Line project announced that it had already injected over one million tonnes of carbon dioxide into its Clive oilfield.

Technology Innovation and Emissions Reduction (TIER)

The Technology Innovation and Emissions Reduction Regulation — is Alberta's industrial greenhouse gas emissions pricing regulation and emissions trading system. The Ministry of Energy supported the Ministry of Environment and Parks in the development and implementation of the TIER Regulation, which came into force on January 1, 2020 replacing the Carbon Competitiveness Incentive Regulation.

The government is investing up to $750 million from the Technology Innovation and Emissions Reduction—or TIER—fund and other public funding on a series of programs that will get Albertans back to work and reduce emissions. Facilities that reduce emissions beyond their benchmark can generate emissions performance credits. Facilities that do not directly meet their benchmark can comply in one of three ways:

- Submit Alberta emission offsets generated from qualifying emissions reductions outside of regulated facilities;
- Submit emissions performance credits; or
- Obtain fund credits by paying the prescribed price into the TIER fund.

The TIER fund supports the advancement of technology and innovation while providing incentives to increase compliance and decrease overall emissions through:

- Methane Technology Implementation Program is a $25 million program to support installation of readily available methane reduction technologies at conventional oil and gas facilities.
- Baseline Reduction Opportunity Assessment Program is a $10 million program to support small and medium-sized oil and gas operators to conduct detailed assessments of methane reduction opportunities and fugitive emissions.
- Fugitive Emissions Management Program supports investigating and testing alternative approaches to detection and quantification of fugitive and vented emissions.
- Emission Reduction Alberta and Alberta Innovates: Supports various methane emissions detection and reduction projects and initiatives.

With a downturn in the market and the rationalization in production, TIER fund managers continue to collaborate across departments, ensuring that Alberta is supporting technology innovation that will assist in reducing overall emissions and achieving targeted reductions. With a strong commitment to energy advocacy, the establishment of the ESG Secretariat using TIER funding will help Alberta inform Canadians and people across the globe about how Albertans produce energy with the world's highest environmental, social, and governance standards.

Environmental and Social Governance (ESG)

Since 2019, the Government of Alberta has conducted targeted engagement with investors, insurers, banks, governments, industry and research organizations on how the integration of ESG practices into institutional investment decision-making is putting pressure on investors and companies to divest from Alberta's oil sands. This, in addition to ongoing policy research and analysis of actions taken by other jurisdictions, has formed the basis of how the department is responding to the rise in ESG scrutiny and will determine what action is needed to keep Alberta a leader in the ESG space.

In partnership with other departments, action has been taken to develop effective advocacy plans and materials to support conversations with investors, and to push back against divestments in the energy sector.

In March 2021, Premier Kenney announced the creation of a secretariat to coordinate and integrate ESG-related work across the Government of Alberta that will be housed in the Ministry of Executive Council. The Ministry of Energy will continue to support ESG efforts to help stop divestment from the oil sands and the Canadian energy sector.

Sturgeon Refinery

Sanctioned in 2012, the objective of the Sturgeon Refinery was to process bitumen into diesel and other value added products. The Government of Alberta has a binding 30-year commitment to provide bitumen that will be processed into refined products – primarily ultra-low sulphur diesel – and in return pay a cost-of-service toll to the North West Redwater Partnership (NWRP). The Sturgeon Refinery has the potential to add value to the resources Albertans own and further demonstrate Alberta's expertise in commercial-scale carbon capture and storage.

Starting November 2017, the Sturgeon Refinery was processing synthetic crude oil into diesel and other valuable products as part of the commissioning and start up process. The refinery reached commercial operations on June 1, 2020 and at that point processed bitumen into diesel.

- total diesel production was 11 million barrels in 2019; and
- total diesel production reached 11.8 million barrels in 2020.

The refinery has a capacity of 79,000 barrels per day of feedstock increasing total Alberta refinery capacity to 533,000 barrels per day.

Sturgeon Refinery has the potential to add value to the resources Albertans own and further demonstrate Alberta's expertise in commercial-scale carbon capture and storage. The refinery is producing low carbon diesel and has added a significant number of well-paying jobs to the economy. The refinery provides more than 400 jobs related to the long-term operation of the facility as well as other well-paying jobs in the economy.

For 2020-21, the non-cash loss provision is $2.5 billion based upon net present value calculations. This figure represented a snapshot in time, and was negatively impacted by a variety of recent market conditions – led by deflated commodity prices, currency exchange rates and the duration of planned facility turnarounds being longer than expected. The net present value is calculated on an annual basis. In the event it changes, government will adjust estimates accordingly through its standard financial reporting process.

To date, APMC has borrowed $335 million from Treasury Board and Finance to lend to the refinery, with the commission obtaining 25 per cent voting interest in the NWRP Executive Committee while the loan is outstanding.

Returns will be predominately affected by commodity prices for refined products and feedstock and foreign exchange. In addition returns will be impacted by how well the refinery operates, as measured by the on-stream factor.

Canadian Energy Centre (CEC)

The Government of Alberta established the Canadian Energy Centre as an independent provincial corporation under the *Financial Administration Act*. Its mandate is to promote Canada as the supplier of choice for the world's growing demand for responsibly produced energy.

Canada's energy sector is under increased public scrutiny from both the investment community and a number of well-funded and well-organized anti-fossil fuel groups. To date, these groups have been effective at misrepresenting the sector's environmental performance. In response, the CEC fights for Canada's energy sector —and the hundreds of thousands of people it employs.

The CEC responded to misinformation about Canadian oil and natural gas; created original content to elevate the general understanding of Canada's energy sector to help the country take control of its energy story; and centralized and analysed data that targets investors, researchers, and policy makers. A key priority for government is to inform Canadians and citizens around the world about how Canadian energy is produced with the world's highest environmental, social, and governance standards.

Engaging with and educating Canadians about Alberta's natural resource development is the first step in ensuring that the sector's economic potential is achieved to the benefit of the entire country.

The CEC worked to build national and international support and awareness to provide a stable environment for continued investment, job creation, and economic recovery. The CEC continued its "When We Work, Canada Works" campaign across Canada, highlighting pipelines, economic growth, jobs, and tax revenues as part of a longer term strategy supporting COVID-19 economic recovery. The campaign included billboards and advertising on news sites and radio stations across Canada.

Since summer 2020, more than 20,000 Canadians took part in CEC digital campaigns, including:

- A letter writing campaign resulting in almost 2,000 letters in less than 48 hours to federal Members of Parliament across Canada calling on them to stand up for Canadian pipeline projects, in light of intensified attacks by opponents.
- An open letter to the Prime Minister and Premiers on the role of the oil and gas industry in the recovery from COVID-19.
- An open letter to the Prime Minister asking him to call Joe Biden and stand up for Keystone XL.
- A letter-writing campaign to Regina City Council in response to a policy proposal that would have prevented oil and gas companies from sponsoring city events. Over a 48-hour period, Regina's mayor and councillors each received more than 2,000 emails from Canadians asking them not to move forward with the policy. In the end, Regina city council voted unanimously against it.

The CEC continues to grow its network across Canada and around the world. The CEC website hosts thousands of visitors from outside Canada, and its original content is used by third-party organizations. The CEC reaches a million people a month on its Facebook page.

In March 2020, the government announced the CEC had reduced its spending and scaled back activities to responsibly manage expenses during the global pandemic. During 2020-21, the cost of CEC activities were $3.7 million. These activities included salaries, administrative costs, and the development and execution of a digital marketing campaign.

Public Inquiry

For over a decade, an alleged, well-funded foreign campaign has defamed Alberta's energy industry and sought to land-lock the province's oil. The reputational harm to the province's energy sector is alleged to have robbed the people of Alberta of billions of dollars in lost revenues and thousands of jobs.

In July 2019, the Government of Alberta launched an independent public inquiry, under the Public Inquiries Act, into the existence of a well-funded foreign campaign aimed at discrediting Alberta's energy sector. Steve Allan, a Calgary forensic and restructuring accountant with 40 years of experience, was appointed as commissioner to lead the inquiry.

The commissioner's mandate directed him to examine investigations completed by other jurisdictions into similar activities or alleged activities, make recommendations to assist the Government of Alberta to respond effectively to any anti-Alberta energy campaigns, and consider additional eligibility criteria for government grants or charitable status. The commissioner completed an interim report, and determined additional time and effort was needed to complete a final report – and to fairly and justly complete his inquiry process. The final report is to be submitted to the Minister of Energy no later than July 31, 2021.

The total cost of the inquiry was $3.5 million, including $2.5 million announced in July 2019 and an additional $1 million, announced in June 2020.

Electricity

Effective operation of Alberta's electricity system is critical to support the province's economic recovery from COVID-19. In 2019, Alberta confirmed its commitment to the energy-only market construct for power generation in the province. This policy clarity, coupled with policy certainty created by the Technology and Emissions Reduction Regulation, led by the Ministry of Environment and Parks, provide the necessary conditions for private investors to advance new generation projects in the province.

Did you know…

Empowered through Alberta's commitment to an energy-only market, combined with our legal and legislative framework, the province is poised to benefit from the evolution of the global electricity sector. The Canada Energy Regulator has recently forecasted that Alberta will be Canada's leader in growing renewable energy capacity over the next three years.

Most importantly, Alberta's significant growth in market-based renewable energy is by private investors, not government subsidies – meaning there is no associated public debt.

The benefits of this approach show in the more than $5 billion in investment announced for generation projects – including more than $2 billion for utility-scale renewable projects - since July 2019.

Through government's on-going work with the Alberta Utilities Commission to further modernize our electricity system, Alberta's electricity sector has the foundation it needs to adopt emerging technologies, providing stability to investors and driving competitive pricing for consumers.

Actions taken to reinforce Alberta's energy only electricity market and the implementation of the Technology and Emissions Reduction (TIER) regulation resulted in announced investments of $2.64 billion of natural gas generation and $646 million in renewable generation. This represents 2,464 megawatts of natural gas generation, 234 megawatts of solar generation, and 151 megawatts of new wind generation.

The Ministry of Energy completed a review of the electricity agencies - the Market Surveillance Administrator, Alberta Utilities Commission, Utilities Consumer Advocate, and Balancing Pool - to identify opportunities for improved efficiency and effectiveness. The work, completed in fall 2020, was done in conjunction with the broader red tape reduction initiative and was conducted with the objective of enhancing the ability of electricity developers to more efficiently navigate Alberta's electricity system.

The Government of Alberta is committed to maintaining a safe, reliable and affordable electricity system for all Albertans. This means working with stakeholders to determine where the system needs to be modernized to meet the needs of consumers and investors. Government recognizes the need to address identified gaps in the current legislative framework, which may limit the adoption of technical innovations and create uncertainty for investors, our electricity agencies, and Albertans and are engaging with impacted stakeholders – including associations, utility companies and other interested organizations – to better understand the nuanced perspectives that impact policy decisions in this sector. The focus is on enabling policy that optimizes use of the current system, ensuring an efficient and cost effective future system, and maintaining investor confidence in Alberta's electricity sector.

Additional Achievements:

Site Rehabilitation Program (SRP)

The SRP launched on May 1, 2020, accessing up to $1 billion from the Government of Canada's COVID-19 Economic Recovery Plan, provides relief funding to eligible oil field service workers to perform well, pipeline, and oil and gas site closure and reclamation work. The SRP supports economic recovery by increasing employment in the oilfield service sector and enhancing Alberta's investment climate, while also decreasing the environmental liability associated with oil and gas development. The SRP is expected to generate almost 5,300 direct jobs and lead to indirect employment and economic benefits across the province, as other businesses will benefit from the increased clean-up work occurring in many rural areas.

Grant funding was made available in six periods in 2020-21, each with targeted priorities, application criteria, and timelines:

- Period one made $100 million in funding available from May 1, 2020 to May 15, 2021. Grant applications were accepted for oil and gas sites needing abandonment and/or reclamation across Alberta for projects that required 100 per cent government funding with contracts of up to $30,000 (per application, per closure activity). As period two was not fully subscribed, $83.1 million of available funding was reallocated to period one, and a total of $183.1 million in funding was allocated.
- Period two made $100 million in funding available from May 15, 2020 to June 15, 2020. Grant applications were accepted for oil and gas sites on land where government is paying compensation to landowners as required under Section 36 of the *Surface Rights Act* for projects that require 100 per cent government funding, with no contract cost limit. Of the available funding, $15.4 million in funding was allocated to 63 companies, with another $83.1 million reallocated to period one.
- Period three made $100 million in funding available from July 17, 2020 to March 31, 2021, or until licensees fully expended their allocations. Grant applications were accepted for up to $139,000 in funding for each active site licensee in the province. Oil field service contractors could contract with these licensees to do closure work and apply for an SRP grant to get funding to do the work and were eligible for 100 per cent grant funding. Of the funding available, $54.1 million in funding was allocated to 279 companies.
- Period four made $100 million in funding available from August 7, 2020 to September 30, 2021, or until licensees fully expend their allocations. Grant applications are accepted for licensees who have submitted either confirmed or proposed Area-Based Closure plans to the Alberta Energy Regulator. Projects are eligible for up to 50 per cent grant funding, with the licensee responsible for paying the remaining

amount. Grant funding is increased up to 100 per cent of the project value if the licensee contracts with Indigenous oil field service companies. As of March 31, 2021, $84 million of the available funding was allocated to 209 companies.

- Period five made $300 million in funding available from February 2021 to March 31, 2022, or until allocations are fully subscribed. Licensees with confirmed hydrocarbon production in 2019, and that spent corporate funds doing closure work in 2019 or 2020, have been allocated SRP grant funding amounts for period five. Projects are eligible for up to 50 per cent grant funding. Grant funding will be increased up to 100 per cent of the project value if contracted with Indigenous oil field service companies. As of March 31, 2021, $3.8 million of the available funding was allocated to 26 companies.
- Period six made $100 million in funding available from February 12, 2021 to March 31, 2022, or until allocations are fully subscribed. First Nations that have each been allocated a portion of $85 million in SRP closure funding, and Metis Settlements have each been allocated a portion of $15 million in SRP closure funding, to work with licensees and applicants to close sites on reserve and on settlement. Out of these total allocations, each First Nations allocations were developed in cooperation with the Alberta member First Nations of the Indian Resource Council and are distributed based on the number of eligible well licenses on each First Nations reserve, in proportion to the total number of eligible wells in all First Nations where eligible wells are located. Metis Settlements allocations were developed in cooperation with the Metis Settlements General Council office and are distributed based on the number of eligible well licenses on each Settlement, in proportion to the total number of eligible well licenses on all Settlements. First Nations communities and Metis Settlements will approve the sites that are eligible for closure work using their allocation, and will work with licensees and contractors to approve the associated spending. Once this is done, the First Nations and Metis Settlements will inform the Ministry of Energy which licensees are eligible for SRP funding, and for how much. Contractors can then apply directly to government for SRP grants to do the work. As of March 31, 2021, $3 million of the available funding was allocated to two companies.

As of March 31, 2021, over $343.4 million in grant funding has been approved and is being allocated to 502 Alberta-based companies, creating nearly 1,600 jobs so far. A total of 18,444 applications have been approved. Of the total approved, $220.4 million has been allocated for 14,364 abandonment sites, $34.4 million has been allocated for 6,241 Phase 1 environmental site assessments, $27.0 million has been allocated for 1,747 Phase 2 environmental site assessments, $14.7 million has been allocated for 426 remediation sites and $46.9 million has been allocated for 3,597 reclamation sites.

Taking an incremental approach to making the funding available through different periods was critical to success, allowing feedback and lessons learned to be incorporated into each round. The speed of the rollout of the program and manual review in the initial periods of the program provided valuable learning for future periods.

For more information on the SRP, visit: www.alberta.ca.

Minerals and Metals

Alberta has geological potential across the province for non-energy minerals, many of which have been identified as critical and strategic minerals – such as lithium in formation waters in south-central and west-central Alberta; vanadium, rare earth elements and titanium in oil sands waste streams; potash in eastern Alberta; and uranium in southern and northeastern Alberta.

In 2020, the Ministry of Energy led efforts to make Alberta an attractive place for mineral exploration and development. The work serves as part of government's economic recovery efforts to re-launch and diversify

Alberta's economy and secure long-term prosperity in response to the COVID-19 pandemic and economic downturn.

In April 2020, the Government of Alberta endorsed the draft plan and established the Mineral Advisory Council (MAC) to offer strategic advice, guidance, and recommendations throughout the stakeholder engagement process. The MAC consists of members representing key stakeholders in the minerals industry across Canada and internationally, or members who have senior or executive leadership experience in geology, resource development, Indigenous relations, regulatory and environmental affairs, and investor and industry perspectives.

Solid fundamentals for developing minerals in Alberta

Home to a well-established oil and gas and mining sector, Alberta already has a skilled workforce with experience in resource development, a well-defined and stringent regulatory system, and the necessary infrastructure in place to support an expanded and growing minerals sector.

Companies in Alberta are already working to develop innovative processes to extract minerals from oilfield brine and oil sands waste streams, including froth treatment tailings.

Alberta's current non-energy mineral production comes primarily from 20-plus active quarries producing salt, silica sand, limestone and other industrial minerals. There is a small amount of gold production reported as a byproduct of sand and gravel operations.

The stakeholder engagements were conducted in two phases. Phase one was an online survey from October to November 2020. The survey population was approximately 200 organizations and groups which included representatives from industry, Indigenous groups, landowner groups, environmental non-governmental organizations, provincial and federal governments and government agencies.

Phase two occurred in January 2021 and included virtual roundtables with key industry groups and other stakeholder groups who expressed interest during the phase one online survey. This second phase focused on the mineral regulatory regime and mineral tenure.

The survey and roundtable engagement identified cross-sector support for developing a strategic plan to grow Alberta's minerals sector and making the province a destination of choice for mineral investment. In addition, stakeholders were generally supportive of updating Alberta's mineral regulatory to support stronger regulatory integration and advancing development of emerging resource opportunities. Overall, stakeholders identified that responsible development of Alberta's mineral resources needs to be undertaken. Engagement looked at key areas, such as improving public access to quality data about mineral occurrences in Alberta, having a streamlined regulatory environment in place that assures environmentally responsible development, enhancing opportunities for Indigenous peoples and promoting innovation. Engagement with stakeholders and Indigenous communities also provided an opportunity to share information and raise awareness about Alberta's mineral opportunities. In addition, cross-ministry engagement also identified key linkages with other government initiatives to ensure alignment to support Alberta's economic recovery efforts as part of the response to the COVID-19 pandemic.

Alberta's minerals strategy will build on the province's involvement with the Canadian Minerals and Metals Plan. The government has been working with the federal and other provincial and territorial governments, through the Critical Minerals and Battery Value Chain Task Force, in pursuing Canada's approach to targeting the critical minerals and battery value chains. This is a part of the federal strategy and action plan developed in 2020. Natural Resources Canada announced Canada's critical minerals list as part of the initiative at the Prospectors and Developers Association of Canada Convention 2021. This critical minerals initiative, as well as other pan-Canadian initiatives under the Canadian Minerals and Metals Plan will help advocate for

Alberta's minerals opportunities, raise awareness around Alberta government's initiatives, and position Alberta as a potential mineral supplier and manufacturer along the critical minerals value chains. In addition, the Ministry of Energy has been working with the federal and other provincial and territorial governments, in implementing a number of flagship pan-Canadian initiatives under the Canadian Minerals and Metals Plan and developing Canada's action plan for critical minerals.

While Alberta is developing its own Minerals Strategy and Action Plan, inter-governmental collaboration, including with the federal government, is identified as one of the key factors in promoting Alberta's minerals development. The actions the federal government is taking, in order to pursue their vision of Canada as a leading mining nation, present opportunities for Alberta and other Canadian jurisdictions to enhance the competitiveness of their respective mineral sectors.

Geothermal

The Ministry of Energy has been taking a deep dive to attract new investment in geothermal energy as it continues to diversify the province's energy sector. Developing this resource helps diversify Alberta's energy sector and provide electricity and heat to municipalities, industry and remote areas of the province.

Geothermal energy is the natural heat that originates from the Earth. It can be used for heating and cooling or to generate clean electricity. Research from the University of Alberta has identified potential to develop this resource on a commercial scale with more than 6,100 megawatts of thermal power capacity potential and more than 1,150 megawatts of technically recoverable electrical power capacity potential across several municipal districts in western Alberta.

Alberta has a number of advantages to develop geothermal energy, including:

- a natural geological advantage the opportunity to repurpose inactive oil and gas wells, well sites and infrastructure;
- leadership in drilling technology extensive oil and gas expertise; and
- a well-established service sector.

The Ministry of Environment and Parks regulates shallow geothermal development, which is above the base of groundwater protection – that is, the depth at which groundwater is estimated to transition from non-saline to saline. Companies, investors and municipalities have expressed interest in exploring deep geothermal development, which occurs below this level, where the true potential lies. Currently, Alberta assesses geothermal resources below the base of groundwater protection project applications on a case-by-case basis as no policy or legislative framework currently exists to regulate geothermal development. Given the increased interest in geothermal development, establishing a dedicated geothermal framework will enhance efficiency and clarity for investment.

The Ministry of Energy is leading efforts in advancing a geothermal policy and regulatory framework that aims to enable and support the development of this emerging resource. Developing and implementing geothermal specific legislation and regulation, will provide industry with clarity on rules and processes, establish an approach to land use and liability management, and protect landowners and mineral rights owners.

In July 2020, the government initiated work to better enable geothermal development in Alberta, the *Geothermal Resource Development Act*. The Act accomplishes the following:

- defines geothermal resources and ensures the right to access and use this resource rests with the owners of the mineral title from which the resource is extracted;

- establishes the Alberta Energy Regulator as the single lifecycle regulator for deep geothermal resource development; and
- enables regulation making powers with respect to tenure, royalty, surface access, and liability management.

The Ministry of Energy engaged with stakeholders in October 2020 to provide awareness on the content of the new legislation and to guide implementation and regulation development. Stakeholders include representatives of geothermal industry, investment community, environmental organization, surface rights organization and academic and municipality stakeholders. Stakeholders were generally supportive of the geothermal legislation and geothermal development in general, but sought clarity on how regulations would be operationalized. Government committed to communicating and working with stakeholders throughout implementation of the legislation as it unfolded. Invitations were also sent out to Indigenous communities and offered opportunities to set up one-on-one engagement as part of the government's commitment to ensure Indigenous peoples are partners in long-term prosperity, including opportunities to participate in this new sector.

The *Geothermal Resource Development Act* establishes the legislative foundation to enable a geothermal regulatory regime and enable further development of a geothermal policy and regulatory framework. Modelled after the *Oil and Gas Conservation Act,* the legislation provides the Alberta Energy Regulator with the authority to regulate the safe, efficient, and responsible development of Alberta's geothermal resources. The legislation also clarifies that the right to access and use geothermal resources rests with the owners of the mineral title from which the resource is extracted. It also clarifies industry requirements, establishes the AER's oversight authority, and establishes government's ability to receive revenue for geothermal development such as royalties and fees.

As part of implementation, the Ministries of Energy, Environment and Parks, Indigenous Relations, and the Alberta Energy Regulator established working groups to focus on developing regulatory provisions to implement the new Act. Effective and responsive collaboration of the cross-functional and cross-ministry teams continues throughout spring and summer 2021 in support of drafting regulations and rules. The Act is targeted to come into effect in Fall 2021.

Helium

Developing untapped resources – such as helium – further diversifies Alberta's energy sector, as the province is well-positioned to meet increasing global demand. Close proximity to the U.S. – the world's largest helium consumer – is one of the reasons for a surge of interest from investors to develop the resource, along with its growing use in medical imaging, electronics, and space exploration. Canada has the fifth largest helium reserves in the world.

As Alberta had no existing helium royalty rate, establishing a stable and competitive royalty regime would allow interested stakeholders clarity on the framework they would be operating under. In April 2020, Alberta established a net royalty rate of 4.25 per cent of the revenue calculation at the wellhead for helium production in the province. The royalty rate includes a Helium Royalty Adjustment Factor, which will be reviewed after five years. The Crown is allowed to collect royalties on helium production and specify a royalty rate through amendments to the Natural Gas Royalty Regulation, 2009 and Natural Gas Royalty Regulation, 2017. The policy set clear royalty rules for potential operators, and provided a competitive rate that does not hinder project economics. It will encourage exploration activity in southern Alberta and will create direct employment , which does not include drilling and completion.

Instead of creating new tenure and royalty regimes for helium production in Alberta, the department decided to take advantage of the fact that helium is included in the *Mines and Minerals Act* as an off stream component of natural gas. Operators must use existing and well understood natural gas tenure rules to acquire tenure and pay royalties per the existing provisions in the Natural Gas Royalty Regulations.

Since 2016, the City of Medicine Hat and several stakeholders expressed interest in evaluating and developing helium resources in southeast Alberta. There is one helium producing company currently operating in Alberta.

The ministry continues to work on identifying the amount of helium production and royalties paid by the one helium producer currently in Alberta. The ministry has been in contact with the producer to better understand their pricing and processing cost methodology in order to assess the accuracy of royalties paid. Once completed, the ministry will be in a position to finalize the total royalties paid for helium produced for the fiscal year.

Methane Emissions

In November 2015, Alberta announced an oil and gas methane reduction target of 45 per cent by 2025 from 2014 levels. Shortly thereafter, the Government of Canada announced a similar target of 40 to 45 per cent by 2025 from 2012 levels. Methane regulations involve complex projections, so extensive analysis and technical discussions were required to understand how to best resolve the differing approaches to the federal and provincial models. Since discussions with the federal government began in 2017, both models have been updated to incorporate new and more accurate data published in widely recognized studies.

Did you know...

Alberta was the first regional government in North America to commit to a methane emissions reduction target for the oil and gas sector. In Alberta, energy production is the largest source of methane emissions with approximately three-quarters of provincial methane emissions coming from the upstream oil and gas sector.

As the climate change impact of methane is 25 times greater than carbon dioxide over a 100-year period, cutting methane emissions is a cost-effective way to reduce greenhouse gas emissions.

Since January 2020, both federal and provincial methane regulations applied in Alberta, increasing red tape and imposing additional costs onto Alberta's energy sector. In November 2020, Alberta successfully reached an equivalency agreement with the federal methane regulation ensuring that the province remains in charge of regulating its natural resources while providing the flexibility and innovation for industry to reduce their emissions in a cost-effective manner, targeting actions where they are needed. Alberta worked with conventional oil and gas stakeholders to develop a methane emissions reduction policy that will save industry about $600 million between 2020 and 2024 while achieving the same environmental outcomes as the federal government's proposed methane policies.

Alberta's methane regulations are made up of:

- Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting; and
- Directive 017: Measurement Requirements for Oil and Gas Operators and Alberta's Methane Emission Reduction Regulation.

The provincial and federal methane models are different – using different methodologies, assumptions, and data inputs. Alberta modeling results show the provincial regulation achieves equivalent environmental outcomes to the federal regulations at less cost to industry, while providing more flexibility for producers to tailor efforts to their specific facilities and operations. Alberta's Methane Emission Reduction Regulation focuses on higher standards for new facilities. It also provides more flexibility for existing operations, facilitating innovative solutions. It is more cost-effective to integrate environmental solutions at the facility construction phase than to retrofit the existing infrastructure.

Since the start of 2020, more than $265 million have been made available for methane reduction projects in Alberta. This includes $52 million from the Technology Innovation and Emissions Reduction system to support methane programs that will create jobs in the oil and gas sector and cut about 1.5 megatonnes of emissions right away, while also setting the stage for future job growth and reduced emissions after projects are complete. Alberta's approach has been used to highlight best practices for methane reduction on the world stage. For example, Alberta's flaring standards were adopted as a model by the World Bank's Global Gas Flaring Reduction Partnership, a program aiming to integrate best practices in the development of flaring regulations.

Did you know…

Canadian oil sands breakeven costs rank near the median when compared with global oil producing regions and can be as competitive as US tight oil based on data from IHS Markit and Wood Mackenzie. When comparing oil sands projects globally, Canadian competitiveness has improved over the past 10 years.

The Alberta Energy Regulator reports that a typical new in-situ project's break-even cost has fallen from a range of US$55-US$85 per barrel in 2013 to a range of US$40-US$50 per barrel West Texas Intermediate equivalent in 2019.

Mineral Rights Compensation Regulation (MRCR)

The MRCR was amended effective May 13, 2020, following administrative review by the Ministry of Energy. The regulation supports the Ministry of Energy's responsible resource development mandate by establishing a fair compensation process that is consistent, predictable, and fair for both the Crown and Crown mineral rights holders.

The MRCR plays an important role in mitigating the effects of Crown mineral rights cancellations on the province's investment attractiveness while limiting the financial liabilities facing the Crown when changes in land management need to be pursued for public interest reasons, or agreements need to be amended to correct zone misdescriptions. The amendments improve clarity for users and will result in faster processing times. They also ensure the regulation is working as intended – that compensation is set at a level that balances the interests of both industry and Albertans, and that compensation can be obtained with minimal transaction costs. All of these are outcomes that are aligned with the Red Tape Reduction goal of reducing regulatory burden while upholding fiscal accountability.

Clean Fuel Standards (CFS)

The Ministry of Energy supported the Ministry of Environment and Parks in engaging with the federal government on the draft Clean Fuel Standard Regulations, established as part of Canada's goal to exceed the current greenhouse gas emission reduction target under the Paris Agreement. The proposed regulatory approach is for liquid fossil fuel types, including gasoline, diesel, kerosene and light and heavy oils. The Ministry of Energy has supported the Ministry of Environment and Parks in conveying larger concerns over potential impacts of the CFS to vulnerable households and trade-exposed sectors and issues regarding compliance flexibility, potential for carbon leakage, and additional investment uncertainty. As CFS is a federal initiative, Alberta continues to focus on encouraging an outcome that produces efficient policies that encourage investment and avoid additional unintended consequences for Alberta's energy sector.

Did you know…

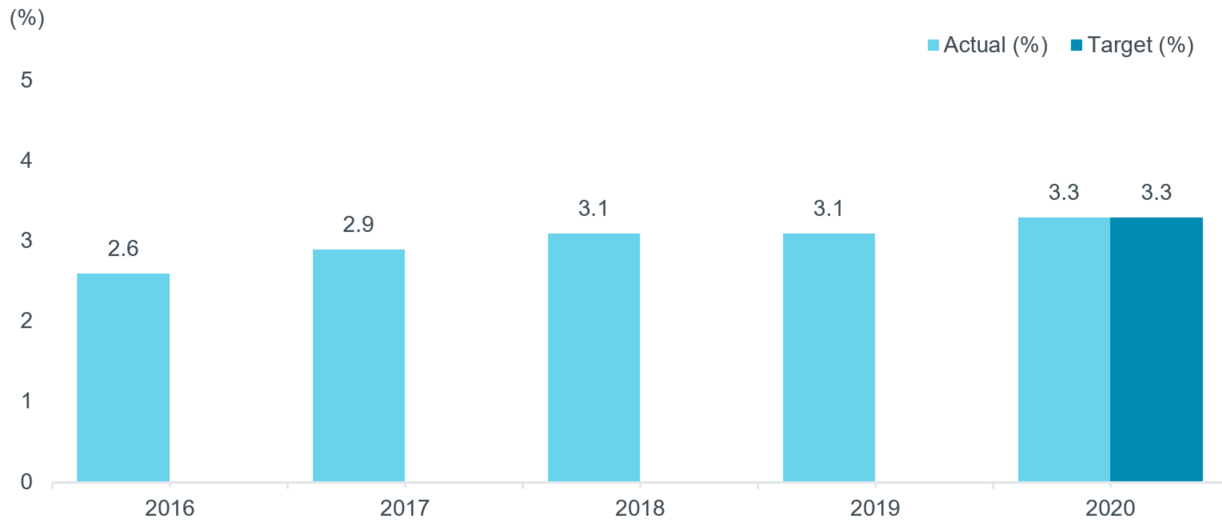
In January 2020, Alberta Innovates launched an international $15 million Carbon Fibre Grand Challenge as part of its broader Bitumen Beyond Combustion initiative to further the development of non-combustion products and their production technologies, derived from bitumen contained in oil sands.

If the market reaches its potential, the value of every barrel in the ground in Alberta would increase by five to 10 times — and a new industry could take root that might one day generate between $50 billion and $100 billion in annual revenue. Alberta Innovates estimates the added economic potential of carbon fibre, activated carbon and asphalt binder alone could be in the range of $84 billion annually.

Carbon fibre is 10-times stronger than steel, and composite materials that use it are being tested in a wide range of potential applications, from automobiles and the aerospace industry to concrete, plastics, and wood products. Currently, the global carbon fibre industry is growing at a compound annual growth rate of more than 10 per cent.

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

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



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

Discussion of Results

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

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

The 2020 supply share met its target of 3.3 per cent. The rate of global year-over-year consumption decreased by 8.7 per cent from 99.7 million barrels per day (bbl/d) in 2019 to 91.0 million bbl/d in 2020, due to the impacts of COVID-19 outbreak on the global economy. The growth rate of Alberta's total crude bitumen production from 2019 to 2020 declined by four per cent. However, the rate of production decline in Alberta was not as significant as the rate of global production decline from 2019 to 2020 as the Organization of the Petroleum Exporting Countries Plus decided to balance the global crude oil market and curtail production by more than the fall in global demand.

Total crude bitumen production in Alberta declined from 2019 to 2020, from about 3.10 million bbl/d to about 2.98 million bbl/d. Both mined and in-situ production declined by about 4 per cent. Mined production declined from 1.55 million bbl/d in 2019 to 1.48 million bbl/d in 2020, and in-situ production declined from 1.55 million bbl/d in 2019 to 1.49 million bbl/d in 2020. Both mined and in-situ production accounted for about 50 per cent of total bitumen production in the province in 2020, with in-situ production accounting for a marginally larger share of production.

The decline in crude bitumen production in Alberta was due to the impacts of COVID-19 pandemic, which significantly affected crude oil demand in Alberta's traditional market, the United States.

[i] For more information, see the Performance Measure and Indicator Methodology section on page 87.

Outcome Two

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

What it means:

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

Key objectives to support the achievement of this outcome include:

2.1 Collaborate with other ministries to establish a balanced and sustainable approach to manage the cumulative effects of resource development, including liability management and regional planning

2.2 Optimize regulation and oversight:

- through the Alberta Energy Regulator to ensure the efficient, effective, and environmentally responsible development of Alberta's energy resources, and
- of Alberta's utilities, through the Alberta Utilities Commission, to ensure social, economic and environmental interests of Alberta are protected.

Key Objective 2.1

Collaborate with other ministries to establish a balanced and sustainable approach to manage the cumulative effects of resource development, including liability management and regional planning.

Integrated Resource Management

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

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

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

The ministry supports informed decision making by leading the Engaging Communities Practice Group, collaborating with other ministries through IRMS, and conducting engagement sessions with Indigenous communities, industry participants and other stakeholders. In 2020-21, the Ministry of Energy worked collaboratively with cross-ministry partners and external stakeholders at all levels to advance the department's responsible resource development and stewardship objectives.

The examples below are a few of the highlights:

- Conserved Land: In 2020-21, the Ministry of Energy supported the Ministry of Environment and Parks' efforts to analyze the proposal to expand the Kitaskino Nuwenëné Wildland Park, located south of Wood Buffalo National Park, most notably completion of socio-economic analysis. The proposal, which was made possible by the collaboration of Indigenous communities, industry partners, and the Government of Alberta, was announced for public consultation in February 2021. Consultation closed March 15, 2021. If approved, the expansion will add 143,800 to the largest continuous area of protected boreal forest in the world.
- Caribou Sub-Regional Task Forces: Three caribou sub-regional task forces were created in November 2019, with a mandate to provide recommendations on land-use planning at the local scale, including caribou recovery actions. Recommendations from the task forces will guide the development of sub-regional plans. Over the last year, the task forces delivered recommendations for the Cold Lake, Bistcho and Upper Smoky sub-regions. The Ministry of Energy supported the planning led by the Ministry of Environment and Parks by representing the department's responsible development mandate and providing information about Alberta's Crown mineral resource management systems and industry activities. The Cold Lake and Bistcho Lake sub-regional plans are expected to be completed in 2021, while the plan for Upper Smoky is expected to be completed in 2022, as established in the Alberta-Canada Section 11 Conservation Agreement for Boreal Caribou under the *Species at Risk Act*.
- Moose Lake 10 KM Special Management Zone Plan: Led by the Ministry of Environment and Parks, the Moose Lake Access Management Plan was adopted by the Government of Alberta in February 2021, following extensive collaboration across ministries, and engagement with industry stakeholders and Indigenous communities. The plan provides new direction for natural resource development and land management in the Moose Lake area of the Lower Athabasca Region. The plan allows oil sands development to continue in a way that better supports the exercise of Treaty rights and traditional land uses, as well as overall ecological integrity.

Coal Policy Rescission and Reinstatement

The Government of Alberta rescinded the 1976 A Coal Development Policy effective June 1, 2020. The policy was reinstated on February 8, 2021 in response to concerns raised by Albertans. Additionally, the Minister of Energy issued a directive to the Alberta Energy Regulator indicating that:

- no mountaintop removal will be permitted in Category 2 and all of the restrictions under the 1976 coal categories are to apply, including all restrictions on surface mining in Category 2 lands; and
- no new coal exploration approvals on Category 2 lands will be allowed, pending vigorous and widespread consultation on a modern coal policy.

On January 20, 2021, the Minister of Energy directed the ministry to cancel the 11 coal leases issued from a December 15, 2020 coal public offering. The estimated cost of cancelling these leases is $80,000. The exact cost will not be known until affected companies submit their claims under the Mineral Rights Compensation Regulation, and the Ministry of Energy adjudicates those claims. Notice of intent to cancel was issued to the impacted lessees on March 26, 2021. The issuing of compensation and the cancellation of the leases is expected to occur in 2021. The 154 coal leases issued from coal lease applications being held in the application stage in Category 2 and 3 lands under the coal policy remain in effect.

Alberta produces two types of coal.

- Subbituminous coal is a low rank of coal that is used domestically to produce electricity. It does not derive sufficient value to make it economic to export.
- Bituminous coal is a higher rank of coal that is exported overseas for electricity production (thermal coal) or to make steel from iron ore (metallurgical coal)

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

Albertans have spoken clearly and government has heard them. When the policy was rescinded, it was not the intent to remove any restrictions or protections related to coal development. The Government of Alberta saw a policy that had been made obsolete through more modern oversight, but did not anticipate the unintended consequences of removing the coal categories. The intent was to align the disposition of coal rights with all other commodities, but Albertans made it clear that they expect coal to be managed differently.

Public engagement on Alberta's approach to coal development began on March 29, 2021. This engagement is being led by an independent Coal Policy Committee, which has been tasked with developing and leading the engagement process and delivering a final report to the Minister of Energy by November 15, 2021. Concurrently, the Ministry of Energy, with support from the Ministry of Indigenous Relations, is engaging directly with First Nations and Metis communities to ensure Indigenous perspectives on coal development are heard and considered in the development of a new coal policy.

Liability Management Framework

Along with the Ministry of Environment and Parks, industry and Albertans, the Ministry of Energy continued to address the liability management challenges facing energy development. These liability challenges include company insolvencies, unpaid surface rentals to landowners, unpaid municipal taxes, and a growing inventory of orphan and inactive wells – exacerbated in recent years by low commodity prices, the continued world health pandemic, collapse in energy prices and the resulting economic downturn. Many energy jurisdictions are facing similar challenges.

A new framework to manage oil and gas liabilities was announced July 30, 2020, which includes a series of mechanisms and requirements to improve and expedite reclamation efforts. The new framework enables industry to better-manage the clean up of oil and gas wells, pipelines and facilities at every step of development, from exploration and licensing, through operations, mergers and acquisitions, abandonment, reclamation, and post-closure.

Government worked with the Alberta Energy Regulator to fully implement the new framework in a phased approach that helps industry transition to new requirements and supports refinements to programs and regulatory tools based on early learnings. Setting clear expectations throughout the life cycle of oil and gas projects will provide certainty to industry and landowners, who will now have a defined opportunity to ensure the timely clean-up of sites on their property. The new framework does the following:

- Upholds the polluter-pays principle, ensuring that industry is responsible for clean up costs, in a way that is fair and manageable.
- Provides practical guidance and proactive support for struggling operators, helping them to manage and maximize their assets, and maintain their operations. Doing so protects Albertans from the financial and environmental burden of more inactive or orphaned sites – while ensuring operators meet their environmental responsibilities.
- Puts an improved system in place to assess the capabilities of oil and gas operators to meet their regulatory liabilities obligations, prior to receiving regulatory approvals, and enable the regulator to reach out proactively to provide support before operators are struggling.
- Establishes five-year rolling spending targets for reclamation that every active site operator must meet. This initiative includes the AER's area-based closure program, through which companies work together to share the cost of cleaning up multiple sites in an area.
- Establishes a formal opt-in mechanism for landowners to nominate sites for clean up. These sites must then be reviewed by the regulator, with operators responsible for justifying why a site should not be immediately brought through closure stages.
- Implements a process to address legacy and post-closure sites – or sites that were abandoned, remediated or reclaimed before current standards were put in place, and sites that have received reclamation certificates and the operator's liability period has lapsed. A panel of experts will provide advice on how to address this gap, bringing these sites up-to-date with the current environmental requirements.
- The framework includes the expanded role of the Orphan Well Association and enhanced management of orphaned sites enabled by the *Liabilities Management Statutes Amendment Act* – which came into effect June 15, 2020 – enabling the association to better manage and accelerate the clean-up of wells, infrastructure and pipelines that do not have a responsible owner.

Alberta's former approach to governing the clean up of these wells was put in place decades ago, when the oil and gas industry was developing and largely focused on growing production and building core infrastructure. As the province's oil and gas sector has matured, the new framework is required to more actively manage reclamation of sites throughout their life cycle. This means working on existing sites that require clean up and preventing new sites from joining the inactive and orphan inventories in the future.

The actions being taken under this new framework will create jobs by accelerating clean up of inactive and orphaned wells across the province, protect landowners and communities by ensuring more timely restoration of land to its original state, and protect future generations from experiencing a backlog of sites needing clean-up and from paying these costs. As a result government is ensuring wells are cleaned up faster, reinforcing Alberta's reputation as a leader in responsible energy production.

Clarifying the rules and improving the available support, provides industry with the certainty needed to make long-term investment decisions and help the province's recovery efforts. Setting clear expectations throughout the life cycle of oil and gas projects provides certainty to landowners, who now have a defined opportunity to ensure the timely clean-up of sites on their property. The government is spurring activity in the oil field services sector, creating good paying jobs and putting thousands of Albertans back to work.

Orphan Wells

In 2020-21, the management of orphan sites was enhanced through Bill 12, the *Liabilities Management Statutes Amendment Act*, as one part of Alberta's new liability management framework, ensuring a responsible, sustainable oil and gas industry in our province for generations to come. The amendments added authorities for the AER to compel operators to take reasonable care and measures to prevent damage or impairment on oil and gas sites and expanded the mandate of the OWA and enable the association to effectively manage and accelerate the cleanup of orphan sites, helping the AER and OWA protect the value of producing assets and mitigate the risk of an expanding volume of orphan sites. With this enhanced authority and expanded scope the AER has greater ability to take steps to prevent sites from becoming orphaned in the first place, and the OWA has more delegated authority to protect the value of producing assets, protect jobs, protect public safety, and mitigate the risk of a growing inventory of orphan sites.

What is the Orphan Well Association?

The Orphan Well Association is an independent, non-profit organization that operates under the delegated legal authority of the Alberta Energy Regulator through the Orphan Fund Delegated Administration Regulation.

The OWA's mandate is to manage the abandonment and closure of orphan sites – sites that do not have a solvent and responsible owner – to protect people and the environment, and remove the potential risk of unfunded liability.

The orphan fund levy is collected from industry players based on licensees' percentage of liability out of the total industry liability.

The OWA is led by an independent Board of Directors which includes industry, regulatory, and government representatives.

On March 2, 2020, an additional interest-free $100 million loan to the Orphan Well Association was announced, which is was expected to create up to 500 direct and indirect jobs in the oil services sector, and allow for approximately 1,000 more wells to be decommissioned and 1,000 additional site assessments for reclamation. As of March 31, 2021, the Orphan Well Loan Program has spent approximately $284 million of the total $335 million, generated approximately 269 direct jobs, and reported the following results from its effort to address the growing inventory of orphaned sites:

- a total of 3,235 wells abandoned;
- 3,667 pipelines decommissioned; and
- 1,608 sites reclaimed.

The money received from industry through the annual Orphan Fund Levy is used by the OWA to repay the loan. As of April 2021, the OWA has repaid $61.4 million.

Area-Based Closure (ABC)

The area-based closure program encourages companies to work together in project areas to close oil and gas infrastructure and sites more efficiently and effectively. Through the voluntary program, participants may commit to a closure spend target in exchange for program incentives. More closure work can be completed with the same closure budget using the ABC program principles to help reduce liabilities associated with inactive sites.

In 2020, ABC participants conducted approximately 61 per cent of all abandonment and reclamation in Alberta – spending more than $295 million in the process. Due to the exceptional circumstances from the COVID-19 pandemic and its consequential impact on the oil and gas industry in 2020, government suspended the requirement for licensees to meet their ABC inactive liability reduction target. However, licensees were still encouraged to conduct closure work and report their related activity and expenditures as this information impacts future closure target assessments.

For comparison, in 2019, 56 ABC participants conducted almost 70 per cent of all abandonment and reclamation in Alberta – spending more than $340 million in the process. Of program participants surveyed, 81 per cent indicated that the program helped them move infrastructure through the closure process more efficiently, 33 per cent collaborated on closure with another company, and 14 per cent collaborated with the Orphan Well Association. This focus on collaboration and the resulting cost and operational efficiencies is expected to increase the number of oil and gas sites that a company can abandon, remediate, and reclaim with their closure budget. For more information, see the ABC Program 2019 Highlights report at www.aer.ca.

Companies reported that the most valuable part of ABC was having a predictable closure budget through the commitment to a closure spend target. This enables long-term planning for complex closure projects over multiple years. It also reduces the risk of closure budgets being cut mid-project, which often results in additional closure costs.

Well Status Definitions

- Orphan: A well or facility confirmed not to have anyone responsible or able to deal with its closure and reclamation.
- Inactive: A well or associated facility where activities have stopped due to technical or economic reasons. Not all sites in this category are orphaned. Many may be reopened and produce again at a later date.
- Abandoned: A site that is permanently dismantled (plugged, cut and capped) and left in a safe and secure condition.
- Remediation: The process of cleaning up a contaminated well site to meet specific soil and groundwater standards.
- Reclamation: The process of replacing soil and re-establishing vegetation on a wellsite so it can support activities similar to those it could have supported before it was disturbed.
- Post-closure: Sites that have met reclamation requirements and the operator is no longer legally responsible, but future issues may have arisen.

Annual Wells Decommissioned: Performance Indicator 2.e

Decommissioning is part of the closure process and involves the company removing surface equipment and sealing the well to prevent the well from impacting the environment. This indicator demonstrates the degree to which industry is moving inactive well inventory through the lifecycle towards closure. Recent increases in insolvent companies and low commodity prices have resulted in an unprecedented number of wells and facilities being sent to the Orphan Well Association (OWA).

	2016	2017	2018	2019	2020
Number of wells decommissioned and left in a safe and secure condition	3518	5392	5301	5994	6503
Per cent of wells decommissioned and left in a safe and secure condition compared to inactive well population	3.8	5.7	5.6	6.0	6.3

Source: Alberta Energy Regulator[i]

[i] For more information, see the Performance Measure and Indicator Methodology section on page 87.

The number of wells decommissioned rose by 509 from the previous year's result of 5,994 for a result of 6,503 in 2020. During 2020, the annual wells decommissioned in the province increased to 6.3 per cent from the previous year's result of 6.0 per cent. An increase in year-over-year numbers is a positive signal that operators are addressing their inactive well inventory, which prevents the well from impacting the surrounding environment. The increase of annual wells decommissioned in 2020 can be attributed to a number of factors including the stimulus provided by the Site Rehabilitation Program and the OWA's Orphan Well Loan Program.

While well decommissioning work has accelerated, so too has the growth in Alberta's cumulative inactive well population, which was 96,394 in 2020, up from 94,330 in 2019.

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

Factors that may lead to an increase in the inactive well population include continued low commodity prices and an increasing number of insolvent companies. The COVID-19 pandemic caused a sudden drop in demand for oil in early 2020, further reducing economic viability of operational activity. Alberta continues to experience an increase in insolvent companies, resulting in an unprecedented number of wells and facilities being sent to the OWA.

Government is addressing these challenges through the aforementioned changes to the Liability Management Framework, Orphan Well Association loan and the AER's Area-Based Closure Program.

Key Objective 2.2

Optimize regulation and oversight:

- **through the Alberta Energy Regulator to ensure the efficient, effective, and environmentally responsible development of Alberta's energy resources, and**
- **of Alberta's utilities, through the Alberta Utilities Commission, to ensure social, economic and environmental interests of Alberta are protected.**

Alberta Energy Regulator (AER)

The AER is responsible for regulating the life cycle of oil, oil sands, natural gas and coal projects in a manner that protects public safety and the environment.

In 2020-21, the AER's operating costs totalled $204 million. AER energy regulation activities are fully funded by industry.

Regulatory Optimization and Red Tape Reduction at the AER

The AER is looking at its full suite of regulatory instruments to identify where it can remove duplication in requirements, increase process efficiency, save industry money, and modernize regulations to be current with today's technological innovations. The AER is also making modifications to regulatory instruments as part of its contribution toward the Government of Alberta's *Red Tape Reduction Act*. Overall, these enhancements will help ensure regulatory instruments are necessary, effective, efficient, and proportional. This approach will also help the AER reduce overlap in how it manages energy development, improve how the AER responds to government policy changes, and how it accommodates new technologies while maintaining its commitment to public safety and environmental protection.

Significant regulatory changes were implemented in 2020-21, including the amendment of 35 regulatory instruments and nine regulatory projects. The AER has an environmental and public safety mandate that must be upheld, which requires the AER to carry out stakeholder and public engagement on any changes that are significant and impact industry, which can tend to cause projects to have longer timelines. The following are some of the significant results achieved:

- Updated Directive 020, which focusses on well abandonment and commingled abandonment, to allow for routine commingled abandonment of AER pre-approved oil and gas pools, eliminating the need for industry to submit well license-based variance requests to the AER for approval.
- Modernized Directive 054, which focusses on performance presentations, auditing, and surveillance of in situ oil sands schemes, to significantly reduce requirements associated with plotting and reporting reservoir temperature and pressure data; this change has resulted in more consistent submissions across operating sites through removal of a number of redundant and/or extraneous reporting requests.
- Updated Directive 060, which focusses on upstream petroleum industry flaring, incinerating, and venting, to allow the deployment of combustors/incinerators between 100 and 500 meters of a residence to enable an operator to incinerate/combust but not flare uneconomic solution gas between 100 and 500 meters of a residence.
- Published Manual 020, the Alberta Coal Development Manual, to provide clear relevant reference materials for industry and make the application review process more efficient, helping to reduce the number of incomplete applications.

Indigenous Engagement at the AER

Over the past five years, the AER has initiated a journey to improve engagement with Indigenous communities and consider their values, interests, and concerns. The AER strives to achieve a future-state where AER's relationship with Indigenous peoples is one of mutual respect and trust. An incremental approach grounded in learning is leading the AER towards this goal. A foundation of this approach is the book Voices of Understanding, which was co-created in 2017 with an Indigenous elder and AER staff and is available on the AER website at www.aer.ca. The book is a guide to the AER regarding indigenous worldviews and how to initiate and engage using respectful decision-making processes.

This work is intended to support informed understanding, demonstrate AER's environmentally responsible approach to energy development, and assist with positive social outcomes for indigenous peoples with respect to energy development.

In the past year the AER has delivered on the following:

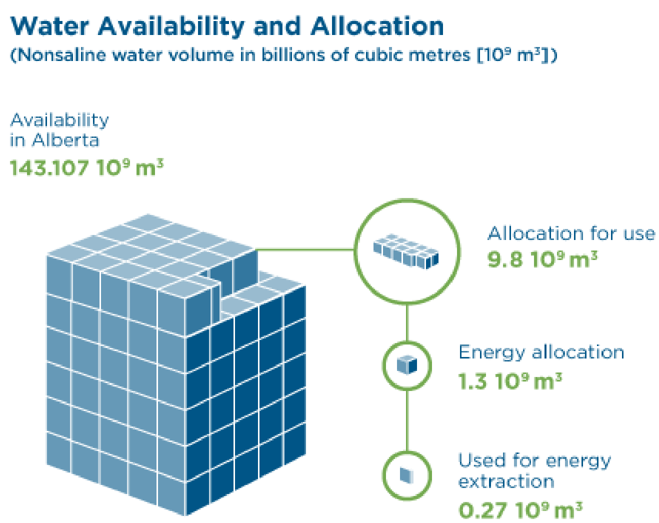
- Developing and delivering indigenous awareness training content for AER staff.
- Creating opportunities for First Nations and Metis Settlements to participate in joint compliance inspections on their lands.
- Engaging senior leadership in building relationships with Indigenous organizations.

This work has built skills and competencies that support the AER in meeting its mandate of ensuring safe and environmentally responsible development of energy resources over the entire life cycle.

AER Industry Performance Program

The industry performance program is an important way that the AER measures, evaluates, and reports on key energy development activities that they regulate. The program provides reports in three areas: pipeline, methane, and water use performance. The purpose of the program is to enhance transparency for Albertans; help companies improve their performance; and to assess the effectiveness of AER's regulatory tools and requirements. Industry performance reporting supports organizations that evaluate Environmental, Social and Governance.

- Pipeline Performance-The latest pipeline performance report shows that over the past 10 years, the number of pipeline incidents dropped by 32 per cent despite the total length of pipelines growing by 13 per cent. The number of incidents decreased by six per cent in 2019 compared to 2018. High consequence pipeline incidents decreased 17 per cent in 2019 compared to 2018. The full report can be viewed at www.aer.ca.
- Methane Performance-In 2020, the AER launched a methane performance report, which shows that gas flaring and venting have been decreasing over the last five years, with total gas vented reaching an all-time low. Better industry understanding of, and compliance with, requirements will be critical to successfully reducing methane emissions. Overall venting has been decreasing since 2014. The vent gas volumes reported in 2020 (325.8 million cubic meters) are greater than those reported in 2019 (174.8 million cubic meters); however, this is not an increase in venting, but a shift in volume from one reporting category to another. The definition for vent gas was revised as part of the methane reduction requirements. Starting in 2020, volumes that would have previously been reported as fuel gas are now being reported as vent gas. Fuel gas volumes for 2019 (25.4 billion cubic meters) and 2020 (24.3 billion cubic meters). View the full report at www.aer.ca.
- Water Use Performance-The AER reports company-specific information on the amount of water used for in-situ, mining, hydraulic fracturing and enhanced oil recovery operations annually, and provides contextual information concerning the major drivers of water use during energy extraction within each of these sectors since 2017. The water use report provides water availability, water allocation and water use by the oil and gas industry in a transparent and accessible way for the public, stakeholders and industry. The report aims to influence industry behavior and innovation for water use without additional regulation. The water use report has also allowed the AER to address media enquiries and to provide factual information to both the AER and Government of Alberta to counter incorrect information in media reports. In 2020-21, the AER released its water use report for 2019 data on the AER website at www.aer.ca. The context the report provides helps alleviate concerns by demonstrating that water is adequately regulated, and there is enough water available compared to the amounts allocated and used. For example, in 2019 the energy industry only used about 20 per cent (just over 266 million cubic metres) of what was allocated to them, or 0.19 per cent of all nonsaline water available in Alberta. Using alternatives to nonsaline water and making improvements in technology reduces how much nonsaline water is needed for energy development. In fact, 81 per cent of



water used to recover energy resources in 2019 was recycled, and only 18 per cent of the water needed for energy development was nonsaline.

Regulatory Enforcement and Compliance Inspections: Performance Indicator 2.c

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

The trend of inspections not resulting in enforcement has been consistently over 99 per cent for the past five years. This year's result of 99.7 per cent increased by 0.1 per cent from last year's result of 99.6 per cent. The per cent of inspections in compliance with regulatory requirements has been increasing over the last five years. In 2020-21, the per cent of inspections with a compliant inspection result was at a five-year high, at 79 per cent.

	2016-17	2017-18	2018-19	2019-20	2020-21
Regulatory Enforcement: Per cent of inspections that did not result in enforcement actions	99.6	99.7	99.8	99.6	99.7
Compliant Inspections: Per cent of inspections in compliance with regulatory requirements	76	76	76	78	79

Source: Alberta Energy Regulator[i]

In 2020-21, the AER conducted 9,048 field-based inspections, of which 7,175 resulted in a finding of compliance; meanwhile, in 2019-20, 9,625 field-based inspections were conducted, of which 7,451 resulted in a finding of compliance. The inspections resulted in the issuance of 16 compliance and enforcement actions, including 5 administrative penalties, 2 prosecutions and 9 warning letters.

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

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

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

[i] For more information, see the Performance Measure and Indicator Methodology section on page 87.

Pipeline Safety: Performance Indicator 2.d

The mandate of the AER is to ensure the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources over their entire life cycle. AER-regulated pipelines transport most of the natural gas, crude bitumen and crude oil produced in Alberta to processing facilities and eventually to market. The AER uses pipeline incidents as an indicator because of the impacts incidents can have to the environment, wildlife and the public.

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

Companies must have a safety and loss management system (SLMS) that provides for the protection of people, the environment, and property. An SLMS includes risk management, pipeline integrity management, and operations and maintenance. The integrity management programs and operations and maintenance procedures outline the specific activities, inspections, and controls used to maintain the pipeline. Companies use risk management to identify hazards to their pipeline systems and address them. The AER conducts construction and operational inspections, to ensure operators are in compliance with pipeline regulations to safely operate and prevent incidents. AER inspections focus preventative pipeline maintenance programs, leak detection, pipelines that cross water courses, unstable slopes and inactive pipelines to prevent pipeline incidents from occurring. When a pipeline incident does occur, all incidents are reviewed by an inspector to understand the cause and prevent future incidents of a similar manner.

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

	2016	2017	2018	2019	2020
Number of high-consequence pipeline incidents	29	26	24	20	16

Source: Alberta Energy Regulator[i]

Note: Changes to previously reported numbers and are subject to change as more information is gathered over time and reviews are conducted.

Compared with 2019, 2020 saw a decrease of high consequence pipeline incidents from 20 to 16 and a decrease in overall pipeline incidents from 392 to 344. Some factors that influenced these results in 2020 include the following:

- The AER continues to educate licensees on integrity management programs.
- The total volume of liquid releases increased from 5,576.94m3 in 2019, to 9271.91m3 in 2020 and was largely attributed to one incident which released 5000m3. The AER continues to educate and ensure compliance regarding leak detection programs to prevent large volume spills.
- The decrease in total incident number can likely be attributed to lower activity in the oil and gas sector.
- In 2019, Bulletin 2019-28 was issued to bring awareness to the industry of incidents resulting from earth movement of unstable slopes (8 incidents total). In 2020, the number of incidents decreased to 3.

i For more information, see the Performance Measure and Indicator Methodology section on page 87.

Fluid Tailings Management

In 2020-21, the AER released the 2019 State of Fluid Tailings Management for Mineable Oil Sands report. The report provides Albertans with information on regional and individual operator fluid tailings volumes relative to fluid tailings profiles and other information related to fluid tailings management for oil sands mining operations. Alberta has eight operating oil sands mines, and by the end of 2019, each site had an approved tailings management plan. Under Directive 085, Fluid Tailings Management for Oil Sands Mining Projects, mine operators must annually submit tailings management reports that show how they are implementing their tailings management plans. This report summarizes the information for the 2019 reporting year and assesses the operators' progress in managing fluid tailings. Operators continue to report improvements in their current tailings treatment technologies and the piloting and development of new technologies.

The Fluid Tailings Management report has allowed the AER to address media enquiries and to provide factual information to counter incorrect information in media reports and to make decisions. The full report can be accessed at www.aer.ca.

Dam Safety

Dams are owned by operators in oil sands mining, in-situ oil sands, coal mining, and oil & gas operations. Under the Water Ministerial Regulation (WMR) and its associated Dam and Canal Safety Directive, the AER regulates dams operated by energy companies. Together, the WMR and Directive states all requirements owners need to put in place to safely design, construct, operate, manage, and decommission their dams. Regulatory requirements are based on the consequence-of-failure classification of the dam. As of 2021, the AER regulates a total of 215 dams, including 121 tailings dams, the majority of which are in the oil sands mining sector. Owners are responsible for the safety of their dams and compliance with regulatory requirements. The AER Dam Safety program ensures that dam owners are operating their dams in accordance with regulatory requirements, government policy, and industry best practices to protect the public and the environment from dam-related incidents. The AER Dam Safety Map provides to the public information on AER regulated dams and is available at www.aer.ca.

In 2020, the AER conducted a virtual industry session to clarify regulatory expectations for dam operators. The AER also successfully completed all scheduled inspections of dams for 2020. These 81 inspections included high to extreme consequence dams and all mandated inspections of tailings dams. The AER also completed more than 200 technical reviews of dam safety submissions.

Dam safety incidents as defined by the Dam and Canal Safety Directive means an operation or action at, or in connection with, a dam that has the potential to create a hazardous condition or to be or become a hazard to factors at risk. In 2020, no dam safety incidents were identified by or reported to the AER.

In 2020, the Office of the Auditor General assessed the AER's implementation of the 2015 recommendations and found that the AER has implemented all outstanding recommendations.

Alberta Utilities Commission (AUC)

In 2020-21 the AUC worked purposely to improve the efficiency and clarity of its processes and approaches with an overall goal of improving timeliness and predictability, to improve transparency and certainty for investors and stakeholders in the regulatory process, aimed at ultimately supporting the orderly development of Alberta's resources. Alberta's utilities sector is a key enabler of economic activity, investment, employment and well-functioning communities large and small. The sector's health and reasonable rates for consumers are the AUC's highest priorities. The commission's focus is on streamlining regulatory processes and reducing red tape in order to provide more certainty to investors, the electricity market and consumers all while becoming one of the fastest regulators in North America. The agency reports annually on its impact on stakeholders through the AUC Annual Report Card, available on the AUC's website at www.auc.ab.ca.

What is the Alberta Utilities Commission?

The AUC regulates Alberta's utilities sector, natural gas and electricity markets to protect social, economic and environmental interests of Alberta where competitive market forces do not.

The AUC and its predecessor agencies began their work in 1915, applying a suite of evolving government legislation and regulations. As an expert regulator, the AUC is also a resource for government through implementing utilities-related programs, providing research and consultation to support policy development, and in understanding trends and developments in the critical utilities sector.

Generally speaking, the AUC works to ensure that utility facilities are sited and operated in a manner that supports the public interest; and that utility rates are both just and reasonable while providing a reasonable opportunity for utility owners to earn a fair return on their investment.

The cost of the AUC's activities in 2020-21 was $30.5 million and was fully funded by consumers through levies paid by regulated industry. This was a decline of 6 per cent from 2019-20.

Regulatory Enhancement and Modernization at the AUC

In 2020-21, the AUC built upon the efficiency initiatives it identified in its strategic plan in November 2019 and focused on regulatory efficiency through streamlining and eliminating unnecessary regulatory requirements and processes. In part, this was to address policy goals set by government to have the AUC become a leader among North American regulators in terms of the timeliness of its decision making, to respond to the priorities of stakeholders, to accelerate earlier plans, and to address the requirements of the *Red Tape Reduction Act*.

This was done through a multi-pronged approach of AUC's rule review and updating, general streamlining of administrative requirements (in some cases hastened by the logistical requirements of the COVID-19 pandemic) and launching an expert, third-party review of AUC approaches and performance. These included examinations of the benefits of mediated settlements, and a benchmarking of the AUC among its peers, with the goal of delivering turnaround times among the fastest in North America.

Red Tape Reduction at AUC

In June 2019, the AUC implemented the goals of the *Red Tape Reduction Act* and met the goal of a one-third reduction in regulatory requirements by the end of the 2020-21 fiscal year – well ahead of schedule. All of the AUC's strategic planning and implementation activities are executed with red tape reduction in mind. This dovetails with the organization's ongoing efforts to improve regulatory efficiency. This was accomplished through the review of 13 AUC rules centred on setting out requirements or procedures related to rate-setting and applications for and operations of utility facilities. Examples are:

- Rule 017 – revisions simplify Alberta Electric System Operator (AESO) consultation timelines and process, introduce expedited process for minor rule changes saving time for all parties and improving approval times.
- Reducing processing time to cost applications and applications for review and variance of AUC decisions.
- Application streamlining eliminated one proceeding for each of the four electric distribution utilities, saving an AUC-estimated $15,000 annually and time for all parties, and delivering improved approval times.

- The AUC's internal red-tape cutting initiative, Project Green Light, has saved $120,000 per year through changes to AUC notice distribution.
- The AUC's role in Crown consultation with First Nations, where through amendments to AUC Rule 007, the application process has been streamlined with clearly defined information requirements and reduced agency overlap. This is expected to lead to fewer objections to proposed facilities projects by Indigenous peoples while fulfilling and maintaining the honour of the Crown.

AUC Procedures and Processes Review Committee

The most prominent of these third-party reviews was the creation in May 2020 of the AUC Procedures and Processes Review Committee, made up of three veteran, external regulatory experts including accomplished Calgary-based regulatory lawyer Kemm Yates; David J. Mullan, a Queen's University professor emeritus in administrative law; and Rowland J. Harrison, a former long-serving member of the National Energy Board (now the Canada Energy Regulator). The group reviewed the Commission's rate application adjudicative processes and procedures and made sweeping recommendations at www.auc.ab.ca on how AUC process and procedure steps could be made more efficient, or eliminated altogether. All but one of the report's 30 recommendations was accepted; a recommendation that changes to the AUC's legislated timelines may not be required. All other recommendations are being implemented. Among the changes were:

- Adopting an overarching assertive case management approach, designed to improve the ability of proceedings to progress quickly and in a manner well-focused on the issues at hand towards an expeditious and efficient outcome, while maintaining the required procedural fairness. Assertive case management uses a foundational list of issues to shape the relevance and extent of subsequent steps in a proceeding.
- Refining case-management techniques, including issues scoping, increased use of timetables limiting the scope of discovery, refining the use of cross-examination and managing the permissibility of costs to discourage inefficient input. These are all intended to sharpen the focus of proceedings and reduce the time required to complete them.
- Using issues-focused decision templates to produce more concise written decisions that are more closely focused on proceeding issues, to improve comprehensibility and shorten decision-issuance time.

Early results show that the changes implemented, in combination with measures introduced earlier in 2020-21, and prior, are resulting in faster decision issuance. Some examples are:

- The AUC's approval of the 2021 Generic Cost of Capital, which shapes utilities' return on investment, was streamlined in response to the uncertainty of economic and market information due to COVID-19. This drew positive attention from outside Alberta. In credit rating agency Standard & Poor's November 2020 Updates and Insights on Regulatory Jurisdictions it specifically noted the quick resolution the AUC achieved compared to past years, and viewed it as a sign that the provincial regulatory environment could stabilize and potentially improve.
- Eliminating two years of regulatory lag by finalizing going-in rates for the distribution utilities under performance-based regulation (PBR).
- The AUC's changes to simplify compliance filings, where utilities file updated information in response to AUC determinations, are showing real benefits. The AUC is now saving months of time in this area by constraining these filings to more mechanical updates and using a new streamlined process that eliminates interventions. Several utilities have thanked the AUC for this improvement.

- Related to PBR compliance filings, the AUC received positive feedback that regulatory burden has been reduced by recent decisions to limit stand-alone compliance proceedings and simply include them in the annual rate filings.

Mediated Settlements

Following the receipt of an expert third-party report on mediated settlements in November 2020, the AUC moved forward to explore directing more applications to a mediated settlement process, which could reduce proceeding times dramatically and serve as a key plank of the AUC's aspirational goal to be the North American benchmark for operational and regulatory efficiency and effectiveness.

The report, at www.auc.ab.ca, was prepared by four Alberta-based lawyers, each an independent expert in either alternative dispute resolution or regulatory law: John J. Marshall, Bill Kenny, Doug Crowther and Jim McCartney. Historically, the AUC has had an avenue for applicants to pursue negotiated settlements, whereby with the prior consent of the AUC an applicant and interveners negotiate, potentially with AUC monitoring, a proposed agreement themselves. Any proposed negotiated settlement agreement must still be reviewed and accepted by the AUC, to ensure it meets legal requirements and public interest considerations, in order to take effect.

Mediated settlements are different, in that discovery is sharply limited, a mediator is used to reach agreement within 60 days without monitoring by the AUC, and if mediation is successful the applicant and interveners then apply to the AUC with the mediated settlement. Mediated settlements are designed to result in a process that will be less extensive, more cost effective and much shorter than the traditional hearing process, whether the mediation is successful or not.

The AUC is rewriting several of its rules to facilitate mediated settlements and began a pilot project/pilot proceeding in January 2021. If the initial and subsequent pilot proceedings are successful, a material portion of the AUC's rates proceedings could be directed to this channel, potentially reducing average proceeding time dramatically.

Process Improvements and Streamlining

The AUC also continued to implement and identify numerous process improvements and streamlining. Among them were:

- Checklist for applications for low-risk or "trusted traveller" electric transmission and gas utility pipeline applications, and some needs identification document applications. These cut application times and regulatory burden dramatically. For some classes of applications, approval timelines have been cut by more than 50 per cent to seven days, saving Alberta ratepayers $91,000 annually.
- Materiality thresholds were created for review of cost-of-service applications. These cut the volume and detail of expenses being scrutinized to those of a material impact and generally streamlined review.
- Streamlining compliance application processing, which reduced the average time required to issue the decisions by approximately 75 days. The AUC issued 11 expedited decisions under the streamlined process.

Rule Review and Streamlining

Much of the work the AUC does and the manner in which regulated utilities and applicants interact with the Commission is derived from AUC rules, which effectively set out a baseline of how many of the AUC processes will be conducted. The rules are documents setting out new or amended AUC requirements or processes to be implemented and followed by entities under the jurisdiction of the AUC. In 2020-21, the

AUC examined, amended, simplified and modernized numerous rules and worked to eliminate Rule 020: Rules on Gas Utility Pipelines.

The AUC reviewed and updated the AUC Rule 007: Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments. This rule sets out how applications dealing with how utility infrastructure must be approached by applicants. Based on an extensive consultation process focused on developing efficient regulatory requirements to address evolving technologies and emerging issues, requirements were clarified and regulatory burden was reduced. The rule was also modernized in look and readability, user-friendly components were added, and a wiki-style web-based delivery platform was developed and launched. The modernized look, feel, readability and language, as well as interactive functionality, are a model for a general modernization of the AUC rules. The goal is to clarify requirements, enhance comprehension and reduce regulatory burden.

Utility Payment Deferral Program

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

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

During the period from March 18 to June 18, there were approximately 179,000 customers (16 per cent of eligible customers) enrolled in the natural gas deferral program and about 245,000 customers (16 per cent of eligible customers) enrolled in the electricity deferral program. The program applied to bills for residences, farms, and small businesses. In addition, the government ensured that no Albertan was cut off from these services or saw their services reduced while the program was in place. Participants of the program had until June 2021 to repay their deferred payments. The default repayment plan for all consumers was 12 equal monthly installments, interest free. Alternatively, customers had the option of contacting their utility provider to discuss an alternate repayment plan.

The government and the AUC worked with utility companies to develop an approach for repayment that allows consumers to pay back their deferred utility bills within a reasonable time period, and developed an approach so that unpaid deferrals are, over time, covered in rates through a rate rider. This work on completing repayment of deferrals continues into 2021-22, specifically processing applications for unpaid balances owed to funding sources such as the Balancing Pool, the AESO, the government and some retailers, through a rate rider applicable to all Alberta ratepayers, regardless of customer class.

Distribution System Inquiry

In 2020-21, the AUC completed its Distribution System Inquiry, a fundamental deep dive into the evolving nature of electric generation, consumption, storage and the significant implications for the grid, incumbent utilities, consumers, grid managers and the regulatory framework. The inquiry was prompted by anticipated changes in the electric utility sector related to self-supply, electric vehicles, renewables, etc. The inquiry report released in February 2021:

- Identifies opportunities to enable the development of a smarter, more flexible distribution system that will provide benefits for consumers and industry and support the growth of new business.
- Emphasizes that to ensure opportunities afforded by advancements in technology can be realized, the existing system will need to evolve, including removing identified policy and regulatory barriers.
- Notes that achieving this ambition is a shared responsibility among the Government of Alberta, the AESO, the Commission, transmission and distribution facility owners, generators, technology solution providers, and consumer groups, among others.
- Outlines that some of these organizations are already considering the challenges and opportunities technology brings.
- States that any long-term plan requires a coordinated effort to ensure identified work streams are complementary and consistent with the Government of Alberta's long-term strategic framework and policy goals.

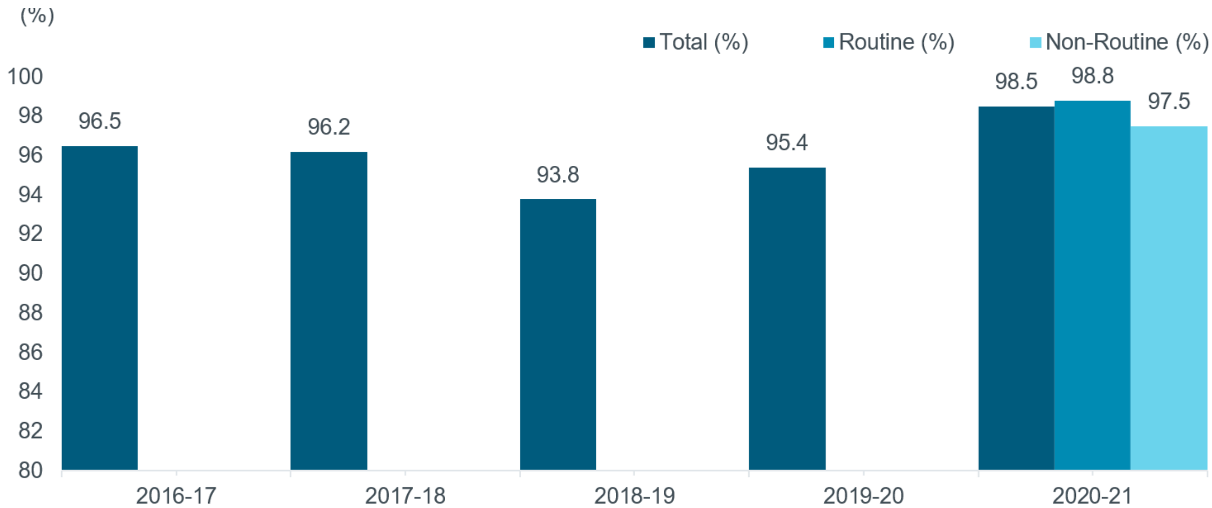
The AUC has identified areas where it can respond to the need for certain improvements, such as the standardization of Alberta distribution utilities terms and conditions of service around connections to distribution systems, and that work is already underway. The standardization of utility terms and conditions of service will simplify and clarify the requirements for Albertans, facilitate investment and help create employment in new generation projects. Additionally, the AUC is taking action to address undue regulatory barriers to new technology adoption, including:

- Working with the government and the AESO to modernizing the regulatory framework for electricity storage.
- Working with the AESO and others, as needed to improve price signal transparency to ensure tariff pricing and wholesale arrangements are properly reflective of the costs and benefits that distributed resources create for the system.
- Reviewing the current system of distribution credits to assess whether they generally reflect system benefits, as part of a longer-term efforts to understand how distribution tariffs need to adapt in the future to deliver efficient outcomes.

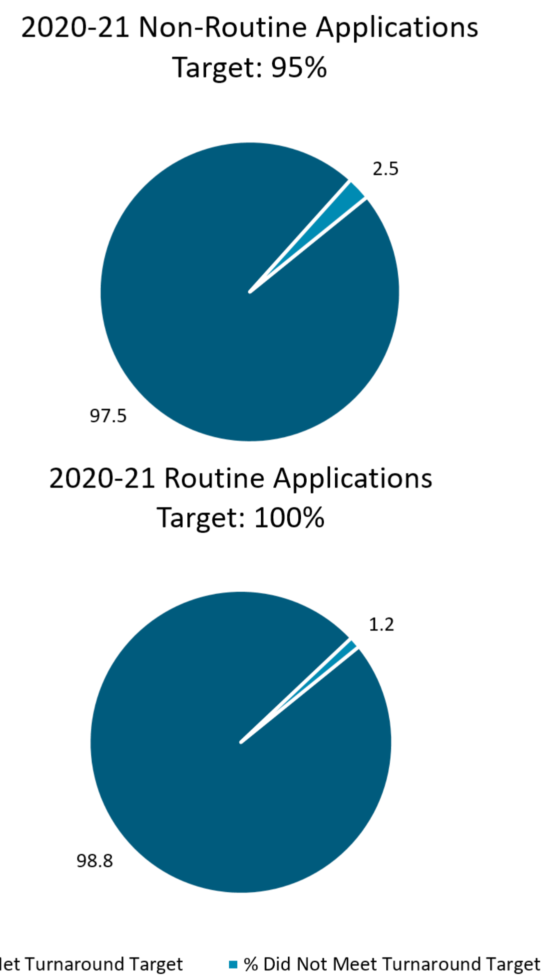
Performance Measure 2.a: Timeliness of application processing (Alberta Energy Regulator)

Target: Applications meet their respective turnaround targets 100 per cent for routine applications and 95 per cent for non-routine applications in 2020-21.

Percentage of Alberta Energy Regulator applications that met turnaround targets



Source: Alberta Energy Regulator[i]



Discussion of Results

The measure indicates the Alberta Energy Regulator's Every application process receives a turnaround target complexity that process represents. This measure monitors the overall efficiency of the AER's application processing, drives internal performance, and provides certainty and transparency to the public related to AER's turnaround targets.

Overall in 2020-21, 98.5 per cent of AER applications met turnaround targets. This result was 3.1 per cent higher than the 2019-20 result. The total number of applications received by the AER decreased from 38,772 in 2019-20 to 29,597 in 2020-21.

Out of 23,513 routine applications, 23,235, or 98.8 per cent met their turnaround targets in 2020-21. This result fell short of its target of 100 per cent by 1.2 per cent. This result can be attributed to a few factors, such as systems outages, supplemental information requests (SIR) to project proponents due to incomplete applications, and bundling multiple applications into one decision on a major project. In the coming fiscal year, AER will be

[i] For more information, see the Performance Measure and Indicator Methodology section on pages 87.

continuing industry education to improve application quality and will be building application closure criteria for applications that are grossly deficient or have excessive SIR response times from project proponents. Continued refinement of AER systems, including adding additional application types to the OneStop system, will help improve this result in the future.

Out of 6,084 non-routine applications, 5,929, or 97.5 per cent met their turnaround targets in 2020-21. This exceeded the 2020-21 target of 95 per cent by 2.5 per cent. The better than expected performance can be attributed to ongoing implementation of the AER's Integrated Decision Approach, and improvements to AER systems to automate low risk application types allowing AER staff to focus on applications that pose the highest risk. Additionally, AER has been diligently working with industry to improve application quality to reduce the number of SIRs to project proponents. In the coming fiscal year, AER will be continuing industry education and will be building application closure criteria for applications that are grossly insufficient or have excessive SIR response times from project proponents. AER will continue to review areas that most impact our ability to meet turnaround targets (including Statements of Concern, SIRs, and deferred decisions at the project proponent's request) and will propose process changes to reduce their effects. These initiatives will contribute to continued improvement in the turnaround targets for non-routine applications.

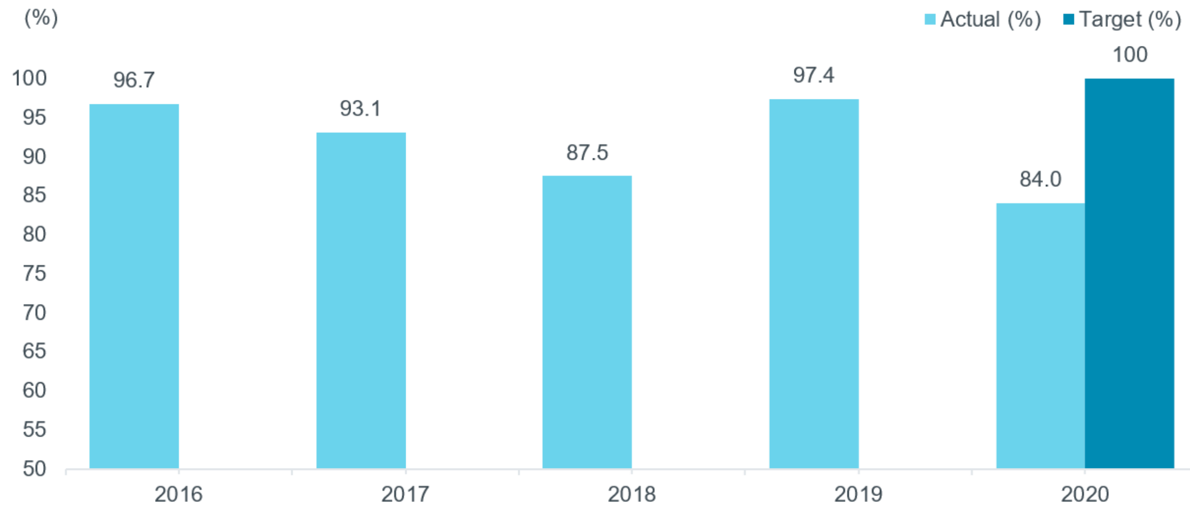
The first year that applications were tracked and separate targets were set for routine and non-routine applications was 2020-21. Each application received by the AER is assessed to determine the risk level and ultimately whether an application is routine or non-routine. An application contains information on the risks associated with energy development. Risks posed to the AER's mandate by energy development are continually assessed throughout the entire energy development's lifecycle. For applications, risks are assessed and based on that assessment, they are either responded to immediately (i.e., a non-routine application) or flagged for potential follow-up later in the energy development's life cycle when it is deemed most effective and efficient to do so. Contextual factors, such as 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 in order to ensure that the risk assessment process remains consistent and accurate.

Application turn around targets for each application process can be found on the AER's website: www.aer.ca.

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

Target: 100 per cent

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



Source: Alberta Utilities Commission[i]

Discussion of Results

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

For 2020, the AUC met this standard 84.0 per cent of the time as 21 of 25 decisions were issued within the 180-day timeline. Factors impacted the results include:

- Process changes from transitioning from oral to written proceedings due to the COVID-19 pandemic;
- Other pandemic-related delays, i.e., development of new protocols for virtual hearings, etc.;
- Requests by applicants to place a proceeding in abeyance while updating the application; and
- Procedural motions that lead to additional processing times.

[i] For more information, see the Performance Measure and Indicator Methodology section on page 87.

Energy Highlights Table

		2019-20	2020-21
Bitumen	Revenue	$4.09 billion	$2.01 billion
	Bitumen wells drilled (1)	1,069 (2019)	503 (2020)
	Total bitumen production in barrels per day (bbl/d)	3.10 million bbl/d (2019)	2.98 million bbl/d (2020)
	Marketable bitumen and Synthetic Crude Oil (SCO) production	2.93 million bbl/d (2019)	2.81 million bbl/d (2020)
Conventional Crude Oil	Revenue	$1.17 billion	$0.47 billion
	Average price for West Texas Intermediate	US$54.85/bbl	US$42.32/bbl
	Conventional crude oil production	0.49 million bbl/d (2019)	0.42 million bbl/d (2020)
	Pentanes and condensate production	0.34 million bbl/d (2019)	0.33 million bbl/d (2020)
	Crude oil wells drilled (1)	1,755 (2019)	1,014 (2020)
Total Crude and Equivalent	Production (conventional, marketable bitumen and SCO, pentanes plus and condensates)	3.75 million bbl/d (2019)	3.56 million bbl/d (2020)
	Removals from Alberta	3.64 million bbl/d (2019)	3.48 million bbl/d (2020)
	Per cent of total crude oil and equivalent disposition	87% (2019)	88% (2020)
Natural Gas and By-Products	Revenue	$0.37 billion	$0.47 billion
	Average Alberta Gas Reference Price	$1.39/GJ	$2.10/GJ
	Number of conventional natural gas wells drilled (1)	687 (2019)	598 (2020)
	Total marketable natural gas production including Coalbed Methane (CBM)	3.63 Tcf (2019)	3.45 Tcf (2020)
	Coalbed Methane production	0.16 Tcf (2019)	0.17 Tcf (2020)
	Total natural gas deliveries	4.28 Tcf (2019)	4.97 Tcf (2020)
	* To the United States	32%	34%
	* Within Alberta	46%	39%
	* To rest of Canada	22%	26%
Bonuses and Sales of Crown Leases	Revenue from bonuses and sales of Crown leases	$0.12 billion	$0.024 billion
	Revenue from rentals and fees	$0.17 billion	$0.12 billion
	Average price per hectare (ha) paid at petroleum and natural gas rights sales	$137.15	$135.63

		2019-20	2020-21
	Petroleum and natural gas hectares sold at auction	774,896.36 ha	152,504.906ha
	Average price per hectare paid for oil sands mineral rights	$111.59	$89.04
	Oil sands hectares sold at auction	99,464 ha	39,192 ha
Freehold Mineral Tax	Revenue	$75 million	$60 million
Wells and Licences	Well Licences issued	5,160 (2019)	2,081 (2020)
	Industry drilling (2)	4,464 (2019)	2,587 (2020)
Coal	Revenue	$13 million	$12 million
	Established coal reserves (estimate)	33.2 billion tonnes	33.2 billion tonnes
	Raw coal production	24.8 million tonnes (2019)	18.8 million tonnes (2020)
	Total marketable coal deliveries	19.6 million tonnes (2019)	17.9 million tonnes (2020)
	Percentage of total coal deliveries exported out of province	30.7% (2019)	38.2% (2020)
Electricity	Total generation capacity in Megawatts (MW)	16,515 (2019)	16,803 (2020)
	Total generation capacity from renewable sources in MW	3,028 (2019)	3,194 (2020)
	Total generation capacity from coal in MW	5,273 (2019)	5,574 (2020)
Metallic and Industrial Minerals	Metallic and Industrial minerals Royalty Revenues (MINRS)	$732,016	$856,935
	Hectares of mineral permits issued to exploration companies (LAMAS,MIM Permits and New Application Issued)	0.9 million ha	0.6 million ha
Energy Sector Employment (3)		142,000 (2019)	129,000 (2020)
Energy Sector Investment (4)		$25.1 billion (2019)	Estimated $16.6 billion (2020)

Notes:

1. Data on wells drilled include both development and exploratory wells.
2. 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.
3. Presentation of the employment results has been changed from the previous Annual Report following the methodology review. The revision is reflected in both the Alberta's Energy Resource Sector section above and in the Energy Highlights table. The result for 2019 has been retroactively adjusted.
4. Investment data results for 2019 have been retroactively adjusted to reflect the updates that took place since the publication of the 2019-20 Annual Report.

Performance Measure and Indicator Methodology

Performance Measure 1.a

Alberta's oil sands supply share of global oil consumption

Methodology

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

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

The total for annual barrels of Alberta oil sands production is the sum of total mined and in-situ bitumen production in any given calendar year. Bitumen production data is calculated from Alberta Energy Regulator's 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

Production: Alberta's crude oil and equivalent annual production; and Alberta's total marketable natural gas annual production

Methodology

Alberta's crude oil and equivalent annual production

The crude oil and equivalent annual production portion of the indicator consists of three components:

- Volume (thousands of barrels/day);
- As a percentage of Canadian production;
- Total percentage of crude oil leaving Alberta.

The indicator reports the volume of Alberta's annual crude oil and equivalent production, Alberta's share of total Canadian production, and total percentage of Alberta disposition, which is leaving Alberta.

It demonstrates the vital role that Alberta has in the Canadian oil market context. Components one and two of the indicator focus only on the production of crude oil and equivalent. Alberta's crude oil and equivalent production consists of conventional crude production, marketable oil sands production (which consists of non-upgraded bitumen and upgraded bitumen), and condensate and pentanes plus. All data for components one and two of the indicator is taken from the Canada Energy Regulator (CER). Generally, the Ministry of Energy relies on the Alberta Energy Regulator to report Alberta oil statistics. However, as the requirement of the indicator is to compare Alberta with the rest of Canada, the CER is used as a source to avoid mixing the sources.

For the third component of this indicator, the Ministry of Energy reports the share of total volume that leaves Alberta as a percentage of total Alberta oil disposition. All data for this component is calculated from the AER's reports.

Alberta's total marketable natural gas annual production

The total marketable natural gas production portion of the indicator consists of three components:

- Volume (billion cubic feet/day);
- As a percentage of Canadian production;
- Total percentage of natural gas leaving Alberta.

The indicator reports the volume of Alberta's marketable natural gas production, Alberta's share of total Canadian production, and total percentage of Alberta disposition, which is leaving Alberta.

Components one and two of the indicator focus only on the production of marketable natural gas. The indicator has been reporting the volume of Alberta's annual gas production, as well as Alberta's share of total Canadian production. It demonstrates the vital role that Alberta has in the Canadian gas market context. For this indicator, the Ministry of Energy reports total marketable natural gas production volumes.

All data for the present indicator is taken from the CER. Generally, the ministry relies on AER to report Alberta gas statistics. However, as the requirement of the present indicator is to compare Alberta with the rest of Canada, the CER is used as a source to avoid mixing the sources.

For the third component of this indicator, the Ministry of Energy reports the share of total volume that leaves Alberta as a percentage of total Alberta gas disposition. All data is calculated from the AER's reports.

Performance Indicator 1.c

Investment: Upstream and Downstream

Methodology

Upstream: Mining, Quarrying, and Oil and Gas industry investment in Alberta

The upstream portion of the indicator consists of the following components:

- $ Billions
- Alberta as a Percentage of Canadian investment

This portion of the indicator reports investment in Alberta's Mining, Quarrying, and Oil and Gas Extraction sector. It also puts Alberta in the national context, by reporting Alberta's mining, quarrying, and oil and gas investment as a percentage of total Canadian investment in the sector.

The data for the indicator are taken from Statistics Canada. Data are reported on a calendar year basis.

Downstream: Petroleum, Coal and Chemical Manufacturing

The downstream portion of the indicator consists of the following components:

- $ Billions
- Alberta as a percentage of Canadian investment

In addition to upstream investment, the energy industry generates significant downstream activity; this portion of the indicator focuses on the investment impacts of the downstream activity. The indicator is explicitly focused on petroleum and coal product manufacturing, and chemical manufacturing; this allows for the coverage of petroleum refining and petrochemical manufacturing activity, among other downstream activities.

The "Downstream: Petroleum, Coal and Chemical Manufacturing" portion of the indicator can be treated as complementary to the "Upstream: Mining, Quarrying, and Oil and Gas industry investment in Alberta" portion of the indicator. There is no overlap between the data reported by both portions of the indicator, as they are based on different industrial categories.

Just like investment data in the "Upstream: Mining, Quarrying, and Oil and Gas industry investment in Alberta", data for the "Downstream" portion of the indicator are taken from Statistics Canada. Data are reported on a calendar year basis.

In addition to actual results, both the "Upstream" and "Downstream" components of the present indicator also report the most current preliminary actual results, to enhance the timeliness of data presentation. The preliminary actual results will be revised once the actual results become available.

Performance Measure 2.a

Timeliness of application processing (Alberta Energy Regulator)

Methodology

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

- Integrated Application Registry (IAR) – IAR is the application workflow system used for most applications regulated under the *Oil & Gas Conservation Act, Oil Sands Conservation Act, Coal Conservation Act,* and *Pipeline Act*.
- PLA AppTracker – The PLA AppTracker is a Microsoft Access solution used to track applications submitted under the *Public Lands Act* (PLA).
- AppTracker – The AppTracker is a Microsoft Access solution used to track applications submitted under the *Environmental Protection and Enhancement Act* (EPEA), the *Water Act*, and applications that are not captured in IAR.
- OneStop – OneStop is the new application workflow system being developed and implemented to eventually encompass all AER applications. Pipeline applications, *Water Act* approvals, land use applications, new well applications, and reclamation certificates are processed through OneStop. Well amendment applications are scheduled to be processed in OneStop in Q3 2020-21FY. All data from OneStop with the exception of reclamation certificates has been incorporated into this metric. It is expected that reclamation certificate data will be added in the 2020-21FY.
- Structured Review Tool (SRT): The SRT provides a consistent and focused way to review elements of submissions that have been identified as high risk or uncertain.

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

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

Source

Alberta Energy Regulator

Performance Measure 2.b

Timeliness of the needs and facility applications (Alberta Utilities Commission)

Methodology

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

Source

Alberta Utilities Commission

Performance Indicator 2.c

Regulatory enforcement (Alberta Energy Regulator)

Methodology

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

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

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

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

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

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

Source

Alberta Energy Regulator

Performance Indicator 2.d

Pipeline safety (Alberta Energy Regulator)

Methodology

A reportable pipeline incident under the Alberta Energy Regulator'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 (FIS) database by AER inspectors. The incident information is used to assign a consequence rating by the AER to indicate the severity of the incident. High consequence pipeline incidents are those that could have significant impacts to the public, wildlife, or the environment, or that involve the release of a substance that affects a large area or water body. Records are reviewed for accuracy and consistency.

Source

Alberta Energy Regulator

Performance Indicator 2.e

Annual Wells Decommissioned (Alberta Energy Regulator)

Methodology

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

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

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

- Critical sour wells (perforated or not) that have not reported any type of volumetric activity (production, injection or disposal) for six consecutive months;
- All other wells that have not reported volumetric activity (production, injection or disposal) for 12 consecutive months.

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

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

Source

Alberta Energy Regulator

Financial Information

Year Ended March 31, 2021

Table of Contents

Reporting Entity and Method Consolidation

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

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

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

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

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

Ministry Financial Highlights

Statement of Revenues and Expenses (Unaudited)

Year Ended March 31, 2021

	2021		2020	Change from	
	Budget	Actual	Actual (Restated)	Budget	2020 Actual (Restated)
		(in thousands)			
Revenues					
Non-Renewable Resource Revenue					
Bitumen Royalty	$ 3,211,000	$ 2,005,884	$ 4,088,981	$ (1,205,116)	$ (2,083,097)
Crude Oil Royalty	1,135,000	465,970	1,174,553	(669,030)	(708,583)
Natural Gas and By-Products Royalty	429,000	465,162	371,938	36,162	93,224
Bonuses and Sales of Crown Leases	177,000	23,731	119,832	(153,269)	(96,101)
Rentals and Fees	126,000	118,094	169,189	(7,906)	(51,095)
Coal Royalty	11,000	12,032	12,785	1,032	(753)
Total Non-Renewable Resource Revenue	5,089,000	3,090,873	5,937,278	(1,998,127)	(2,846,405)
Freehold Mineral Rights Tax	67,000	59,818	75,035	(7,182)	(15,217)
Transfers from Government of Canada	-	127,954	-	127,954	127,954
Industry Levies and Licenses	331,576	212,780	330,581	(118,796)	(117,801)
Other Revenue	1,842	4,704	7,777	2,862	(3,073)
Net Income (Loss) from Government Business Enterprises					
Alberta Petroleum Marketing Commission	(263,604)	(1,854,102)	(2,677,862)	(1,590,498)	823,760
The Balancing Pool	135,400	(112,770)	161,231	(248,170)	(274,001)
Ministry total revenues	5,361,214	1,529,257	3,834,040	(3,831,957)	(2,304,783)
Inter-ministry consolidation adjustments	-	(212)	(457)	(212)	245
Ministry total revenues	5,361,214	1,529,045	3,833,583	(3,832,169)	(2,304,538)
Expenses - Directly Incurred					
Ministry Support Services	7,368	5,373	5,891	(1,995)	(518)
Resource Development and Management	85,908	58,687	78,440	(27,221)	(19,753)
Cost of Selling Oil	84,000	46,308	83,627	(37,692)	(37,319)
Climate Change	28,637	20,598	89,359	(8,039)	(68,761)
Carbon Capture and Storage	146,144	126,575	60,476	(19,569)	66,099
Market Access	-	442,530	866,098	442,530	(423,568)
Economic Recovery Program	-	129,640	-	129,640	129,640
Energy Regulation	215,859	203,753	264,248	(12,106)	(60,495)
Utilities Regulation	32,554	30,479	32,434	(2,075)	(1,955)
Orphan Well Abandonment	69,000	65,698	61,039	(3,302)	4,659
Ministry total expenses	669,470	1,129,641	1,541,612	460,171	(411,971)
Inter-ministry consolidation adjustments	-	(441)	(738)	(441)	297
Adjusted ministry total expenses	669,470	1,129,200	1,540,874	459,730	(411,674)
Annual Surplus before inter-ministry consolidation adjustment	4,691,744	399,616	2,292,428	(4,292,128)	(1,892,812)
Inter-ministry consolidation adjustments	-	229	281	229	(52)
Adjusted annual surplus	$ 4,691,744	$ 399,845	$ 2,292,709	$ (4,291,899)	$ (1,892,864)

Revenue and Expense Highlights

Revenues

Energy's 2020-21 total revenues of $1.59 billion consist of the following:

- **Non-Renewable Resource** revenues totalling $3.09 billion was $2 million lower than budgeted primarily due to lower Bitumen Royalties ($1.21 million). The decrease was primarily due to lower than forecast West Texas Intermediate (WTI) and Western Canadian Select (WCS) prices.
- **Freehold Mineral Rights Tax** revenues totalled $59 million and relate to annual taxes on private freehold mineral rights.
- **Industry levies and licences** totalled $213 million and relate to levies and licences collected from industry by the Alberta Energy Regulator (AER) and the Alberta Utilities Commission (AUC). Industry levies and licences were $118 million under budget due to the first six months of AER's levies being funded by the Department of Energy.
- **Transfers from Government of Canada** totalling $128 million in revenues recognized to offset grant expenses incurred for Site Rehabilitation Program. During the year, the ministry received $1 billion from the federal government's COVID-19 Economic Response Plan of which $872 million has been recognized as deferred contributions to be expended in future years of the program.
- **Net Losses from Government Business Enterprises** totalling $1.97 billion was lower than budget by $1.84 billion primarily due to lower than anticipated income from the Alberta Petroleum Marketing Commission (APMC) resulting in a variance of $1.59 billion due to the fair value loss on investment in Keystone XL Expansion Project. The remaining $248 million variance is attributable to lower than anticipated sales of electricity realized by the Balancing Pool as a result of COVID-19 closures.

Expenses

Energy's 2020-21 operating expenditures totalled $1.1 billion, with an operating surplus of $460 million compared to budget and decreased spending of $412 million compared to 2019-20. This was primarily related to:

- **Market Access** – This program consists primarily of the Crude by Rail program. In 2020-21, the Crude by Rail program incurred unbudgeted costs of $443 million. This was primarily due to delays in divesting the program due to a downturn in the economy and adverse market conditions. The 2020-21 budget originally anticipated the completion of divestment in 2019-20. The current fiscal environment, due to COVID-19, created additional challenges for the APMC to complete the assignment process and be fully divested. Negotiations for divestiture are ongoing. The year over year decrease of $424 million was due to lower divestment and operating costs as compared to 2019-20.
- **Economic Recovery Program** – The costs included in this program relate to the Site Rehabilitation Program. This program was not included in Energy's 2020-21 budget, as it was launched by government in May 2020, and was funded mainly through $1 billion in federal relief funding. In 2020-21, the ministry incurred $130 million in operating and grant expenditures to support this program.
- **Cost of Selling Oil** – This program includes the costs incurred by the APMC to sell crude oil royalties on behalf of the ministry. These costs were $38 million lower than budget and $37 million lower than previous year actuals, due primarily to lower market prices as a result of the oil price war that occurred in 2020 and the economic downturn.

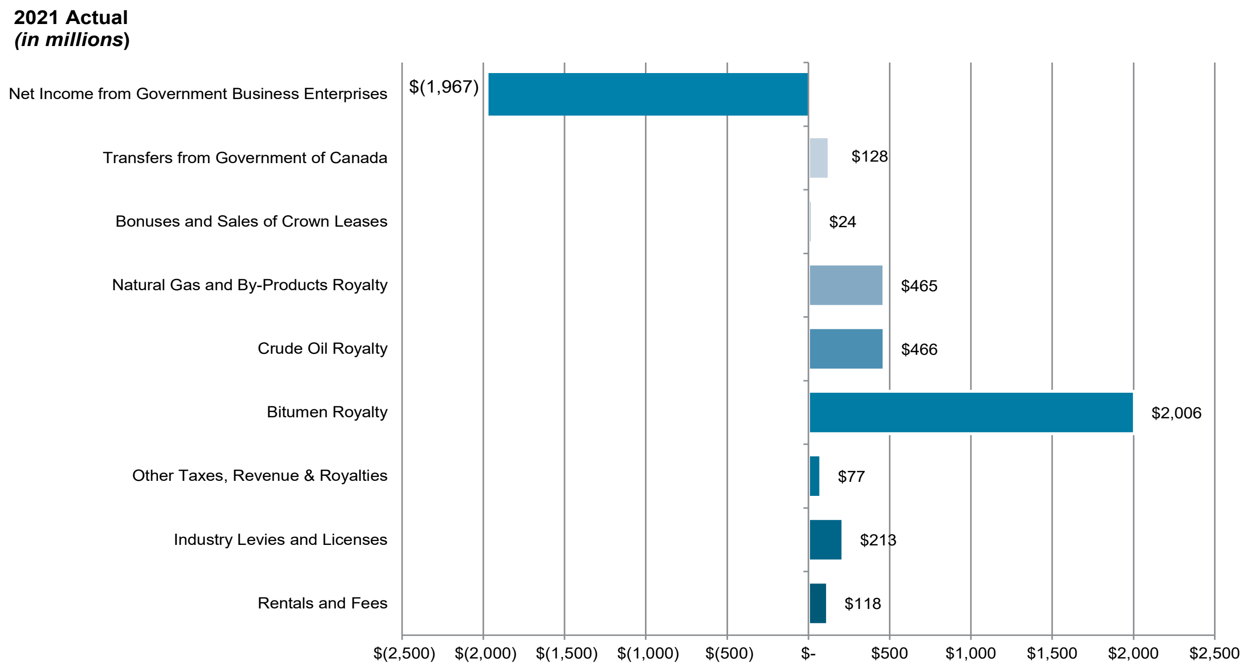
Continued...

Revenue and Expense Highlights...Continued

- **Carbon Capture and Storage** – This program supports two Carbon Capture and Storage projects in Alberta: the Shell Quest Project and the Alberta Carbon Trunk Line Project (ACTL). Due to construction delays, this program incurred lower than anticipated costs compared to budget of $20 million. The year over year increase in spending of $66 million was due to the timing of payments related to milestone achievements as the ACTL project achieved commercialization in 2020-21.
- **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.
  - In 2020-21, the AER had an operating surplus of $12 million compared to budget. This is primarily in response to the economic downturn and COVID-19. This also resulted in a $60 million reduction in spend as compared to the previous year, primarily due to severance and higher labour costs due to timing of staff reductions that occurred in 2019-20.
- **Resource Development and Management** – Resource development and management captures the costs incurred by the ministry to support various energy policy and operations activities. These activities have an approved budget of $86 million.
  - **Energy Policy (Budget: $37 million)** – The ministry develops strategic policies to support Alberta's energy and mineral resource markets and electricity systems. The ministry incurred a surplus of $4 million primarily due to lower than anticipated labour costs due to attrition, delays in hiring and a reduction in discretionary spending.
  - **Energy Operations (Budget: $19 million)** – The ministry oversees Alberta's energy, mines and minerals royalty and tenure systems (which includes the calculation and collection of revenues from energy and mineral royalties, mineral rights leases, and bonuses and rent). The ministry experienced a $3 million deficit primarily due to allowances booked for doubtful accounts ($7 million) as a result of economic conditions, partially offset by lower than anticipated labour costs due to attrition, delays in hiring and a reduction in discretionary spending.
  - **Industry Advocacy (Budget: $30 million)** – The ministry ensures misinformation about Alberta's energy industry is addressed, which includes activities associated with the Canadian Energy Centre (CEC). This program was reduced by $26 million due to cost saving measures in response to the economic downturn and COVID-19.
- **Climate Change** – The costs included in this program relate to the Renewable Electricity Program and the annual payments for the Coal Phase-Out Agreements. The ministry incurred an $8 million surplus in Climate Change due primarily to lower expense related to the Coal Phase-Out Agreements as a result of a settlement. The year over year decrease of $69 million is primarily associated with the cancellation of the Regulated Rate Option rate cap program in 2019-20.

Breakdown of Revenues (Unaudited)

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



Non-Renewable Resource Revenue

Revenue ($ Millions)	2020-21 Budget	2020-21 Actual
Bitumen Royalty	$3,211	$2,006
Crude Oil Royalty	1,135	466
Natural Gas & By-Products	429	465
Bonus and Sales of Crown Leases	177	24
Rentals and Fees	126	118
Coal Royalty	11	12
Non-Renewable Resource Revenue	$5,089	$3,090

Source: Government of Alberta

- **Bitumen** royalties remained the largest portion of resource royalty revenue. In 2020-21, bitumen revenue totaled $2.0 billion. Actual bitumen royalties were about 38 per cent, or $1,205 million lower than budgeted. This variance is mainly due to the significantly lower WTI and WCS prices for the fiscal year. This variance is mainly due to the significantly lower WTI and WCS prices for the fiscal year and lower bitumen production.
- **Conventional crude oil** royalties contributed $466 million. Conventional crude oil royalties were $669 million, or 59 per cent lower than the budgeted amount mainly due to the significantly lower than forecast WTI prices for the fiscal year.
- **Natural gas and by-products** brought in $465 million and were $36 million or 8 per cent above the budgeted amount. The favorable variance is attributable to higher than budgeted Alberta Reference Price and substantially lower royalty program costs.

Continued...

Breakdown of Revenues (Unaudited)...Continued

- In 2020-21, **Bonuses and Sales of Crown Leases** totaled $24 million, which was $153 million or 87 per cent lower than the budgeted amount. As a result of COVID-19, the Department of Energy deferred sales for much of the fiscal year, resulting in drastically lower revenue.
- Revenue from **Rentals and Fees** was $118 million in 2020-21, lower than the budgeted revenue by $8 million, or 6 per cent. Rentals and fees revenue is tied to land sales in the current and the previous years. In that, a lease or license holder has to pay rent every year and are also required to pay upfront the first year of rent in full when the their bid wins the bonus auction. Revenue was slightly lower due to the deferral of land sales for much of the fiscal year, resulting in lower rental revenue from new hectares sold. However this decrease was much less dramatic than for Bonuses and Sales of Crown Leases, as Rentals and Fees are less affected by a one year impact due to their long term nature.
- In 2020-21, the ministry recognized $128 million in **Transfers from Government of Canada** to offset grant expenses incurred for Site Rehabilitation Program. This funding was provided as part of the federal government's response to the COVID-19 Economic Response Plan, which was not included in Energy's 2020-21 budgeted revenues.
- Included in other taxes, revenue and royalties totaling $77 million is revenue from coal royalty, which brought in $12 million which was $1 million higher than budgeted. Also included is freehold mineral rights tax revenue, which was $60 million and was $7 million lower than budget. This was caused mainly by a lower unit value for oil, as well as lower gas and oil production than forecast.

Royalty Program Adjustments

The ministry has a number of royalty programs under the Alberta Royalty Framework, which no longer accept new participants as of 2017 and will be phased out once their regulation expires. The programs to be phased out include the Natural Gas Deep Drilling Program, Emerging Resources and Technologies Initiative, Incremental Ethane Extraction Program and the Enhanced Oil Recovery Program. The ministry will continue to monitor and report on the progress of all royalty programs until they have officially expired.

In 2020-21, Non-Renewable Resource Revenues are reported net of the following royalty program adjustments:

	2021	2020
	(in thousands)	
Royalty Program:		
Natural Gas Deep Drilling Program	142,838	$ 354,437
Shale Gas	7,260	68,758
Horizontal Oil	531	9,207
Incremental Ethane Extraction Program	11,331	14,489
Enhanced Oil Recovery Program	5,201	15,985
Proprietary Waiver	2,497	2,001
Horizontal Gas	496	949
Otherwise Flared Solution Gas	115	151
Coalbed Methane	4	4
Total Royalty Program Adjustment	$ 170,273	$ 465,982

Continued...

Breakdown of Revenues (Unaudited)...Continued

Revenue from Other Government Organizations

- Industry levies and licences totalled $213 million which primarily includes $183 million from AER and $30 million from AUC. Industry levies and licences were $118 million under budget due to the first six months of AER's levies being funded by the Department of Energy. These payments totalling $113 million were eliminated via intra-ministry consolidation. The intra-ministry grant was part of the government's COVID-19 response initiatives targeted at providing economic relief to Alberta's energy industry.

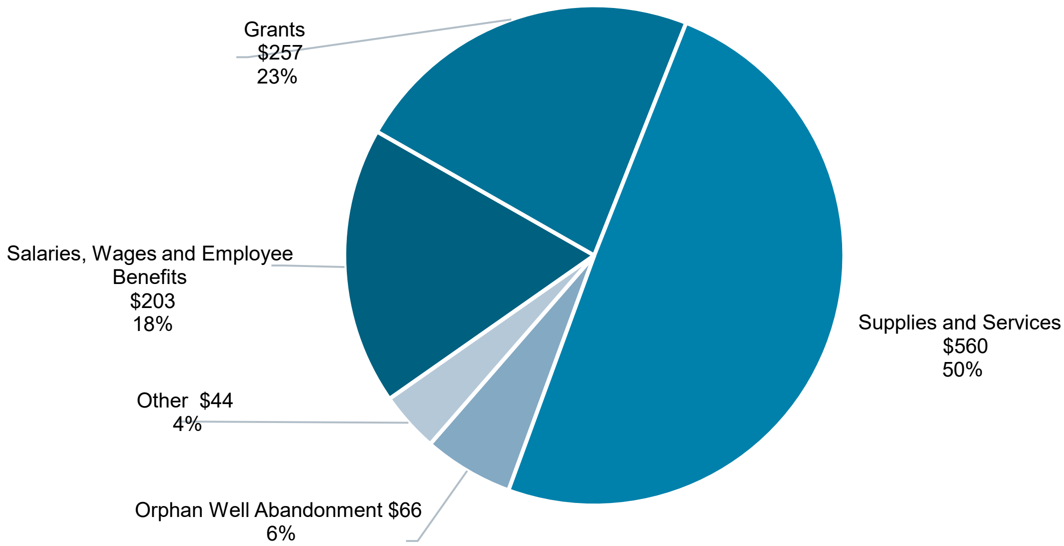
Net Income/(Loss) from Government Business Enterprises

- Net losses from Government Business Enterprises is comprised of the net losses from the Balancing Pool (BP) of $113 million and net losses from the APMC of $1.85 billion.
- BP's net income of $113 million in 2020-21 increased the accumulated deficit from an opening balance of $667 million to $780 million as of March 31, 2021. Lower than budgeted net income of $248 million was attributed to lower sales of electricity, and change in the fair value of Hydro Power Purchase Agreements, which were negatively impacted by lower than anticipated market prices.
- The APMC's net loss of $1.85 billion in 2020-21 increased the accumulated deficit from an opening balance of $2.79 billion to $4.64 billion as of March 31, 2021. The net loss was driven primarily by:
  - Loss allowance for the Keystone XL Expansion Project debt guarantee of $1.04 billion.
  - Fair value loss on investment in Keystone XL Expansion Project of $256 million as a result of the exit agreement with TransCanada Pipeline Ltd. (TCPL) for the dissolution of the partnership as a result of TCPL's exit from the project subsequent to year-end.

Expenses – Directly Incurred Detailed by Object (Unaudited)

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

2021 Actual
(in milions)



- **Supplies and Services,** which represented 50 per cent of total operating expense, were the largest component of the ministry's operating expense ($560 million). This consisted primarily of the costs related to the Crude by Rail program ($443 million). The remainder primarily consisted of ongoing supply requirements for the ministry (i.e., contracts and contract services, materials and supplies, and shared services provided by the Ministry of Service Alberta).
- **Grants**, which represented 23 per cent of total operating expense, were the second largest component of the ministry's operating expense ($257 million), primarily consisted of payments related to the Site Rehabilitation Program ($128 million) and Carbon Capture and Storage projects ($127 million).
- **Salaries, Wages and Employee Benefits**, which represented 18 per cent of total operating expense ($203 million), and primarily support the collection of revenue, development of resource policy, regulatory work provided by AER and AUC, and the overall support and management of ministry operations.
- **Orphan Well Abandonment** expenses, totalling $66 million (six per cent), relate to the remittance of levies collected on behalf of the Orphan Well Association for the reclamation of abandoned wells, facilities and pipelines that are licensed to defunct licensees, as delegated by AER.
- **Other expenses**, totalling $44 million (four per cent), primarily consist of accretion expenses related to the off coal agreements ($18 million), amortization of tangible capital assets ($18 million), and allowances for doubtful accounts ($7 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, 2021, the Ministry of Energy has gas royalty deposits of $154 million.

Coal Phase-Out Agreements

- On November 24, 2016, the Minister of Energy, on behalf of the Province of Alberta, reached agreements with three coal-fired generators to cease operations on or before December 31, 2030. The coal-fired generation plants covered under agreements include: Sheerness 1 and 2; Genesee 1, 2, and 3; and Keephills 3.
- The Ministry of Energy will make payments totalling $97 million annually to the three generators. The first payment was made July 31, 2017 and payments will continue for the next 10 years. In return, the coal-fired plants named above will meet a number of conditions on an annual basis and will cease operations in the coal-fired electricity generation plants on or before December 31, 2030. These conditions are specific to each party, generally requiring each of the coal-fired generator owners to spend a minimum specified amount in the communities in which the plants were located, along with future specified value of investment and investment related activities in Alberta with respect to the electricity business.
- The present value of the remaining 10 payments, discounted at 3 per cent (representing the government's average 10-year bond rate at time of negotiations), is $960 million. The amount of the draw down over the next five years and thereafter are as follows:

(in thousands)

	Annual Payment	Principal	Interest
2021-22	96,024	72,640	23,384
2022-23	96,024	74,845	21,179
2023-24	96,024	77,117	18,907
2024-25	96,024	79,457	16,567
2025-26	96,024	81,869	14,155
Thereafter	480,115	448,163	31,952
	$ 960,235	$ 834,091	$ 126,144

COVID-19

Alberta Energy Regulator Levy

- On March 20, 2020, the Government of Alberta announced it would provide immediate relief for the energy sector through the funding of the industry levy for the first six months of fiscal year 2020-21. The department provided the Alberta Energy Regulator (AER) with payments totalling $113 million which represents six months of the AER's 2020-21 administrative fees that would otherwise been collected from industry. This commitment was part of the government's COVID-19 response initiatives targeted at providing economic relief to Alberta's energy industry.

Utility Payment Deferral Program

- On May 8, 2020, the government passed the *Utility Payment Deferral Program Act* which allowed those experiencing financial hardship as a direct result of COVID-19 to defer their utility payments without any late fees or added interest payments from March 18, 2020 to June 18, 2020. The utility deferrals for natural gas service providers totalled $37 million of which $30 million was repaid during the year. The remaining deferral amount of $7 million is recorded as a loan receivable and is expected to be fully recovered by utility companies via rate riders by June 18, 2021. The government is expecting to be fully reimbursed by the end of the rate rider period ending June 18, 2022.

Financial Statements of Other Reporting Entities

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Alberta Energy Regulator

Consolidated Financial Statements

For the year ended March 31, 2021

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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, 2021, and the consolidated statements of operations, change in net debt, and cash flows for the year then ended, and notes to the consolidated financial statements, including a summary of significant accounting policies.

In my opinion, the accompanying consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Group as at March 31, 2021, and the results of its operations, its changes in net debt, 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 13, 2021
Edmonton, Alberta

Consolidated Statement of Operations

Aberta Energy Regulator
Year ended March 31, 2021

	2021		2020
	Budget (Note 4, Schedule 3)	Actual	Actual
		(in thousands)	
Revenues			
Administration fees	$ 226,450	$ 114,240	$ 233,393
Government of Alberta grant		113,000	-
Orphan fund levy and fees (Note 5)	69,000	65,698	61,039
Information, services and fees	3,542	2,731	4,693
Investment income	867	359	555
	299,859	296,028	299,680
Expenses			
Energy regulation (Schedule 1)	215,859	203,753	264,248
Orphan well abandonment (Note 5)	69,000	65,698	61,039
	284,859	269,451	325,287
Annual operating surplus (deficit)	15,000	26,577	(25,607)
Accumulated surplus at beginning of year	40,910	40,910	66,517
Accumulated surplus at end of year	$ 55,910	$ 67,487	$ 40,910

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

Consolidated Statement of Financial Position

Aberta Energy Regulator
As at March 31, 2021

	2021	2020
	(in thousands)	
Financial assets		
Cash and cash equivalents (Note 6)	$ 26,226	$ -
Accounts receivable (Note 7)	1,456	1,920
Pension assets (Note 12)	4,923	1,505
	32,605	3,425
Liabilities		
Bank indebtedness (Note 6)	-	812
Accounts payable and other accrued liabilities (Note 8)	18,362	17,955
Payable to Orphan Well Association	1,942	609
Deferred lease incentives (Note 10)	14,332	15,949
	34,636	35,325
Net debt	(2,031)	(31,900)
Non-financial assets		
Tangible capital assets (Note 13)	60,133	63,105
Prepaid expenses and other assets	9,385	9,705
	69,518	72,810
Net assets		
Accumulated surplus (Note 14)	$ 67,487	$ 40,910

Contingent liabilities (Note 15)
Contractual obligations (Note 16)

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

Consolidated Statement of Change in Net Debt

Aberta Energy Regulator
Year ended March 31, 2021

	2021		2020
	Budget (Note 4, Schedule 3)	Actual	Actual
		(in thousands)	
Annual operating surplus (deficit)	$ 15,000	$ 26,577	$ (25,607)
Acquisition of tangible capital assets (Note 13)	(14,500)	(13,697)	(12,704)
Amortization of tangible capital assets (Note 13)	16,000	15,686	15,947
Loss on disposal and write-down of tangible capital assets		983	67
Decrease in prepaid expenses and other assets		320	1,033
Decrease/(increase) in net debt	16,500	29,869	(21,264)
Net debt at beginning of year	(31,900)	(31,900)	(10,636)
Net debt at end of year	$ (15,400)	$ (2,031)	$ (31,900)

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

Consolidated Statement of Cash Flows

Aberta Energy Regulator
Year ended March 31, 2021

	2021	2020
	(in thousands)	
Operating transactions		
Annual operating surplus (deficit)	$ 26,577	$ (25,607)
Non-cash items included in annual operating surplus (deficit):		
Amortization of tangible capital assets (Note 13)	15,686	15,947
Loss on disposal and write-down of tangible capital assets	983	67
(Increase)/decrease in pension assets	(3,418)	636
Amortization of deferred lease incentives (Note 10)	(1,617)	(1,619)
	38,211	(10,576)
Decrease in accounts receivable	464	5,564
Decrease in prepaid expenses and other assets	320	1,033
Increase/(decrease) in accounts payable and other accrued liabilities	407	(2,550)
Increase/(decrease) in payable to Orphan Well Association	1,333	(1,319)
Cash provided by (applied to) operating transactions	40,735	(7,848)
Capital transactions		
Acquisition of tangible capital assets (Note 13)	(13,697)	(12,704)
Cash applied to capital transactions	(13,697)	(12,704)
Financing transactions		
Proceeds from line of credit	9,855	64,587
Debt repayment	(10,667)	(63,775)
Cash (applied to) provided by financing transactions	(812)	812
Increase/(decrease) in cash and cash equivalents	26,226	(19,740)
Cash and cash equivalents at beginning of year	-	19,740
Cash and cash equivalents at end of year	$ 26,226	$ -

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

Notes to the Consolidated Financial Statements

Aberta Energy Regulator
March 31, 2021

Note 1 AUTHORITY

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

Note 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES

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

Reporting Entity and Method of Consolidation

The consolidated financial statements reflect the assets, liabilities, revenues and expenses of the AER, which is composed of all components controlled by the AER. The Orphan Fund is a fund retained and administered by the AER. The AER collects the orphan fund levy and first time licensee application fees, and transfers the funds to the Orphan Well Association. 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. Cash received for which services have not been provided by year end is recognized as unearned revenue and recorded in accounts payable and other accrued liabilities.

Government of Alberta Grant

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).

Investment Income

Investment income includes interest income.

Expenses

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

Employee future benefits

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

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

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

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

Notes to the Consolidated Financial Statements

Aberta Energy Regulator
March 31, 2021

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

Basis of Financial Reporting (continued)

Actuarial gains and losses are amortized over the average remaining service period of the active employees, which is 11.2 years (2020 - 10.9 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
Bank indebtedness	Cost
Accounts payable and other accrued liabilities	Cost
Payable to the Orphan Well Association	Cost
Deferred lease incentives	Amortized cost

The AER has not designated any financial assets or liabilities in the fair value category, does not have any significant foreign currency transactions and does not hold any derivative contracts. The AER has no significant remeasurement gains or losses and consequently has not presented a 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 are the AER's financial claims on external organizations and individuals at the year end.

Cash and cash equivalents

Cash comprises cash on hand and demand deposits.

Accounts receivable

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

Notes to the Consolidated Financial Statements

Aberta Energy Regulator
March 31, 2021

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

Basis of Financial Reporting (continued)

Liabilities

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

Bank indebtedness

Bank indebtedness comprises the amount outstanding for a revolving line of credit.

Deferred lease incentives

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

Environmental Liabilities

Liability for Contaminated Sites:

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

A liability for remediation of a contaminated site may arise from an operation that is either in productive use or no longer in productive use and may also arise from an unexpected event resulting in contamination. The resulting liability is recognized net of any expected recoveries, 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

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:

- are normally employed to deliver AER services;
- may be consumed in the normal course of operations; and
- 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

Aberta Energy Regulator
March 31, 2021

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 of the tangible capital assets, excluding land, is amortized over their estimated useful lives as follows:

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

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

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

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

Prepaid expenses

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

Measurement uncertainty

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

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

Note 3 FUTURE CHANGES IN ACCOUNTING STANDARDS

The Public Sector Accounting Board has approved the following accounting standards:

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

This standard provides guidance on how to account for and report liabilities for retirement of tangible capital assets.

PS 3400 Revenue (effective April 1, 2023)

This standard provides guidance on how to account for and report on revenue, and specifically, it differentiates between revenue arising from exchange and non-exchange transactions.

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

Notes to the Consolidated Financial Statements

Aberta Energy Regulator
March 31, 2021

Note 4 BUDGET

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

Note 5 ORPHAN WELL ABANDONMENT

(in thousands)

The Government of Alberta has delegated the authority to manage the abandonment and reclamation of wells, facilities and pipelines that are licensed to defunct licensees to the Orphan Well Association. The AER collects the orphan levy and first time licensee application fees through the Orphan Fund and transfers the funds to the Orphan Well Association. During the year ended March 31, 2021, the AER collected $65,225 (2020 - $60,345) in levies and $473 (2020 - $694) in application fees.

Note 6 CASH AND CASH EQUIVALENTS AND BANK INDEBTEDNESS

(in thousands, unless otherwise noted)

	2021	2020
Cash and cash equivalents	$ 26,226	$ -
Bank indebtedness	-	(812)
	$ 26,226	$ (812)

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, 2021, the AER earned interest at an annual average rate of 0.7% (2020 - 2.1%).

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

Bank advances on the line of credit are payable on demand and bear interest at a rate of prime less 0.75%. For the year ended March 31, 2021, interest expense on the revolving line of credit was $4 (2020 - $143).

Note 7 ACCOUNTS RECEIVABLE

(in thousands)

Accounts receivable are unsecured and non-interest bearing.

	2021			2020
	Gross amount	Allowance for doubtful accounts	Net recoverable value	Net recoverable value
Accounts receivable	$ 3,127	$ (1,671)	$ 1,456	$ 1,920

Note 8 ACCOUNTS PAYABLE AND OTHER ACCRUED LIABILITIES

(in thousands)

	2021	2020
Accrued liabilities	$ 15,722	$ 14,177
Accounts payable	2,315	3,052
Unearned revenue	325	726
	$ 18,362	$ 17,955

Notes to the Consolidated Financial Statements

Aberta Energy Regulator
March 31, 2021

Note 9 FINANCIAL INSTRUMENTS

(in thousands)

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

Financial Risk Management

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

(a) Liquidity risk

Liquidity risk is the risk that the AER will encounter difficulty in meeting obligations associated with its financial liabilities. Liquidity requirements of the AER are met primarily through the collection of funding at the beginning of the year to fund operating expenses and capital expenditures throughout the year. The AER manages liquidity risk by having established budget processes and regularly monitoring cash flows to ensure the necessary funds are on hand to fulfill upcoming obligations. In addition, the AER maintains a revolving line of credit which provides financial flexibility to allow the AER to meet its obligations if funding cannot be collected on a timely basis. As at March 31, 2021, the AER had bank indebtedness of $nil (2020 - $812).

(b) Credit risk

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

Note 10 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.

	2021			2020
	Leasehold improvement costs	Reduced rent benefits and rent-free periods	Total	Total
Balance at beginning of year	$ 12,891	$ 3,058	$ 15,949	$ 17,568
Amortization	(1,252)	(365)	(1,617)	(1,619)
Balance at end of year	$ 11,639	$ 2,693	$ 14,332	$ 15,949

Notes to the Consolidated Financial Statements

Aberta Energy Regulator
March 31, 2021

Note 11 ENVIRONMENTAL LIABILITIES

(in thousands, unless otherwise noted)

The AER has a mandate to protect public safety and the environment. As at March 31, 2021, the AER is not responsible, nor has it accepted responsibility, for performing remediation and reclamation work at contaminated sites. The AER has $nil (2020 - $nil) environmental liabilities recorded.

As at March 31, 2021, the AER is administering 28 (2020 – 28) legacy sites. Of these sites, the AER identified 5 (2020 – 3) sites as having immediate public safety and environmental risk, and the AER needed to take appropriate action to mitigate these risks. During the year ended March 31, 2021, the AER incurred $906 (2020 - $460) 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 not reported.

Note 12 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, 2021, the expense for these pension plans is equal to the contributions of $12,539 (2020 - $15,533) and is included in salaries, wages and employee benefits on Schedule 1. The AER is not responsible for future funding of the plan deficit other than through contribution increases.

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

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

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

Pension plan assets are valued at market values. During the year ended March 31, 2021, the weighted average actual return on plan assets was 14.7% (-3.7% in 2020).

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

Accrued benefit obligations	2021	2020
Discount rate	4.4%	4.8%
Rate of compensation increase	0% until March 31, 2022, 3.0% thereafter	0% until March 31, 2021, 3.5% thereafter
Long-term inflation rate	2.0%	2.0%

Pension benefit costs for the year	2021	2020
Discount rate	4.8%	5.1%
Expected rate of return on plan assets	4.8%	5.1%
Rate of compensation increase	0% until March 31, 2021, 3.5% thereafter	0% until Sep 30, 2019, 3.5% thereafter

Notes to the Consolidated Financial Statements

Aberta Energy Regulator
March 31, 2021

Note 12 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:

	2021	2020
Market value of plan assets	$ 74,119	$ 65,442
Accrued benefit obligations	(70,954)	(72,461)
Plan surplus (deficit)	3,165	(7,019)
Unamortized actuarial losses	1,758	8,524
Pension assets	$ 4,923	$ 1,505

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

	2021	2020
Current period benefit cost	$ 3,976	$ 4,326
Interest cost	3,442	3,382
Expected return on plan assets	(3,039)	(3,574)
Amortization of actuarial losses (gains)	804	(53)
Loss on curtailments [a]	-	1,342
Unamortized gains recognized in curtailments	-	(172)
	$ 5,183	$ 5,251

[a] For the year ended March 31, 2020, the AER underwent a re-organization and decreased the number of employees. This resulted in a curtailment due to a reduced number of active employees in the AER's defined benefit pension plans. The curtailment impact was a $1,342 increase in the accrued benefit obligations recognized through pension expense for the year ended March 31, 2020.

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

	2021	2020
Benefits paid	$ 10,171	$ 5,325
AER contributions	8,600	4,616
Employees' contributions	683	839

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

	2021	2020
Equity securities	48.2%	42.3%
Debt securities	22.2%	24.7%
Alternatives	17.3%	19.6%
Other	12.3%	13.4%
	100.0%	100.0%

Notes to the Consolidated Financial Statements

Aberta Energy Regulator
March 31, 2021

Note 13 TANGIBLE CAPITAL ASSETS

(in thousands)

	2021					2020
	Land	Leasehold improvements	Furniture and equipment	Computer hardware and software	Total	Total
Estimated useful life	Indefinite	Term of the lease	5-12 years	4-5 years		
Historical cost [1]						
Beginning of year	$ 282	$ 45,735	$ 13,112	$ 143,420	$ 202,549	$ 196,874
Additions	-	765	396	12,536	13,697	12,704
Disposals, including write-downs	-	-	(448)	(7,394)	(7,842)	(7,029)
	282	46,500	13,060	148,562	208,404	202,549
Accumulated amortization						
Beginning of year	$ -	$ 20,179	$ 9,427	$ 109,838	$ 139,444	$ 130,459
Amortization expense	-	2,734	905	12,047	15,686	15,947
Effect of disposals, including write-downs	-	-	(426)	(6,433)	(6,859)	(6,962)
	-	22,913	9,906	115,452	148,271	139,444
Net book value at March 31, 2021	$ 282	$ 23,587	$ 3,154	$ 33,110	$ 60,133	
Net book value at March 31, 2020	$ 282	$ 25,556	$ 3,685	$ 33,582		$ 63,105

[1] As at March 31, 2021, historical cost of computer hardware and software includes work-in-progress totalling $6,630 (2020 - $76).

Note 14 ACCUMULATED SURPLUS

(in thousands)

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

	2021			2020
	Investments in tangible capital assets [a]	Unrestricted net assets (debt)	Total	Total
Balance at beginning of year	$ 50,214	$ (9,304)	$ 40,910	$ 66,517
Annual operating surplus (deficit)	-	26,577	26,577	(25,607)
Net investment in capital assets [a]	(1,720)	1,720	-	-
Balance at end of year	$ 48,494	$ 18,993	$ 67,487	$ 40,910

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

Notes to the Consolidated Financial Statements

Aberta Energy Regulator
March 31, 2021

Note 15 CONTINGENT LIABILITIES

(in thousands)

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

Accruals have been made in specific instances where it is likely that losses will be incurred based on a reasonable estimate. As at March 31, 2021, accruals totalling $125 (2020 - $630) have been recognized as a liability.

The AER has identified various sites where contamination exists and the level of contamination is either known or unknown at this time. As at March 31, 2021, no liability has been recognized for these sites as further testing and evaluation is required to determine the extent of immediate actions necessary. No liability for remediation on other sites has been recognized as the AER becoming responsible for these sites is not determinable; the AER does not expect to give up any future economic benefits; no reasonable estimate of the amount can be made; or a combination of these factors. The AER's ongoing efforts to assess contaminated sites may result in environmental liabilities related to newly identified sites, or change in the assessment or intended use of existing sites. Any change to the environmental liabilities will be accrued in the year in which they are assessed as likely and measurable.

Note 16 CONTRACTUAL OBLIGATIONS

(in thousands)

As at March 31, 2021, the AER had contractual obligations totalling $162,248 (2020 - $171,894).

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, 2021, estimated payment requirements for obligations under operating leases and contracts for each of the next five years and thereafter are as follows:

2021-22	$ 43,059
2022-23	29,634
2023-24	17,497
2024-25	11,662
2025-26	10,464
Thereafter	49,932
	$ 162,248

Notes to the Consolidated Financial Statements

Aberta Energy Regulator
March 31, 2021

Note 17 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.

As at March 31, 2021, assets under administration included the following types of security deposits:

	2021	2020	2021	2020
	Cash	Cash	Letters of credit	Letters of credit
Liability Management Rating programs and landfills	$ 90,431	$ 98,812	$ 225,418	$ 220,667
Mine Financial Security program	39,342	39,146	1,447,447	1,434,643
Other programs	10,446	6,834	7,714	7,778
	$ 140,219	$ 144,792	$ 1,680,579	$ 1,663,088

Note 18 COVID-19 IMPACT

On March 11, 2020, the World Health Organization declared the COVID-19 disease to be a global pandemic and on March 17, 2020, the Government of Alberta declared a state of public health emergency. These declarations have impacted the AER in the following ways:

Revenues

On March 20, 2020, the Government of Alberta committed to provide relief for the energy sector by funding the AER's administration fees for the first six months of fiscal 2020-21. The AER received the grant in six monthly installments between April and September 2020 for a total of $113 million.

Operations

The AER maintained core regulatory functions as most staff transitioned to working remotely during the COVID-19 pandemic. The AER's operations were not significantly impacted by COVID-19.

Note 19 COMPARATIVE FIGURES

Certain 2020 figures have been reclassified, where necessary, to conform to the 2021 presentation.

Note 20 APPROVAL OF CONSOLIDATED FINANCIAL STATEMENTS

These consolidated financial statements were approved by the AER Board of Directors on May 13, 2021.

Expenses Detailed by Object

Aberta Energy Regulator
Year Ended March 31, 2021
Schedule 1

	2021	2020
	(in thousands)	
Salaries, wages and employee benefits	$ 131,598	$ 192,271
Buildings	20,354	20,577
Computer services	17,112	17,238
Amortization of tangible capital assets	15,686	15,947
Consulting services	14,634	12,429
Travel and transportation	1,382	1,815
Loss on disposal and write-down of tangible capital assets	983	67
Administrative	915	3,492
Abandonment and enforcement	766	-
Equipment rent and maintenance	323	412
	$ 203,753	$ 264,248

Salary and Benefits Disclosure

Aberta Energy Regulator
Year Ended March 31, 2021
Schedule 2

	2021				2020
	Base salary [(a)]	Other cash benefits [(b)]	Other non-cash benefits [(c)]	Total	Total
			(in thousands)		
Position					
Board of Directors					
Chair [(d)]	$ 131	$ -	$ 7	138	$ 78
Members [(e)]	334	-	20	354	332
Executives					
President and Chief Executive Officer [(f)]	319	30	73	422	-
Chief Hearing Commissioner	218	24	47	289	296
Chief Operations Officer [(g)]	259	17	64	340	148
Executive Vice-President, Law and General Counsel	274	9	60	343	363
Executive Vice-President, Corporate Services [(h,n)]	231	196	77	504	157
Vice-President of Finance and Chief Financial Officer [(i,n)]	130	7	54	191	-
Former President and Chief Executive Officer [(j)]	17	6	-	23	511
Former Executive Vice-President, Operations [(k,n)]	-	-	-	-	394
Executive Vice-President, Strategy & Regulatory [(l,n)]	-	-	-	-	686
Executive Vice-President, Stakeholder & Government Engagement [(m,n)]	-	-	-	-	407

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

(b) Includes payments in lieu of vacation, pension and health benefits, as well as severance, vehicle allowances and other cash reimbursements. There were no bonuses paid in 2021.

(c) Includes contributions to all benefits as applicable, including employer's share of Employment Insurance, Canada Pension Plan, Government of Alberta and AER pension plans, health benefits, and payments made for professional memberships, tuition fees, fair market value of parking and other taxable benefits.

(d) Two individuals occupied the position of Chair during 2021. The current Chair was appointed on April 15, 2020, and is remunerated with a monthly honorarium as per rates prescribed in the Orders in Council. Prior to the current Chair's appointment, the previous Chair's remuneration was set at $nil while this individual occupied the position from September 6, 2019 until April 15, 2020. Prior to the previous Chair, a former Chair occupied the position until September 6, 2019, at which time the individual's appointment was rescinded; the amount in 2020 reflects remuneration paid to the individual until September 6, 2019.

(e) The incumbent Board of Directors consists of six members. Five Board members are remunerated with monthly honoraria as per rates prescribed in the Orders in Council. Remuneration for one Board member is set at $nil. As at March 31, 2020, the Board of Directors consisted of four members. On April 15, 2020, one member resigned and four new members were appointed. On June 5, 2020, one member was rescinded. The 2020 amount reflects four members until April 28, 2019 and three members from April 28, 2019 until September 6, 2019. For the remainder of the 2020 fiscal year, the Board of Directors consisted of four members.

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

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

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

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

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

(k) The incumbent held the position until October 23, 2019, at which time the incumbent was terminated. Severance pay of $171 was expensed in 2020.

(l) The incumbent held the position until October 23, 2019, at which time the incumbent was terminated. The position was eliminated effective October 28, 2019. Severance pay of $449 was expensed in 2020.

(m) The incumbent held the position until October 23, 2019, at which time the incumbent was terminated. The position was eliminated effective October 28, 2019. Severance pay of $168 was expensed in 2020.

Salary and Benefits Disclosure

Aberta Energy Regulator
Year Ended March 31, 2021
Schedule 2 (continued)

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

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 year ended March 31, 2021 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 management pension plans.

	2021			2020
Position	**Current service cost**	**Prior service and other costs**	**Total**	**Total**
Executive Vice-President, Corporate Services	$ 32	$ 2	$ 34	$ 33
Vice-President of Finance and Chief Financial Officer	23	-	23	-
Former Executive Vice-President, Operations (o)	-	-	-	7
Executive Vice-President, Strategy & Regulatory	-	-	-	15
Executive Vice-President, Stakeholder & Government Engagement	-	-	-	28

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

Position	**Accrued obligation April 1, 2020**	**Changes in accrued obligation**	**Accrued obligation March 31, 2021**	**Accrued obligation March 31, 2020**
Executive Vice-President, Corporate Services	$ 128	$ 59	$ 187	$ 128
Vice-President of Finance and Chief Financial Officer	-	25	25	-
Executive Vice-President, Strategy & Regulatory	718	1	719	718
Executive Vice-President, Stakeholder & Government Engagement	16	1	17	16

(o) The pension obligation for the former Executive Vice-President, Operations was paid out during the year ended March 31, 2020.

Consolidated Actual Results Compared with Budget

Aberta Energy Regulator
Year Ended March 31, 2021
Schedule 3

	Budget (Note 4)	Adjustments [a]	Adjusted budget	Actual
	(in thousands)			
Revenues				
Administration fees	$ 226,450	$ (113,000)	$ 113,450	$ 114,240
Government of Alberta grant		113,000	113,000	113,000
Orphan fund levy and fees	69,000	(3,500)	65,500	65,698
Information, services and fees	3,542	(1,703)	1,839	2,731
Investment income	867	-	867	359
	299,859	(5,203)	294,656	296,028
Expenses				
Energy regulation	215,859	(1,703)	214,156	203,753
Orphan well abandonment	69,000	(3,500)	65,500	65,698
	284,859	(5,203)	279,656	269,451
	15,000	-	15,000	26,577
Capital				
Capital investment	14,500	-	14,500	13,697
Less: Amortization of tangible capital assets	(16,000)	-	(16,000)	(15,686)
Loss on disposal and write-down of tangible capital assets		-		(983)
Net capital investment	(1,500)	-	(1,500)	(2,972)
Surplus	$ 16,500	$ -	$ 16,500	$ 29,549

(a) Adjustments reflect a provincial grant announced by the Government of Alberta (GoA), a decrease in revenues collected from information sales, a GoA-mandated in-year savings request, and a GoA request to delay issuing the large facility levy. Adjustments are related to the economic impacts of COVID-19 and low commodity prices.

Related Party Transactions

Aberta Energy Regulator
Year Ended March 31, 2021
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 2021, 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	
	2021	2020	2021	2020
	(in thousands)		(in thousands)	
Revenues				
Government of Alberta grant	$ 113,000	$ -	$ -	$ -
Information, services and fees	366	96	361	618
	$ 113,366	$ 96	$ 361	$ 618

	Entities in the Ministry of Energy		Other entities	
	2021	2020	2021	2020 [(a)]
	(in thousands)		(in thousands)	
Expenses				
Computer services	$ 418	$ 454	$ 2,975	$ 4,270
Buildings	-	-	528	509
Administrative	-	-	396	430
Consulting services	-	-	310	573
	$ 418	$ 454	$ 4,209	$ 5,782
Receivable from	$ 108	$ 119	$ 33	$ 4
Prepaid expenses and other assets	$ -	$ -	$ 36	$ 40
Payable to	$ 209	$ 94	$ 641	$ 724
Unearned revenue	$ 1	$ -	$ -	$ -
Contractual obligations [(a)]	$ -	$ -	$ 7,069	$ 10,390

(a) Certain 2020 amounts have been restated to ensure completeness of 2020 related party transactions.

(b) Contractual obligations are obligations of the AER to related parties that will become liabilities in the future when the terms of those contracts or agreements are met.

Alberta Utilities Commission

Financial Statements

For the year ended March 31, 2021

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Independent Auditor's Report

Auditor General OF ALBERTA

To the Members of the Alberta Utilities Commission

Report on the Financial Statements

Opinion

I have audited the financial statements of the Alberta Utilities Commission (the Commission), which comprise the statement of financial position as at March 31, 2021, and the statements of operations, change in net financial assets, and cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In my opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Commission as at March 31, 2021, and the results of its operations, its changes in net financial assets, and its cash flows for the year then ended in accordance with Canadian public sector accounting standards.

Basis for opinion

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

Other information

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

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

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

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

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

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

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

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

Auditor's responsibilities for the audit of the financial statements

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

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

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

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

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

May 31, 2021
Edmonton, Alberta

Statement of Operations

Alberta Utilities Commission
Year ended March 31, 2021

	2021		2020
	Budget (Schedule 3)	Actual	Actual
	(in thousands)		
Revenues			
Administration fees	$ 32,354	$ 29,971	$ 31,291
Investment income	300	73	309
Professional services and other revenue	100	145	142
	32,754	30,189	31,742
Expenses			
Utility regulation (Schedule 1)	32,554	30,558	32,530
Annual operating surplus (deficit)	200	(369)	(788)
Accumulated surplus, beginning of year	13,271	13,271	14,059
Accumulated surplus, end of year	**$ 13,471**	**$ 12,902**	**$ 13,271**

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

Statement of Financial Position

Alberta Utilities Commission
As at March 31, 2021

	2021	2020
	(in thousands)	
Financial Assets		
Cash and cash equivalents (Note 5)	$ 9,477	$ 8,356
Accounts receivable	94	74
Accrued pension asset (Note 6)	723	585
	10,294	9,015
Liabilities		
Accounts payable and other accrued liabilities (Note 7)	2,181	1,533
Deferred lease incentive (Note 8)	4,798	5,559
	6,979	7,092
Net Financial Assets	3,315	1,923
Non-Financial Assets		
Capital assets (Note 9)	8,576	10,151
Prepaid expenses	1,011	1,197
	9,587	11,348
Net Assets		
Accumulated surplus (Note 10)	$ 12,902	$ 13,271

Contractual obligations (Note 11)

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

Statement of Change in Net Financial Assets

Alberta Utilities Commission
Year Ended March 31, 2021

	2021 Budget (Schedule 3)	2021 Actual	2020 Actual
	-----(in thousands)-----		
Annual operating surplus (deficit)	$ 200	$ (369)	$ (788)
Acquisition of capital assets (Note 9)	(2,000)	(288)	(729)
Amortization of capital assets (Note 9)	1,800	1,858	1,995
Net loss on disposal, writedowns of capital assets		4	4
Proceeds on disposal of capital assets		1	2
Decrease in prepaid expenses		186	49
Increase in net financial assets in the year	-	1,392	533
Net financial assets, beginning of year	1,923	1,923	1,390
Net financial assets, end of year	**$ 1,923**	**$ 3,315**	**$ 1,923**

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

Statement of Cash Flows

Alberta Utilities Commission
Year ended March 31, 2021

	2021	2020
	(in thousands)	
Operating transactions		
Annual operating deficit	$ (369)	$ (788)
Non-cash items included in annual deficit:		
Amortization of capital assets (Note 9)	1,858	1,995
Pension expense	935	662
Net loss on disposal, writedowns of capital assets	4	4
(Increase) decrease in accounts receivable	(20)	297
Decrease in prepaid expenses	186	49
Increase (decrease) in accounts payable and other accrued liabilities	668	(94)
Cash provided by operating transactions	3,262	2,125
Capital transactions		
Acquisition of capital assets (Note 9)	(288)	(729)
Proceeds on disposal of capital assets	1	2
Cash applied to capital transactions	(287)	(727)
Financing transactions		
Pension obligations funded	(1,073)	(902)
Net lease incentives amortized	(761)	(761)
Net lease obligations repaid	(20)	(16)
Cash applied to financing transactions	(1,854)	(1,679)
Increase (decrease) in cash and cash equivalents	1,121	(281)
Cash and cash equivalents, beginning of year	8,356	8,637
Cash and cash equivalents, end of year	**$ 9,477**	**$ 8,356**

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

Notes to the Financial Statements

Alberta Utilities Commission
March 31, 2021
(in thousands of dollars)

Note 1 Authority

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

Note 2 Summary of significant accounting policies and reporting practices

Basis of financial reporting

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

Revenues

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

Expenses

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

Foreign currency translation

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

Valuation of financial assets and liabilities

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

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

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

Notes to the Financial Statements

Alberta Utilities Commission
March 31, 2021
(in thousands of dollars)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Notes to the Financial Statements

Alberta Utilities Commission
March 31, 2021
(in thousands of dollars)

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

Non-financial assets include capital assets and prepaid expenses.

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

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

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

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

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

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

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

Note 3 Future changes in accounting standards

The Public Sector Accounting Board has approved the following accounting standards:

PS 3280 Asset Retirement Obligations (effective April 1, 2022)
This standard provides guidance on how to account for and report liabilities for retirement of tangible capital assets. Management is currently assessing the impact on the financial statements.

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

The AUC has not yet adopted these standards.

Notes to the Financial Statements

Alberta Utilities Commission
March 31, 2021
(in thousands of dollars)

Note 4 Financial instruments

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

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

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

Credit risk
The AUC is not exposed to any significant credit risk from potential non-payment of accounts receivable. As at March 31, 2021, the balance of accounts receivables does not contain amounts that were past due or uncollectible.

Note 5 Cash and cash equivalents

Cash and cash equivalents consist of deposits in the Consolidated Cash Investment Trust Fund which is managed by the Province of Alberta to provide interest income at competitive rates while maintaining appropriate security and liquidity of depositors' capital. The Fund is comprised of high quality short-term and mid-term fixed income securities with a maximum term to maturity of three years. As at March 31, 2021, securities held by the Fund have a time-weighted return of 0.4 per cent per annum (2020: 1.9 per cent).

Note 6 Pension

The AUC participates in the Government of Alberta's multi-employer pension plans of Management Employees Pension Plan, Public Service Pension Plan, and Supplementary Retirement Plan for Public Service Managers. The expense for these pension plans is equal to the contribution of $1,885 for the year ended March 31, 2021 (2020: $2,078). The AUC is not responsible for future funding of the plans deficit other than through contribution increases.

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

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

Pension plan assets are valued at market values. During the year ended March 31, 2021 the weighted average actual return on plan assets was 17.32 per cent (2020: 1.47 per cent).

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

	March 31, 2021	March 31, 2020
Accrued benefit obligations		
Discount rate	3.97%	4.26%
Rate of compensation increase	3.00%	3.50%
Long-term inflation rate	2.00%	2.00%

Notes to the Financial Statements

Alberta Utilities Commission
March 31, 2021
(in thousands of dollars)

Note 6 Pension (continued)

	2021	2020
Pension Benefit costs for the year		
Discount rate	4.26%	4.71%
Expected rate of return on plan assets	4.26%	4.71%
Rate of compensation increase	3.50%	3.50%

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

	March 31, 2021	March 31, 2020
Market value of plan assets	$ 16,309	$ 13,306
Accrued benefit obligations	15,403	14,514
Plan (deficit) surplus	906	(1,208)
Unamortized actuarial loss (gain)	(183)	1,793
Accrued pension asset	$ 723	$ 585

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

	2021	2020
Current period benefit costs	$ 591	$ 643
Interest cost	639	591
Expected return on plan assets	(594)	(610)
Amortization of actuarial losses	299	38
	$ 935	$ 662

The average remaining service period of active employees is 6.2 years (2020: 6.6 years).

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

	2021	2020
AUC contribution	$ 1,073	$ 902
Employees' contribution	181	192
Benefits paid	610	390

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

	March 31, 2021	March 31, 2020
Equity securities	47.70%	43.40%
Debt securities	15.80%	17.59%
Other	36.50%	39.01%
	100.00%	100.00%

Notes to the Financial Statements

Alberta Utilities Commission
March 31, 2021
(in thousands of dollars)

Note 7 Accounts payable and other accrued liabilities

	2021	2020
Accounts payable	$ 334	$ 220
Other accrued liabilities	1,813	1,259
Capital lease obligation	34	54
	$ 2,181	$ 1,533

Note 8 Deferred lease incentive

The AUC has received lease incentives through its office lease agreements. During 2021, the AUC received $0 in lease incentives in the form of cash and free rent (2020: $0).

	2021	2020
Opening balance	$ 5,559	$ 6,320
Cash incentive received	-	-
Rent free period received	-	-
Lease incentive amortized	(761)	(761)
Closing balance	$ 4,798	$ 5,559

Note 9 Capital assets

	March 31, 2021				March 31, 2020
	Furniture and equipment	Computer hardware and software	Leasehold improvement	Total	Total
Historical cost					
Beginning of year	$ 3,093	$ 9,341	$ 6,330	$ 18,764	$ 18,637
Additions	7	281	-	288	729
Disposals	(6)	(396)	(2)	(404)	(602)
	$ 3,094	$ 9,226	$ 6,328	$ 18,648	$ 18,764
Accumulated amortization					
Beginning of year	$ 982	$ 5,994	$ 1,637	$ 8,613	$ 7,214
Amortization expense	332	897	629	1,858	1,995
Effect of disposals	(4)	(395)	-	(399)	(596)
	$ 1,310	$ 6,496	$ 2,266	$ 10,072	$ 8,613
Net book value at March 31, 2021	**$ 1,784**	**$ 2,730**	**$ 4,062**	**$ 8,576**	**$ 10,151**
Net book value at March 31, 2020	**$ 2,111**	**$ 3,347**	**$ 4,693**	**$ 10,151**	

Notes to the Financial Statements

Alberta Utilities Commission
March 31, 2021
(in thousands of dollars)

Note 10 Accumulated surplus

Accumulated surplus is comprised of the following:

	2021			2020
	Investments in capital assets	Unrestricted surplus	Total	Total
Opening balance	$ 10,151	$ 3,120	13,271	$ 14,059
Annual operating deficit	-	(369)	(369)	(788)
Net investment in capital assets	(1,575)	1,575	-	-
Closing balance	$ 8,576	$ 4,326	$ 12,902	$ 13,271

Note 11 Contractual obligations

Contractual obligations are obligations of the AUC to others that will become liabilities in the future when the terms of those contracts or agreements are met. Contractual obligations for each of the next five years and thereafter are as follows:

	Operating leases, contracts and programs	Capital lease principal and interest payments	Total
2022	$ 3,584	$ 1	$ 3,585
2023	2,339	-	2,339
2024	2,438	-	2,438
2025	2,351	-	2,351
2026	2,243	-	2,243
Thereafter	4,529	-	4,529
	$ 17,484	$ 1	$ 17,485

Note 12 Related party transactions

Related parties are those entities consolidated or accounted for on the modified equity basis in the Government of Alberta's Consolidated Financial Statements. For the year ended March 31, 2021 the AUC received and paid $121 (2020: $196) for services from other government of Alberta organizations. The AUC had not received or provided any contributed goods or services from other government of Alberta organizations. Related parties also include key management personnel and close family members of those individuals at the AUC. There were no transactions between the AUC and its key management personnel or close family members during the year.

Note 13 Approval of financial statements

These financial statements were approved by the AUC's Chair's Management Committee.

Expenses - Detailed by Object

Alberta Utilities Commission
Year Ended March 31, 2021
Schedule 1

	2021		2020
	Budget	Actual	Actual
	(in thousands)		
Salaries, wages and employee benefits	$ 24,623	$ 23,147	$ 25,028
Supplies and services	6,131	5,551	5,503
Amortization of capital assets (Note 9)	1,800	1,858	1,995
Loss on disposal of capital assets	-	2	4
	$ 32,554	$ 30,558	$ 32,530

Salary and Benefits Disclosure

Alberta Utilities Commission
Year Ended March 31, 2021
Schedule 2

	2021				2020
	Base Salary [1]	Other Cash Benefits [2]	Other Non-cash Benefits [3]	Total	Total
	(in thousands)				
Chair of the Commission [4]	$ 333	$ 361	$ 69	$ 763	$ 458
Vice-Chair	218	10	54	282	328
Vice-Chair [5]	67	169	4	240	207
Commission Member	196	18	48	262	290
Commission Member	196	17	45	258	252
Commission Member	176	2	47	225	282
Commission Member [6]	108	78	27	213	271
Commission Member [7]	104	77	26	207	268
Commission Member [8]	42	-	13	55	5
Commission Member [9]	-	-	-	-	83

(1) Includes pensionable base pay.

(2) Includes payments in lieu of vacation, health and pension benefits. No bonuses have been paid.

(3) Employer's contributions to all employee benefits including Employment Insurance, Canada Pension Plan, Alberta pension plans, health benefits, professional memberships, tuition fees and fair market value of parking. Automobiles were provided but no dollar amount included in other non-cash benefits.

(4) The position was occupied by two individuals at different times during the year. New Chair was appointed on June 24, 2020. Included in Other Cash Benefits is $296 in severance benefits paid based on employment agreement with Government of Alberta.

(5) The Vice-Chair position became vacant as of July 21, 2020. Included in Other Cash Benefits is $135 in severance benefits paid based on employment agreement with Government of Alberta.

(6) The position was vacant from July 21, 2020 - January 3, 2021. Included in Other Cash Benefits is $45 in severance benefits paid based on employment agreement with Government of Alberta.

(7) The position was vacant from July 21, 2020 - January 3, 2021. Included in Other Cash Benefits is $45 in severance benefits paid based on employment agreement with Government of Alberta.

(8) The position became vacant as of June 24, 2020. The position was vacant from July 23, 2018 to March 24, 2020.

(9) The position became vacant as of August 5, 2019.

Authorized Budget

Alberta Utilities Commission
Year Ended March 31, 2021
Schedule 3

	Budget (Estimate)	Authorized Changes	Authorized Budget	Actual
	-----------------	-(in thousands)-	-----------------	-----------------
Revenues				
Administration fees	$ 32,354	$ (258)	$ 32,096	$ 29,971
Investment income	300	-	300	73
Professional services	100	-	100	145
	32,754	(258)	32,496	30,189
Expenses				
Utility regulation	32,554	(258)	32,296	30,558
Net Capital Investment				
Capital investment	2,000	-	2,000	288
Less:				
Amortization	(1,800)	-	(1,800)	(1,858)
Net Loss on disposal, writedowns of capital assets	-	-	-	(4)
Proceeds on disposal of capital assets	-	-	-	(1)
	200	-	200	(1,575)
	$ -	$ -	$ -	$ 1,206

Note:

The Budget is based on the AUC Business Plan for the year ended March 31, 2021. The Budget and Authorized Changes have been approved by the government of Alberta.

Alberta Petroleum Marketing Commission

Consolidated Financial Statements and Notes

As at March 31, 2021 and December 31, 2019 and

For the fifteen months ended March 31, 2021 and the twelve months ended December 31, 2019

Table of Contents

Auditor General
OF ALBERTA

Independent Auditor's Report

To the Board of Directors of the Alberta Petroleum Marketing Commission

Report on the Consolidated Financial Statements

Opinion

I have audited the consolidated financial statements of the Alberta Petroleum Marketing Commission (the Group), which comprise the consolidated statement of financial position as at March 31, 2021, and the consolidated statements of loss and comprehensive loss, changes in deficiency, and cash flows for the fifteen month period 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, 2021, and its financial performance, and its cash flows for the fifteen month period 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

June 17, 2021
Edmonton, Alberta

Consolidated Statement of Financial Position

Alberta Petroleum Marketing Commission
(thousands of Canadian dollars)

As at	Note		March 31, 2021		December 31, 2019
			Note 2(b)		Note 2(e)
ASSETS					
Current assets					
Cash and cash equivalents	5	$	195,180	$	13,415
Cash held in trust	6		11,282		-
Accounts receivable	7		401,978		83,996
Inventory	8		51,711		-
Term loan receivable	11		39,776		-
			699,927		**97,411**
Non current assets					
Inventory	8		6,877		-
Intangible assets	9		8,781		10,112
Investment in KXL Expansion Project	10		106,000		-
Term loan receivable	11		499,577		652,209
		$	**1,321,162**	**$**	**759,732**
LIABILITIES					
Current liabilities					
Accounts payable	12	$	475,952	$	36,184
Due to the Department of Energy	13		58,642		84,586
KXL Expansion Project Debt Guarantee	14		1,035,002		-
Short term debt	15		1,896,639		855,043
Accrued interest on short term debt	15		3,001		7,915
Sturgeon Refinery Processing Agreement provision	16		550,000		143,743
			4,019,236		**1,127,471**
Non current liabilities					
Sturgeon Refinery Processing Agreement provision	16		1,944,000		1,583,257
			5,963,236		**2,710,728**
DEFICIENCY			(4,642,074)		(1,950,996)
		$	**1,321,162**	**$**	**759,732**

Commitments (Note 19)

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

Consolidated Statement of Loss and Comprehensive Loss

Alberta Petroleum Marketing Commission
(thousands of Canadian dollars)

	Note	For Fifteen Months Ended March 31, 2021	For Twelve Months Ended December 31, 2019
		Note 2(b)	Note 2(e)
Revenues			
Refinery sales		$ 1,131,367	$ -
Marketing fee income		5,256	6,747
		1,136,623	6,747
Finance income		55,703	61,726
		1,192,326	**68,473**
Expenses			
Refinery feedstock purchases		909,227	-
Refinery tolls		837,150	201,011
General and administrative expenses	23	18,940	6,621
Amortization		1,331	532
Finance expense		179,983	14,805
Foreign exchange loss		36,825	-
Provisions for Sturgeon Refinery	16, 17	603,916	1,727,025
Loss allowance for KXL Expansion Project Debt Guarantee	14	1,035,002	-
Fair value loss on investment in KXL Expansion Project	10	255,831	-
		3,878,205	**1,949,994**
Loss before income taxes		(2,685,879)	(1,881,521)
Income taxes	18	5,199	-
Net loss and comprehensive loss		**$ (2,691,078)**	**$ (1,881,521)**

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

Consolidated Statement of Changes in Deficiency

Alberta Petroleum Marketing Commission
For the fifteen months ended March 31, 2021 and twelve months ended December 31, 2019
(thousands of Canadian dollars)

Deficiency, January 1, 2019	$	(69,475)
Net loss and comprehensive loss for the year		(1,881,521)
Deficiency, December 31, 2019		**(1,950,996)**
Net loss and comprehensive loss for the period		(2,691,078)
Deficiency, March 31, 2021	**$**	**(4,642,074)**

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

Consolidated Statement of Cash Flows

Alberta Petroleum Marketing Commission
(thousands of Canadian dollars)

	Note	For Fifteen Months Ended March 31, 2021	For Twelve Months Ended December 31, 2019
Operating activities			
Net loss and comprehensive loss		$ (2,691,078)	$ (1,881,521)
Non cash items included in net loss			
Accrued interest on term loan	11	(55,275)	(61,552)
Accrued interest on short term debt		16,393	14,805
Amortization of intangible assets	9	1,331	532
Fair value loss on investment in KXL Expansion Project	10	255,831	-
Foreign exchange loss	10	42,512	-
Change to loss provision for accounts receivable	17	28	67
Change to loss provision for term loan receivable	17	280	25
Change to loss provision for accounts receivable - Sturgeon Refinery	17	226	-
Change to loss provision for Sturgeon Refinery Processing Agreement	16	603,410	1,727,000
Accretion expense for Sturgeon Refinery Processing Agreement	16	163,590	-
Change in loss allowance for KXL Expansion Project Debt Guarantee	14	1,035,002	-
Change to long term inventory	8	(6,877)	-
Interest received from term loan receivable		43,772	-
Interest paid on short term debt		(21,307)	(12,490)
Changes in non-cash working capital	24	32,595	2,538
Net cash used in operating activities		**(579,567)**	**(210,596)**
Investing activities			
Funds from term loan receivable	11	124,079	-
Investment in KXL Expansion Project	10	(1,036,124)	-
TCPL repurchase of KXL Expansion Project - US Class A Interests	10	631,781	-
Intangible assets under development		-	(826)
Net cash used in investing activities		**(280,264)**	**(826)**
Financing activities			
Proceeds from short term debt	15	1,703,236	219,112
Repayment of short term debt	15	(661,640)	-
Net cash from financing activities		**1,041,596**	**219,112**
Increase in cash and cash equivalents		181,765	7,690
Cash and cash equivalents, beginning of period		13,415	5,725
Cash and cash equivalents, end of period		**$ 195,180**	**$ 13,415**
Cash paid			
Interest received		$ 44,200	$ 174
Interest paid		21,307	12,490
Taxes		825	-

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

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission
For the fifteen months ended March 31, 2021 and twelve months ended December 31, 2019
(in thousands of Canadian dollars unless otherwise stated)

Note 1 Authority and structure

The Alberta Petroleum Marketing Commission ("APMC" or the "Commission") operates under the authority of the *Petroleum Marketing Act, Chapter P-10*, Revised Statutes of Alberta 2000, and the *Natural Gas Marketing Act*, Chapter N-1, Revised Statutes of Alberta 2000. Pursuant to Alberta legislation the Commission as agent of Her Majesty the Queen in right of Alberta (the "Province"), as represented by the Department of Energy ("DOE"), accepts delivery of and markets the Province's royalty share of crude oil. This is achieved through the Commission receiving crude oil in kind from producers on behalf of the DOE and transferring the proceeds received from the sale of the crude oil back to the DOE. These consolidated financial statements disclose the transactions the Commission incurs while acting as agent on behalf of the DOE.

The *Petroleum Marketing Act* was amended on January 10, 2014. The amendments provided the Minister of Energy with new power to give directions to APMC; modernized and improved the basic corporate rules under which APMC operates including the ability to appoint up to seven directors, some of whom may be from outside the public service; clarified financial tools available to APMC and ensured proper Crown controls on use of these tools.

The Commission's mandate has been enhanced to include assisting in the development of new energy markets and transportation infrastructure. In line with that is the Commission's involvement with North West Redwater Partnership ("NWRP") and the Sturgeon Refinery. In 2020, APMC through newly created subsidiaries, committed to provide financial support for the construction of the KXL Expansion Pipeline ("KXL Expansion Project").

The Commission operates a Business Development group to identify and analyze business ideas and proposals that provide strategic value to Alberta and are financially feasible.

As an agent of the Government of Alberta ("GOA"), the Commission is not subject to Canadian federal or provincial corporate income taxes.

The Commission is located at the following address: #300, 801 – 6th Avenue S.W., Calgary, Alberta, T2P 3W2. These consolidated financial statements were authorized for issue by the Board of Directors on June 17, 2021.

Note 2 Basis of preparation

(a) Basis of presentation and Statement of Compliance

These consolidated financial statements have been prepared in compliance with International Financial Reporting Standards (IFRS) as published by the International Accounting Standards Board (IASB) and related interpretations as issued by the IFRS Interpretations Committee (IFRIC).

A summary of the results for the Commission's current business operating segments is found in Note 22.

(b) Change in reporting period

The Lieutenant Governor in Council prescribed a change in year end for the Commission from December 31 to March 31 under an Order in Council (O.C. 052/2021). These consolidated financial statements present the Commission's financial position as at March 31, 2021 and the results of its operations and changes in its financial position for the fifteen month period then ended. Comparative information presented in these consolidated financial statements is for the twelve month fiscal year which ended December 31, 2019. As such, amounts in the consolidated financial statements are not entirely comparable.

(c) Basis of measurement

The consolidated financial statements have been prepared on the historical cost basis, except as disclosed in the significant accounting policies in Note 3.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission
For the fifteen months ended March 31, 2021 and twelve months ended December 31, 2019
(in thousands of Canadian dollars unless otherwise stated)

(d) Financial and presentation currency

These consolidated financial statements are presented in Canadian dollars, which is the Commission's functional currency.

(e) Comparative figures

Certain comparative figures have been reclassified to conform to the current period's presentation of a classified balance sheet. As a result, comparative balances for cash and cash equivalents, accounts receivable have been reflected as current assets and accounts payable, due to the Department of Energy, short term debt and accrued interest have been classified as current liabilities. In addition, comparative balances for intangible assets and the term loan receivable have been reflected as non-current assets and the Sturgeon Refinery Processing Agreement provision has been separated between current and long term portion. As well, the presentation of the comparative period for the Consolidated Statement of Loss and Comprehensive Loss has been restated to combine the results of the Commission's operating segments, namely the conventional crude oil and marketing operations and the Sturgeon Refinery, and present the results of those segments in Note 22.

Note 3 Significant accounting policies

The accounting policies set out below have been applied consistently to all periods presented in these consolidated financial statements.

(a) Principles of consolidation

The consolidated financial statements comprise the financial statements of APMC and its subsidiaries. Subsidiaries are all entities over which APMC has control. Subsidiaries are consolidated from the date of acquisition of control and continue to be consolidated until the date that there is loss of control. All intercompany transactions, balances, and unrealized gains and losses from intercompany transactions are eliminated on consolidation. The subsidiaries are detailed below.

Name	Principal activities	Country of Incorporation	% Equity Interest
2254737 Alberta Ltd.	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.	Facilitate APMC's financial support for the project costs related to the Canadian portion of the KXL Expansion Project	Canada	100%
2254753 Alberta Ltd.	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.	Facilitate APMC's financial support for the project costs related to the US portion of the KXL Expansion Project	Canada	100%

2254746 Alberta Ltd is the sole shareholder of:

Name	Principal activities	Country of Incorporation	% Equity Interest
2254746 Alberta Sub Ltd.	Facilitate APMC's financial support for the project costs related to the US portion of the KXL Expansion Project	United States	100%

Notes to the Consolidated Financial Statements

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All of the above subsidiaries have a December 31st year end for statutory purposes, but their results are consolidated through the fifteen month period ended March 31, 2021.

(b) Associates and joint operations

An associate is an entity over which the Commission has significant influence. Significant influence is the power to participate in the financial and operating policy decisions of the investee, but is not control or joint control over those policies.

A joint operation is a type of joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets and obligations for the liabilities of the arrangement. Joint control is the contractually agreed sharing of control of an arrangement.

The considerations made in determining significant influence or joint control are similar to those necessary to determine control over subsidiaries.

Associates in which APMC has an equity interest are accounted for using the equity method. Associates in which APMC does not have an equity interest are not accounted for within these consolidated financial statements, but disclosure with respect to such entities is provided in accordance with IFRS requirements.

Where APMC has an interest in a joint operation, it recognizes, in relation to its proportionate interest, its share of the assets, liabilities, revenue and expenses.

(c) Foreign currencies

The Commission's consolidated financial statements are presented in Canadian dollars, which is also the functional and presentation currency of its subsidiaries.

Transactions in foreign currencies are measured at the functional currency at foreign exchange rates that approximates those on the date of the transaction.

Monetary assets and liabilities and investments denominated in foreign currencies are translated to the appropriate functional currency at the closing rate of exchange at the reporting date.

Differences arising on settlement or translation of monetary items are recognized in profit or loss.

Non-monetary items 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) 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.

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The Commission's business model for managing financial assets refers to how it manages its financial assets in order to generate cash flows. The business model determines whether cash flows will result from collecting contractual cash flows, selling the financial assets, or both. Financial assets classified and measured at amortized cost are held within a business model with the objective to hold financial assets in order to collect contractual cash flows while financial assets classified and measured at FVTOCI are held within a business model with the objective of both holding to collect contractual cash flows and selling.

Subsequent measurement of financial instruments is based on their initial classifications. The Commission does not currently have any financial assets classified or measured at FVTOCI.

Financial assets at amortized cost:

The Commission classifies cash and cash equivalents, cash held in trust, accounts receivable, and term loan 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 profit or loss when the asset is derecognized, modified or impaired.

Financial assets at FVTPL:

The Commission has determined that it does not have control, joint control or significant influence over its Investment in the KXL Expansion Project Class A and C Interests and this investment does not meet the SPPI test, despite the Class A Interests earning a return in the form of accretion (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 profit and loss.

Derivative financial instruments:

The Commission utilizes financial derivatives to manage foreign exchange exposures. The Commission does not enter into derivative financial instruments for trading or speculative purposes. The Commission has not designated its financial derivative contracts as effective accounting hedges, and thus has not applied hedge accounting, even though the Commission considers all foreign exchange contracts to be economic hedges. As a result, financial derivatives are classified as FVTPL and are recorded on the balance sheet at fair value, with fair value changes recorded in profit or loss.

Impairment:

The Commission's accounting policy for impairment of financial assets is as follows: at each reporting date, on a forward looking basis, the Commission assesses the expected losses associated with its financial assets carried at amortized cost. For trade accounts receivable, the simplified approach permitted by IFRS 9 is applied, which requires expected lifetime credit losses to be recognized from initial recognition of the receivable. To measure expected credit losses, accounts receivable are grouped based on the counterparty investment rating as reported by the credit rating agencies and an anticipated default rate is applied to each rating multiplied by the receivable balance outstanding at a reporting date. For counterparties not rated by the credit rating agencies, the simplified approach and a provision matrix will be used to calculate the impairment provision. The matrix would look at a different percentage applied against each aging category, including the current amounts. The internal and external credit rating of a counterparty will be considered as part of this overall process.

Credit risk for longer term receivables is assessed based on an external credit rating of the counterparty. For longer term receivables with credit risk that has not increased significantly since the date of recognition, the Company measures the expected credit loss as the 12 month expected credit loss. For the NWRP term loan

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receivable, the Commission measures expected credit losses using the default rates for the GOA and Canadian Natural Resources Limited (CNRL) weighted credit ratings.

Changes in the provision for expected credit loss 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, short term debt, and accrued interest on short term debt.

For purposes of subsequent measurement, financial liabilities are classified in two categories:

- Financial liabilities at FVTPL
- Financial liabilities at amortized cost

All of the Commission's financial liabilities are subsequently measured at amortized cost using the EIR method. Gains and losses are recognized in profit or loss when the liabilities are derecognized as well as through the EIR amortization process.

(iii) Fair value measurement:

The Commission measures financial instruments such as the Investment in the KXL Expansion Project at fair value at each Consolidated Statement of Financial Position date.

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place either:

- In the principal market for the asset or liability; or
- In the absence of a principal market, in the most advantageous market for the asset or liability.

The principal or the most advantageous market must be accessible by the Commission. The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest.

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.

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The Commission uses valuation techniques that are appropriate in the circumstances and for which sufficient data are available to measure fair value, maximizing the use of relevant observable inputs and minimizing the use of unobservable inputs.

All assets and liabilities for which fair value is measured or disclosed in the consolidated financial statements are categorized within the fair value hierarchy, described as follows, based on the lowest level input that is significant to the fair value measurement as a whole:

Level 1 – Quoted (unadjusted) market prices in active markets for identical assets or liabilities.
Level 2 – Valuation techniques for which the lowest level input that is significant to the fair value measurement is directly or indirectly observable.
Level 3 – Valuation techniques for which the lowest level input that is significant to the fair value measurement is unobservable.

For assets and liabilities that are recognized in the consolidated 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 after discussion with and approval by the Commission's Board of Directors. 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 developed key assumptions based on objective observable data, to the extent possible, and agrees major inputs to contracts and other relevant documents.

The Commission compares the key assumptions and major input used in the determination of the fair value of each asset and liabilities to relevant external sources when available.

At each reporting period, the Commission presents the valuation results to the Board. This includes a discussion of the major assumptions used in the valuations.

For the purpose of fair value disclosures, the Commission has determined classes of assets and liabilities on the basis of the nature, characteristics and risks of the asset or liability and the level of the fair value hierarchy, as explained above.

(iv) Financial guarantee contracts:

Financial guarantee contracts are contracts issued by APMC that contingently require the Commission to make specified payments to reimburse the holder for a loss it incurs because the specified debtor fails to make payment when due in accordance with the terms of a debt instrument. The date the Commission becomes a party to the irrevocable commitment is the date of initial recognition. Financial guarantee contracts are initially recognized and measured at the fair value of the obligation undertaken in issuing the guarantee, which is generally equal to the guarantee fee received in advance (if any), adjusted for transaction costs that are directly attributable to the issuance of the guarantee. Subsequently, the guarantee is recognized as a liability measured at the higher of (i) the amount initially recognized (if any) less amortization for the passage of time and (ii) the loss allowance measured using an expected credit loss ("ECL") model.

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ECLs with respect to financial guarantee contracts are calculated using a probability of default approach and are based on the difference between the contractual cash flows due in accordance with the contract and all the cash flows that the Commission expects to receive in respect of entitlement to contractual recoveries or reimbursements (but excluding expected guarantee fees or premiums), discounted at an approximation of the current rate representing the risk of cash flows.

ECLs are recognized in two stages. For credit exposures for which there has not been a significant increase in credit risk since initial recognition, ECLs are provided for credit losses that result from default events that are possible within the next 12 months (a 12-month ECL). For those credit exposures for which there has been a significant increase in credit risk since initial recognition, a loss allowance is required for credit losses expected over the remaining life of the exposure, irrespective of the timing of the default (a lifetime ECL). Any changes in the recognized liability is included in income. In assessing whether there has been a significant increase in the credit risk since initial recognition, the Commission considers the changes in the risk that the specified debtor will default on the contract.

(e) Inventory

Inventory is comprised of blended feedstock, intermediates and products. Products include ultra-low sulphur diesel, diluent, unconverted oil, liquefied petroleum gas, and sulphur. Inventories are carried at the lower of cost and net realizable value. APMC contracts with third parties to directly deliver the Crown Supply of feedstock to the refinery. The cost of the Crown Supply to APMC 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 price. If the carrying amount exceeds net realizable value, a write-down is recognized.

As part of the marketing activities, inventory of $572 is being held in a fiduciary capacity on behalf of the DOE (2019 - $1,152). Inventory represents the royalty oil in feeder and trunk pipelines and consists of both purchased oil and royalty share oil. The Commission purchases oil to fulfill pipeline and quality requirements as part of the conventional crude oil marketing activities. As the Commission does not hold title to the oil and will not benefit from the ultimate sale as a principal, this inventory is not recognized.

(f) Intangible 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. Both systems became operational in July 2019.

The Intangible 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.

(g) Impairment of intangible assets

Intangible 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

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that would have existed if the impairment had not occurred. Therefore, reversal of the loss cannot exceed the total carrying cost less amortization of the asset had the impairment not occurred. The impairment loss reversals are recognized in the Consolidated Statement of Loss and Comprehensive Loss.

(h) Onerous contract provisions

Provisions are recognized when the Commission has a present legal or constructive obligation as a result of past events, it is probable that an outflow of resources will be required to settle the obligation, and the amount has been reliably estimated. Provisions are not recognized for future operating losses. Provisions are measured at the present value of the expenditures expected to be required to settle the obligation using a rate that reflects current market assessments of the time value of money and the risks specific to the obligation. The increase in the provision due to passage of time is recognized as interest expense.

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. This provision would be 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 the updated net present value.

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 income statement. If the net present value turns positive then the reversal of the provision on the balance sheet is to zero (i.e. the contract cannot become an asset).

(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 fees, the Commission's accounting policy for Revenue is as follows. The Commission earns revenue through marketing fees charged to the DOE based on net volumes sold. 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 is lifted from the Refinery facility and control passes to the customer. The customers are assessed for creditworthiness both 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) Finance income and finance expenses

Finance income generated from conventional crude oil marketing operations comprises interest income earned on cash and cash equivalents.

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

Finance expenses consist of interest expense on short term debt obligations due to the Province of Alberta (Note 15) and accretion expense on provisions (Note 16).

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(k) Income taxes

As noted above, the Commission is exempted from Canadian federal and provincial corporate income taxes. However, 2254746 Alberta Sub Ltd., a Delaware incorporated company and 2254746 Alberta Ltd., an Alberta incorporated company have exposure to US federal and state corporate income taxes.

Current income tax
Current income tax assets and liabilities are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted or substantively enacted at the reporting date in the country in which the Company generates taxable income.

Current income tax relating to items recognized directly in equity is recognized in equity and not in profit or loss. Management periodically evaluates positions taken in the tax returns with respect to situations in which applicable tax regulations are subject to interpretation and establishes provisions where appropriate.

Deferred tax

Deferred tax is accounted for using the liability method on temporary differences between the tax basis of assets and liabilities and their carrying value for financial reporting purposes as at the reporting date.

Deferred tax assets are recognized for all deductible temporary differences, the carry forward of unused tax credits, and any unused tax losses. Deferred tax assets are recognized to the extent that it is probable that taxable income will be available against which the deductible temporary differences, the carry forward of unused tax credits, or the unused tax losses can be utilized.

Deferred tax is not recognized for:

- Temporary differences on the initial recognition of assets or liabilities in a transaction that is not a business combination and that affects neither the accounting nor taxable profit or loss;
- Taxable temporary differences arising on the initial recognition of goodwill; and
- Temporary differences related to investments in subsidiaries and joint ventures to the extent that is probable that they will not reverse in the foreseeable future.

The carrying amount of deferred tax assets is reviewed at each reporting date and reduced to the extent that it is no longer probable that taxable income will be available to allow all or part of the deferred tax asset to be utilized. Unrecognized deferred tax assets are re-assessed at each reporting date and are recognized to the extent that it has become probable that future taxable income will allow the deferred tax asset to be recovered.

Deferred tax liabilities are recorded for all temporary differences other than where the temporary difference arises from the initial recognition of goodwill.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the year when the asset is realized or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the reporting date.

Deferred tax assets and deferred tax liabilities are offset if a legally enforceable right exists to set off current tax assets against current tax liabilities and the deferred taxes relate to the same taxable entity and the same taxation authority.

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(l) Accounting Standards Issued But Not Yet Adopted

Onerous Contracts – Costs of Fulfilling a Contract – Amendments to IAS 37

In May 2020, the IASB issued amendments to IAS 37 to specify which costs an entity needs to include when assessing whether a contract is onerous or loss-making.

The amendments apply a "directly related cost approach". The costs that relate directly to a contract to provide goods or services include both incremental costs and an allocation of costs directly related to contract activities. General and administrative costs do not relate directly to a contract and are excluded unless they are explicitly chargeable to the counterparty under the contract.

The amendments are effective for annual reporting periods beginning on or after January 1, 2022. The Commission will apply these amendments to contracts for which it has not yet fulfilled all its obligations at the beginning of the annual reporting period in which it first applies the amendments. The Commission does not currently anticipate any significant impact from these amendments on the consolidated financial statements as a result of the initial application.

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

In January 2020, the IASB issued amendments to paragraphs 69 to 76 of IAS 1 to specify the requirements for classifying liabilities as current or non-current, depending on the existence of the substantive right at the end of the reporting period for an entity to defer settlement of the liability for at least twelve months after the reporting period.

The amendments are effective for annual reporting periods beginning on or after January 1, 2023 and with early adoption permitted. These amendments must be applied retrospectively. The Commission is currently assessing the impact the amendments will have on current practice.

Note 4 Critical accounting estimates and judgments

The preparation of these consolidated financial statements in conformity with IFRS requires the Commission to make judgments, estimates and assumptions that affect the reported amounts of assets, liabilities, and the disclosure of contingencies, if any, at the date of the consolidated financial statements and reported amounts of revenues and expenses during the period. Estimates are subject to measurement uncertainty and changes in such estimates in future years could require a material change in the consolidated financial statements. Estimates and judgements are continuously evaluated and based on the Commission's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Actual results may differ from these estimates. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future period affected.

In March 2020, the global outbreak of the COVID-19 negatively impacted the worldwide demand for crude oil driving down commodity prices. The crude oil price collapse was exacerbated by the inability of the OPEC+ countries to agree on crude oil supply reductions. The COVID-19 pandemic has caused a material disruption to global business and a slowdown of the global economy. While there has been some improvement with world economies starting to open up, the situation is dynamic, and the ongoing economic impact and duration of these events continue to remain uncertain. Estimates and judgement made by the Commission in the preparation of the consolidated financial statements are increasingly difficult and subject to a higher degree of measurement uncertainty during this volatile period.

The following are judgements, estimates and assumptions that the Commission has made in the process of applying APMC's accounting policies and that have the most significant effect on the amounts recognized in these consolidated financial statements.

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(a) Government business enterprise

Under public sector accounting standards, organizations which are controlled by the government are either government business enterprises or other government organizations. Government business enterprises are required to apply IFRS, whereas other government organizations are provided with a choice for basis of presentation. The Commission has exercised judgment and determined that it is a government business enterprise because it is a separate legal entity and has been delegated financial and operational authority to carry on a business. In 2013, the Commission's mandate was expanded, and it is expected through its involvement with other marketing activities, such as the Sturgeon Refinery and KXL Expansion Project that it can provide services, maintain its operations and meet liabilities from sources outside of the government reporting entity. Had the Commission not been determined to be a government business enterprise, the Commission would have continued to apply public sector accounting standards, and such an alternative basis of accounting could have a pervasive effect on the measurement and presentation of items in the consolidated financial statements.

(b) Revenue recognition

The Commission has exercised judgment in determining whether it is acting as a principal or agent with respect to conventional crude oil marketing activities. The Commission is providing services to the Crown as delegated in the *Petroleum Marketing Act* that are *"…in the public interest of Alberta"*. The Commission accepts delivery of and markets the Crown's royalty share of crude oil, and has the ability to determine which customers to transact with, and whether it should purchase additional product for blending activities to change the composition of crude oil sold. The Crown has delegated, through the *Petroleum Marketing Act* the responsibilities to the Commission for ensuring the crude oil meets the customers' specifications and establishing prices of the crude oil. However, the Commission is not exposed to inventory risk, this risk belongs to the Crown. Therefore, the gross inflows and economic benefits of conventional crude oil marketing activities are considered collected on behalf of the DOE and are not recognized as revenue.

APMC has used judgment in determining whether it is acting as a principal or agent with respect to crude-by-rail activities. APMC was directed, on May 24, 2019, "…take all steps possible to explore best options for assigning crude-by-rail program contracts entered into by the Commission to third parties, and to enter into assignment agreements as expeditiously as possible with third parties on commercial terms, provided that the final terms have been approved by the Government". While the Commission entered into the contracts, it was acting as agent on behalf of the Crown and all financial risk belongs to the Crown. Therefore, the gross inflows and economic benefits of the crude-by-rail program are considered collected on behalf of the Crown and are not recognized as revenue.

APMC has also exercised judgment in determining whether it is acting as a principal or agent with respect to Sturgeon Refinery activities. As part of the processing agreement, NWRP processes the feedstock provided by the toll payers, APMC and CNRL, into refined products and will sell the refined products and by-products on behalf of APMC and CNRL. APMC and CNRL take the financial responsibility for the refined products and by-products meeting customer specifications, inventory risk, and establishing prices for the products. Therefore, APMC is acting as the principal in this arrangement and the gross inflows and economic benefits of the Sturgeon Refinery activities are recognized as revenue.

(c) Interests in Sturgeon Refinery

NWRP is a general partnership formed by CNR (Redwater) Limited (formerly Canadian Natural Upgrading Limited), a wholly-owned subsidiary of CNRL and by NWU LP, an indirect wholly-owned subsidiary of North West Refining Inc. NWRP was formed under the Partnership Act (Alberta) pursuant to a partnership agreement dated February 15, 2011, as amended on November 7, 2012, March 11, 2013 and April 7, 2014. The partners each have a 50% partnership interest in NWRP.

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The Commission has exercised judgment in determining that it has significant influence over NWRP. As the Commission has no equity ownership interest in NWRP, it will not equity account for the NWRP within these consolidated financial statements. A summary of NWRP's financial information is included in Note 11.

NWRP has entered into various agreements to construct and operate the Sturgeon Refinery, a facility 45 kilometres north-east of Edmonton which has the capacity to process approximately 50,000 barrels per day (bbl/d) of bitumen at an incurred facility capital cost ("FCC") of $10.0 billion (2019 – $10.1 billion). APMC is providing the Sturgeon Refinery with 37,500 bbl/d of bitumen feedstock and Canadian Natural Resources Partnership will provide the remaining 12,500 bbl/d of bitumen feedstock under 30 year cost-for-service tolling agreements (collectively, the Processing Agreements). The Sturgeon Refinery achieved COD on June 1, 2020.

APMC has entered into a term loan with NWRP which earns interest at a rate of prime plus six percent, compounded monthly, and will be repaid over 10 years starting one year after COD. While the loan to NWRP is outstanding, APMC is entitled to a 25 percent voting interest on the Executive Leadership Committee (ELC), which is charged with overseeing and making decisions on the operations of the Sturgeon Refinery. CNRL and North West Refining Inc. have 50 and 25 percent voting interests on the ELC, respectively.

Pursuant to the Processing Agreements, NWRP processes bitumen and sells the refined products on behalf of APMC and CNRL (collectively, the Toll Payers). 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 Toll Payers and NWRP. APMC has exercised judgment in determining that IPTA is a joint operation in which the Commission has a 75% interest in the assets, liabilities, revenue and expenses.

(d) NWRP - Monthly toll commitment

The Commission has used judgment to estimate the toll commitments included in Note 19 Commitments. The components of the toll are: senior debt; operating costs; class A subordinated debt; equity; and incentive fees. To calculate the toll, management has used estimates for factors including future interest rates, operating costs, oil prices (WTI and light/heavy differentials), refined product prices, gas prices and foreign exchange rates.

(e) Sturgeon Refinery Processing Agreement assessment

The Commission uses a cash flow model to determine if the unavoidable costs of meeting the obligations under the NWRP Processing Agreement exceed the economic benefits expected to be received. The model uses a number of variables to calculate a discounted net cash flow 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, discount rates; and operating performance compared to capacity.

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 Processing Agreement has a term of 30 years and may be renewed for successive five year periods at APMC's option. In order to perform the onerous contract analysis, APMC management developed estimates for the key variables based primarily on GOA forecasts.

Based on the analysis, as at the authorization date of these consolidated financial statements, APMC determined the agreement continues to have a negative net present value and a provision is required. See Note 16 for further details.

For each subsequent year-end, the Commission will perform this Processing agreement assessment to determine the updated net present value. 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 income statement. If the net present value turns positive then the reversal of the provision on the balance sheet is to zero (i.e. the contract cannot become an asset).

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(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 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, 2021 using a probability-weighted valuation technique. The fair value of the KXL Investment is included in Level 3 of the fair value hierarchy (see Note 10) 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 22.

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Note 5 Cash and cash equivalents

Cash and cash equivalents as at March 31, 2021 was $195,180 (2019 - $13,415). Cash and cash equivalents consist of deposits in the Consolidated Cash Investment Trust Fund (the “Fund”) which is managed by Alberta Investment Management Corporation to provide competitive interest income while maintaining appropriate security and liquidity of depositors’ capital. The Fund is comprised of high quality short-term fixed income securities with a maximum term to maturity of one year. For the fifteen months ended March 31, 2021, the Commission earned $428 (2019 - $174) with a rate of return of 0.29% per annum (2019 – 1.82% per annum). Due to the nature of Fund investments, the carrying value approximates fair value.

Note 6 Cash held in trust

Cash held in trust as at March 31, 2021 was $11,282 (2019 – nil) and is for the Sturgeon Refinery. It is restricted and held on behalf of the Sturgeon Refinery Toll payers, namely APMC and CNRL. The amount reported is the portion attributable to APMC. 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.

Note 7 Accounts receivable

	March 31, 2021	December 31, 2019
Accounts receivable	$ 402,452	$ 84,216
Credit loss provision	(474)	(220)
Net accounts receivable	$ 401,978	$ 83,996

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

As at March 31, 2021, there was $52,981 (2019 – $84,216) of accounts receivable for marketing transaction activities primarily for the March 2021 delivery month, which will be cash settled on April 25, 2021. In addition, there was $349,471 (2019 – nil) of account receivables from the Sturgeon Refinery consisting primarily of sale of refined products delivered in March 2021. The terms related to the sale of refined products are not greater than net 21 days.

Note 8 Inventory

Current	March 31, 2021	December 31, 2019
Balance, beginning of period	$ -	$ -
Additions	828,817	-
Cost of sales	(777,106)	-
Balance, end of period	$ 51,711	$ -
Long term		
Balance, beginning of period	$ -	$ -
Additions	6,877	-
Balance, end of period	$ 6,877	$ -

Inventory is comprised of blended feedstock, intermediates and products and is carried at the lower of cost and net realizable value. Inventory is classified as short-term if it is expected to be sold within the next twelve months of the financial reporting period.

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Long term inventory consists of line fill and tank bottoms which the Commission does not anticipate selling these volumes in the next 12 months.

The Commission has completed its review of inventory and determined the net realizable value is greater than the carrying value, hence no write-down is required.

Note 9 Intangible assets

Intangible assets		March 31, 2021		December 31, 2019
Balance, beginning of period	$	10,644	$	-
Transfer from Intangible assets under development		-		10,644
Balance, end of period	$	10,644	$	10,644
Accumulated amortization				
Balance, beginning of period	$	(532)	$	-
Amortization		(1,331)		(532)
Balance, end of period	$	(1,863)	$	(532)
Net intangible assets, end of period	$	8,781	$	10,112

The Commission internally developed operations software to handle actualization and settlement of royalty and marketing transactions. In addition, APMC purchased accounting software for reporting and financial settlement of transactions. Both systems became operational in 2019. As of March 31, 2021, the Commission did not have any transfers from intangible assets under development (2019 - $10.6 million).

The intangible 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.

The Commission has completed its review of Intangible assets and determined there is no impairment.

Note 10 Investment in KXL Expansion Project

An Investment Agreement between TransCanada Pipeline Ltd ("TCPL") and the Commission was executed on March 31, 2020. The Commission, through its newly created subsidiaries, agreed to extend financial support of up to US $5.3 billion (CAD $7.5 billion on the date the agreement was signed), beginning with an equity commitment of up to US $1.06 billion in 2020 for the KXL Expansion Project. Under the agreement, equity contributions were only to be provided up to December 31, 2020 and the contributions totaled CAD $1.036 billion. The balance of the support is in the form of a debt guarantee by the Commission to backstop the financing by TCPL affiliated entities for the KXL Expansion Project.

In 2020, the APMC subsidiaries used the capital contributions received from the Commission to invest in partnership interests of entities affiliated with TCPL. In return for the capital contributions in the partnership, Class A Interests were issued to the contributing subsidiaries according to their contributions. Class A Interests rank above TCPL's equity investment in the entities and have certain voting rights. Capital contributions contributed up to March 31, 2026 earn a return in accordance with contractual terms. This return accrues on a quarterly basis and adjusts the carrying value of the Class A Interests. The Class A Interests issued are subject to call rights which enable TCPL affiliated entities to repurchase the Class A Interests at any time and put rights which enable APMC to sell the Class A Interests subsequent to the in-service date of the Keystone XL pipeline if certain conditions are met.

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During the fifteen months ended March 31, 2021, a return in the form of accretion of $11,836 (2019 – nil) was earned on the Canadian Class A Interests and $21,458 (US$16,402) (2019 – nil) was earned on the US Class A Interests for a total of $33,294 (2019 – nil) which has been recorded as part of the net change in the fair value of the investment. Accretion earned to date on the Canadian Class A Interests may not be recoverable as the fair value of the investment has been written down as discussed later in this note.

On January 8, 2021, TCPL exercised the repurchase right to purchase substantially all of the U.S. Class A Interests held by 2254746 Alberta Sub Ltd. for $632 million (US $497 million) by drawing on the TCPL credit facility guaranteed by APMC (Note 14).

On January 20, 2021, U.S. President Biden revoked the Presidential Permit for the cross-border portion of the Keystone XL Pipeline. As a result of this, TCPL has suspended the advancement of the Keystone XL pipeline project. APMC, along with TCPL, are assessing the implications of the revocation and are considering their options. The Commission has ceased accruing a return on the remaining Class A Interests.

Subsequent to the year end, on June 9, 2021, APMC entered into the final KXL agreement (“the Final KXL Agreement”) with TC Energy as disclosed further in Note 25. Pursuant to the Final KXL Agreement, Class C Interests were issued in exchange for the payment of the debt guarantee cancellation payments made on June 16, 2021. The previous Class A Interests held were redeemed for a nominal amount on June 16, 2021. The Class C Interests received on June 16, 2021 do not have any put rights, voting rights or approval rights with respect to the business and affairs of the TCPL partnerships or carriers. The terms of the Final KXL Agreement have a contractual mechanism for future distribution of proceeds from liquidated assets of the KXL project to APMC, for its Class C interests, and to TCPL.

The Commission has incurred a loss on the estimated fair value of its Investment in the KXL Expansion Project.

The following table provides the fair value measurement hierarchy of the Commission’s assets and liabilities.

Fair value measurement hierarchy of assets at March 31, 2021 (the Commission had no assets and liabilities measured at fair value at December 31, 2019):

			Fair value measurement using		
	Date of valuation	Total	Quoted prices in active markets (Level 1)	Significant observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Assets measured at fair value:					
KXL Investment	March 31, 2021	$ 106,000	Nil	Nil	$ 106,000

Reconciliation of fair value (the Commission had no assets or liabilities measured at FVTPL prior to January 1, 2020):

	KXL Investment
As at January 1, 2020	$ -
Contributions - Canadian Class A interests	383,288
Contributions - US Class A interests	652,836
	1,036,124
Foreign exchange loss recognized in loss	(42,512)
Net change in fair value recognized in loss	(255,831)
TCPL repurchase of US Class A Interests	(631,781)
As at March 31, 2021	$ 106,000

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The fair value of the KXL Investment at March 31, 2021 was estimated by using a market approach to value Keystone XL Phase 4 pipeline assets under an abandonment scenario incorporating inputs for the estimated realizable value of the assets.

The determination of the fair value estimate included significant unobservable inputs: estimated cash inflows and outflows relating to an abandonment scenario. If the estimated cash flows relating to the abandonment scenario increase (decrease), the fair value estimate increases (decreases).

As the liquidation process under the abandonment scenario continues, more information is likely to become available that will impact the significant unobservable inputs. As a result, the estimated fair value will be impacted by events after the reporting period.

Note 11 Term loan receivable

Term loan receivable	March 31, 2021	December 31, 2019
Balance, beginning of period	$ 652,470	$ 590,918
Interest accrued	55,275	61,552
Repayments	(167,851)	-
	539,894	652,470
Credit loss provision	(541)	(261)
Less: current portion	(39,776)	-
Balance, end of period	$ 499,577	$ 652,209

The term loan earns interest at a rate of prime plus six percent, compounded monthly. Per the loan agreement, starting one year after COD (in July 2021), NWRP will make repayments of the loan principal as well as the interest that accrued prior to COD. These repayments will occur over a period of 10 years and the term loan will be fully repaid in June 2031. In addition, NWRP commenced making current interest payments on June 1, 2020.

Six months after COD, a true up of the subordinated debt occurred resulting in NWRP repaying principal of $124,079 on the term loan to the Commission. For the fifteen months ended March 31, 2021, APMC received $43,772 (2019 – nil) in interest payments.

For the fifteen months ended March 31, 2021, finance income of $55,412 (2019 - $61,588) (see Note 22) was reported for the Sturgeon Refinery, comprised of the interest income earned on the term loan of $55,275 (2019 - $61,552) and interest income earned on cash and cash equivalents of $137 (2019 - $36).

While loans to NWRP are outstanding APMC is entitled to a 25 percent voting interest on an Executive Leadership Committee, which is charged with overseeing and making decisions on the construction, start-up and operation of the Sturgeon Refinery. Given this 25 percent voting interest in NWRP, APMC has significant influence over NWRP. As the Commission has no equity ownership interest in NWRP, APMC will not apply equity accounting to the relationship with NWRP (see Note 4c).

Summarized audited financial information (audited by another firm) with respect to NWRP is presented below as of December 31, 2020. This information has been prepared in accordance with IFRS Disclosure of Interests in Other Entities as issued by the IASB.

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	NWRP (100% Interest) 2020	NWRP (100% Interest) 2019
Current assets	$ 218,935	$ 253,790
Non-current assets	11,110,108	11,323,677
Current liabilities	3,146,007	383,934
Non-current liabilities	8,487,798	11,311,691
Partners' equity	(304,762)	(118,158)
Revenue	1,348,251	1,736,210
Net and comprehensive loss attributable to Partners	(186,604)	(687,052)

Non-current assets primarily consist of property, plant and equipment which includes refining assets and land. Current liabilities most significant components are a revolving and non-revolving credit facility which comes due in June 2021. The non-current liabilities include long-term secured notes with maturities from 2022 to 2044 and subordinated debt with the Toll Payers.

Effective January 1, 2019, the light oil refinery ("LOR") transitioned from commissioning and start-up to operations for accounting purposes and was processing synthetic crude oil into refined products. Revenues and expenses relating to the LOR units were recognized in the Partnership's Consolidated Statements of Operations and Comprehensive Loss. The Sturgeon Refinery achieved COD on June 1, 2020. At that point NWRP started earning Tolling revenue from the Toll Payers.

Note 12 Accounts payable

	March 31, 2021	December 31, 2019
Trade payables	$ 471,621	$ 36,184
US income tax payable (Note 18)	4,331	-
Total accounts payable	$ 475,952	$ 36,184

Accounts Payable are comprised of payables from marketing transactions and from Sturgeon Refinery activities. As at March 31, 2021, there was $8,938 (2019 – $36,184) of accounts payable for marketing activities primarily for the March 2021 delivery month, which were cash settled on April 26, 2021.

In addition, there was $462,683 (2019 – nil) of account payables related to Sturgeon Refinery activities consisting of purchase of refinery feedstock, processor tolls and optimization transactions delivered in March 2021. The purchases of refinery feedstock are settled on April 26, 2021. The processor tolls and optimization transactions are net settled against refined product sales proceeds on April 26, 2021.

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	March 31, 2021	December 31, 2019
Balance, beginning of period	$ 84,586	$ 2,707
Amount to be transferred	423,825	870,778
Amount remitted	(449,769)	(788,899)
Balance, end of period	$ 58,642	$ 84,586

APMC acts as agent on behalf of the DOE, marketing the conventional crude oil royalty volumes. The Commission sells the royalty volumes and remits the dollars to the DOE on the 25th of the month following delivery, less a holdback to assist funding APMC's operations.

If the Commission had been considered to be a principal, the Consolidated Statement of Loss and Comprehensive Loss would have included: $483,908 revenues; $60,083 expenses; and $423,825 royalties to be transferred to the DOE respectively (2019 – $951,732 revenues, $80,954 expenses and $870,778 royalties to be delivered to the DOE).

Note 14 KXL Expansion Project Debt Guarantee

Pursuant to the Investment Agreement between TCPL and APMC, the Commission has provided a debt guarantee related to the financing of TCPL affiliate entities, in which an APMC subsidiary has partnership interests, for the KXL Expansion Project (the "Guarantee"). The Guarantee agreement was effective January 4, 2021. The Guarantee was in effect for the entire term to maturity of the TCPL credit facility. The maturity date applicable to lending under the facility was January 4, 2024. On March 26, 2021, TCPL reduced the total amount available under the credit facility from US$4.1 billion to US$1.6 billion pursuant to negotiated amendments. As at March 31, 2021, $854.7 million was the principal amount drawn on the debt at that date. It was management's expectation that there was a significant risk that the borrowers were likely to default on the debt on or before the middle of June 2021, and thus it would be likely that APMC will have a credit loss pursuant to its obligations under the Guarantee.

In the event of any debt guarantee cancellation payment made under the debt guarantee, subsidiaries of the Commission that are partners of the TCPL partnerships would be granted Class C interests in the TCPL partnerships and such Class C interests rank higher than Class A interests in preference in the event of a liquidation and dissolution of the TCPL partnerships. In addition, TCPL has agreed to indemnify the Commission for any debt financing costs included in any debt guarantee cancellation payments made by the Commission under the debt guarantee.

The maximum exposure to credit risk relating to a guarantee is defined as the maximum risk of loss if there was a total default by the debt holder (Note 10).

Subsequent to the year end, on June 9, 2021, APMC entered into the Final KXL Agreement with TC Energy as disclosed further in Note 25. APMC provided total contributions of CAD$1.035 billion on behalf of the TCPL partnerships to fund debt guarantee cancellation payments to the lenders as part of the original investment agreement. The debt guarantee cancellation payments were paid on June 16, 2021 and APMC has no further obligations relating to the Investment Agreement and/or the debt guarantee. Pursuant to the Final KXL agreement, Class C Interests were issued in exchange for the payment of the debt guarantee cancellation payments made on June 16, 2021.

As at March 31, 2021, the undiscounted maximum exposure to credit loss as a result of debt guaranteed by APMC is CAD $1.035 billion, which represents the amount of the debt guarantee cancellation payments that were paid on June 16, 2021 under the Final KXL Agreement. As a result, an ECL provision for expected losses on these guarantees of $1.035 billion has been recognized in the consolidated financial statements as a current liability.

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	March 31, 2021	December 31, 2019
Balance, beginning of period	$ -	$ -
Expected credit loss allowance	1,035,002	-
Balance, end of period	$ 1,035,002	$ -

Note 15 Short term debt

Sturgeon Refinery	March 31, 2021	December 31, 2019
Balance, beginning of period	$ 855,043	$ 635,931
Additions	671,119	219,112
Repayments	(217,590)	-
Balance, end of period	$ 1,308,572	$ 855,043
KXL Expansion Project		
Balance, beginning of period	$ -	$ -
Additions	1,032,117	-
Repayments	(444,050)	-
Balance, end of period	$ 588,067	$ -
Total short term debt, end of period	$ 1,896,639	$ 855,043

The Commission entered into a Lending and Borrowing Agreement with the Province effective April 1, 2014. agreement provides the framework under which APMC may from time to time request the Province to lend money t APMC. The Province and APMC must obtain an Order in Council (approved by the Lieutenant Governor in Counc authorize the lending and borrowing dollar limits. Treasury Board & Finance ("TB&F") is the government unit respor for lending on behalf of the Province.

The Commission has an Order in Council in place that allows it to borrow up to $1.5 billion for funding related t Sturgeon Refinery. As at March 31, 2021, the Commission has $1.309 billion (December 31, 2019 - $855 m outstanding at various interest rates ranging from 0.170% to 0.550%. The tranches of borrowing are repayable various terms not exceeding one year. As of March 31, 2021, the undrawn amount on the Order in Council totals million.

The Commission has an Order in Council in place that allows it to borrow up to $2.0 billion for the Investment of the Expansion Project. As at March 31, 2021, $588 million (December 31, 2019 - nil) is outstanding at various interest ranging from 0.240% to 0.700%. The tranches of borrowing are repayable over various terms not exceeding one As of March 31, 2021, the undrawn amount on the Order in Council totals $1,412 million.

As at March 31, 2021, the Commission's short term debt borrowings with TB&F has contractual maturities as summa below.

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	Total	< 3 months	3-6 months	6-12 months
Short term debt	$ 1,896,639	$ 493,521	$ 666,597	$ 736,521
Accrued interest on short term debt	3,001	1,397	1,092	512
	$ 1,899,640	$ 494,918	$ 667,689	$ 737,033

Note 16 Sturgeon Refinery Processing Agreement provision

As at March 31, 2021, 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 net present value of the unavoidable costs related to the Processing Agreement with NWRP exceeds the economic benefits to be received. The model calculates the net present value of revenues from sales of refined products less feedstock costs and refinery tolls charged by NWRP under the Processing Agreement.

During the fifteen months ended March 31, 2021, there was a $767 million increase in the Sturgeon Refinery Processing Agreement provision consisting of a change to the loss provision of $603 million (2019 - $1,727 million) and accretion expense of $164 million (2019 – nil). The accretion expense was reported as part of finance expense.

The undiscounted future cash net inflows are estimated to be $6.9 billion over the expected life of the project including terminal value at end of life. These cash flows have been discounted using a discount rate of 8.5 percent. The onerous contract provision is expected to be settled in periods up to March 2061.

	March 31, 2021	December 31, 2019
Balance, beginning of period	$ 1,727,000	$ -
Change to loss provision	603,410	1,727,000
Accretion	163,590	-
	2,494,000	1,727,000
Less: current portion	(550,000)	(143,743)
Balance, end of period	$ 1,944,000	$ 1,583,257

APMC uses the GOA budget commodity price forecast for WTI, WCS, condensate and foreign exchange to calculate the net present value. The primary change to the net present value was a weaker gross margin resulting from higher feedstock prices, lower diesel premiums and a stronger Canadian dollar in the near term. In addition the change in the net present value was impacted by: higher operating costs in the near term related to a full year of undiscounted costs, inclusion of project deficiency costs and higher near-term gas prices; movement of the refinery turnaround up two years and increased turnaround duration; offset by lower debt tolls due to lower interest rates and costs related to COD incurred in prior year.

The most impactful pricing variables to the net present value of the contract are forecasted WTI-WCS differential and foreign exchange rates. The net present value of the contract has a sensitivity to changes of USD $1 per barrel for the WTI-WCS differential of +/- $295 million. The net present value of the contract has a sensitivity to changes in foreign exchange, for every $0.01 the Canadian dollar changes from the forecast there is a +/- $112 million change to the net present value of the contract. If the Canadian dollar weakens in relation to the U.S. dollar, there is a positive impact to the net present value of the contract and conversely if the Canadian dollar strengthens in relation to the U.S. dollar, there is a negative impact to the net present value.

Note 17 Financial instruments

The Commission’s financial instruments consist of cash and cash equivalents, cash held in trust, accounts receivable, Investment in KXL Expansion Project, term loan receivable, accounts payable, due to Department of Energy, short term debt, and accrued interest on short term debt. Except for the Investment in KXL Expansion Project, the carrying values

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of these financial instruments approximate the fair value due to the short term nature of these instruments. Refer to Note 3 (d) for further information related to the Commission's accounting policies related to *IFRS 9 – Financial Instruments*.

The Commission is exposed to a variety of financial risks: market risk (interest rate risk), credit risk, liquidity risk and commodity price risk. The nature of the risks faced by the Commission and its policies for managing such risks are detailed below.

(a) Interest rate risk

Interest rate risk is the risk that the future cash flows of a financial instrument will fluctuate because of changes in market interest rates. The Commission is subject to interest rate risk from fluctuations in rates on its cash and cash equivalents balance (Note 5). For the respective periods ending March 31, 2021 and December 31, 2019, a 100 basis point change would have a nominal effect on net income.

There is interest rate risk related to the term loans issued to NWRP. APMC earns interest at a rate of prime plus 6%, compounded monthly. A 100 basis point rise in prime would have improved finance income for the fifteen months ended March 31, 2021 by $4.2 million (12 months ended December 31, 2019 - $6.5 million). A 100 basis point decline in prime would have reduced finance income by $4.2 million (12 months ended December 31, 2019 - $6.4 million).

(b) Credit risk

Credit risk is the risk of financial loss to the Commission if a customer or party to a financial instrument fails to meet its contractual obligation and arises principally from the Commission's cash and cash equivalents, cash held in trust, accounts receivable and term loan and other financial instruments. The maximum amount of credit risk exposure of these instruments is limited to the carrying value of the balances disclosed in these consolidated financial statements.

Credit risk also arises from the possibility of third-party defaults on the repayment of debt whereby APMC has provided guarantees.

The Commission manages its exposure to credit risk on cash and cash equivalents by placing these financial instruments with the Consolidated Cash Investment Trust Fund (Note 5).

A substantial portion of the Commission's accounts receivable are with its agents and customers in the oil and gas industry and are subject to normal industry credit risk. The Commission monitors the credit risk and credit rating of all customers on a regular basis. Aged receivable balances are monitored and a credit loss provision is provided in the period in accordance with IFRS 9. Any credit losses on accounts receivable would be charged on to the DOE.

APMC has issued term loans totaling $315 million (2019 – $439 million) to NWRP. NWRP is an investment grade counterparty. Bonds issued by NWRP received a BBB credit rating (BBB+ in 2019) from Standard and Poor's. For NWRP, this is subordinated debt which ranks behind senior secured debt. A trust structure has been set up under which APMC receives monies owed under the term loan after amounts owed to senior debt holders and certain other amounts have been paid. A credit loss provision for the term loan and related accrued interest has been provided in the period per IFRS 9.

Credit risk relating to financial guarantee contracts is mitigated through APMC's involvement in the management of the debtor and decisions relating to the KXL Expansion Project as a result of its' partnership interests in the debtor entities. The Commission monitors the changes in the risk of the specified debtor defaulting on the debt relating to the guarantees to assess for changes in credit risk. For the maximum exposure to credit risk on financial guarantee contracts refer to Note 14.

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Credit loss provision

Accounts receivable - trade	March 31, 2021	December 31, 2019
Balance, beginning of period	$ 220	$ 153
Change to loss provision	28	67
Balance, end of period	$ 248	$ 220
Accounts receivable - Sturgeon Refinery		
Balance, beginning of period	$ -	$ -
Change to loss provision	226	-
Balance, end of period	$ 226	$ -
Term loan receivable and accrued interest		
Balance, beginning of period	$ 261	$ 236
Change to loss provision	280	25
Balance, end of period	$ 541	$ 261
Total change to loss provision for the period	$ 534	$ 92

The loss provision for trade accounts receivable is recorded to General and Administrative Expenses (Note 23) in the Consolidated Statement of Loss and Comprehensive Loss. The loss provisions for Sturgeon Refinery accounts receivable and the term loan receivable have been recorded to Provisions for Sturgeon Refinery 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 and receivables strategies. In addition, APMC has the ability to obtain financing through external banking credit facilities or from TB&F.

As at March 31, 2021, excluding short term debt, the Commission's non-derivative financial liabilities have contractual maturities (including interest payments where applicable) are summarized below. The maturities for short term debt are presented in Note 15.

	Total	< 1 Year	1-3 Years	3-5 Years	More than 5 Years
Accounts payable	$ 475,952	$ 475,952	$ -	$ -	$ -
Due to the Department of Energy	58,642	58,642	-	-	-
KXL Expansion Project Debt Guarantee	1,035,002	1,035,002	-	-	-
Sturgeon Refinery Processing Agreement provision	2,494,000	550,000	814,000	551,000	579,000
	$ 4,063,596	$ 2,119,596	$ 814,000	$ 551,000	$ 579,000

The term loan is structured so that the Commission will receive repayments starting one year after COD of the Sturgeon Refinery. The outstanding amount owed will be repaid straight line over a 10 year period with accrued interest.

For the short term debt, the Commission intends to borrow additional funds from TB&F and then to match the repayment terms detailed for the term loan above.

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(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 and tolls at the Sturgeon Refinery. In addition, the Commission's financial position and results are also impacted by changes in estimates of future commodity prices used in the determination of the net present value of the Processing Agreement. Movement in commodity prices could have a significant positive or negative impact on the Commission's net loss (see Note 16).

(e) Foreign exchange risk

Foreign currency 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 related primarily to the Commission's KXL Investment. A portion of the KXL Investment was denominated in a foreign currency and this exposed the Commission to the risk that the fair value will fluctuate due to changes in the exchange rate.

As of March 31, 2021, the Commission is no longer exposed to this risk as substantially all of its KXL US Investment (see Note 10) has been repurchased by TCPL (through the U.S. Class A Interests).

(f) Offsetting financial assets and liabilities

The Commission enters into contracts with single shipper pipelines, where APMC sells oil to the carrier at the inlet and purchases the oil back at the terminus of the pipeline. The agreements are written to allow for offsetting of accounts receivable and accounts payable, which are presented on a net basis on the Consolidated Statement of Financial Position. The following table presents the recognized financial instruments that are offset as a result of netting arrangements and the intention to settle on a net basis with counterparties.

	Gross amounts of recognized financial assets (liabilities)	Gross amounts of recognized financial assets (liabilities) offset in the statement of financial position	Net amounts of financial assets (liabilities) recognized in the statement of financial position
Accounts receivable (Note 7)	$ 403,716	$ 1,738	$ 401,978
Accounts payable (Note 12)	(477,839)	(1,887)	(475,952)
Net position, March 31, 2021	(74,123)	(149)	(73,974)
Accounts receivable (Note 7)	88,564	4,568	83,996
Accounts payable (Note 12)	(42,538)	(6,354)	(36,184)
Net position, December 31, 2019	$ 46,026	$ (1,786)	$ 47,812

Capital management

The capital structure includes the Commission's equity. The Commission's objectives when managing capital are to safeguard the Commission's ability to continue as a going concern and provide returns to the DOE through responsible marketing of conventional crude oil royalty volumes and its other business activities. The Commission does not have any externally imposed restrictions on its capital. There has been no change in the Commission's capital management strategy.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the fifteen months ended March 31, 2021 and twelve months ended December 31, 2019

(in thousands of Canadian dollars unless otherwise stated)

Note 18 Income taxes

As noted above, the Commission is exempted from Canadian federal and provincial corporate income taxes. However, 2254746 Alberta Sub Ltd., a Delaware incorporated company and 2254746 Alberta Ltd., an Alberta incorporated company have exposure to US federal and state corporate income taxes.

During the fifteen month period ended March 31, 2021, the Commission recorded $5,199 (2019 – nil) of income tax expense due to the Internal Revenue Service ("IRS") in the United States. During that 2021 period, accretion income of $21,458 (US$16,402) (Note 10) was earned on the U.S. Class A Interests held by 2254746 Alberta Sub Ltd. (the "US subsidiary").

US corporate taxes were due on the accretion income earned by the US subsidiary and the remainder was distributed by an intercorporate dividend to the Canadian holding company, 2254746 Alberta Ltd., which also resulted in withholding taxes being paid to the IRS. The total of the US corporate taxes and withholding taxes paid to the IRS of $5,199 has all been expensed as it is uncertain that any of the withholding taxes will be recoverable.

As of March 31, 2021, $4,331 (US$3,445) of income taxes payable to the IRS is included in accounts payable (Note 12).

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

Note 19 Commitments

(in millions)	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	Beyond March 2026	Total
NWRP Tolls	$ 1,076	$ 1,139	$ 1,014	$ 1,042	$ 1,019	$ 21,123	$ 26,413

NWRP Tolls:

Under the processing agreement, after COD, the Commission is obligated to pay a monthly toll comprised of: senior debt; operating; class A subordinated debt; equity; and incentive fees on 37,500 barrels per day of bitumen (75% of the project's feedstock). The Sturgeon Refinery attained COD June 1, 2020. The processing agreement has a term of 30 years starting with the Toll Commencement Date (June 1, 2018). The toll includes flow through costs as well as costs related to facility construction, estimated to be $10.0 billion (2019 - $10.1 billion).

The Commission has very restricted rights to terminate the agreement, and if it is terminated the Commission remains obligated to pay its share of the senior secured debt component of the toll incurred to date.

The nominal tolls under the processing agreement assuming: a $10.0 billion FCC; market interest rates; and 2% operating cost inflation rate, are estimated above.

The tolls are undiscounted and are up to the end of the processing agreement (May 31, 2048).

The reduction in tolls compared to 2019 ($26.575 billion) consists of 15 months of tolls since December 31, 2019 falling off the calculation offset by higher operating costs related to increased carbon taxes.

These undiscounted tolls do not take into account the net margin received on the sale of APMC's bitumen feedstock.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission
For the fifteen months ended March 31, 2021 and twelve months ended December 31, 2019
(in thousands of Canadian dollars unless otherwise stated)

Note 20 Related party transactions

The DOE pays the Commission a fee to market crude oil on its behalf under conventional crude oil marketing activities, reported as marketing fees within the Consolidated Statement of Loss and Comprehensive Loss. The amounts owing to the DOE have been disclosed in Note 13.

The Commission enters into transactions with the DOE, a related party, in the normal course of business. For the fifteen months ended March 31, 2021, the DOE incurs costs for salaries on behalf of the Commission, as recognized under wages and benefits of $2,716 (2019 - $2,200) within the Consolidated Statement of Loss and Comprehensive Loss. In addition, no DOE salaries were capitalized within intangible assets (2019 - $79).

Service Alberta, a related party provided the software and maintenance services totaling $604 for the fifteen months ended March 31, 2021 (2019 - $453).These expenditures are recognized within the Consolidated Statement of Loss and Comprehensive Loss. In addition, no technology services related to software development have been capitalized within intangible assets (2019 - $598).

The Commission has outstanding short term debt with TB&F. For more details see Note 15.

Information on the Term Loan Receivable from NWRP and summarized financial information for NWRP is found in Note 11. Refer to Note 4(c) for a description of the Sturgeon Refinery, Note 4(d) for the NWRP monthly toll commitment and Note 16 for the Sturgeon Refinery Processing Agreement Provision.

Information on the Commission's investment in the KXL Expansion Project Class A partnership interests is found in Note 10 and the KXL Expansion Project Debt Guarantee is found in Note 14.

The Board members of the Commission, executive management and their close family members are deemed related parties of the Commission. Transactions with close family members are immaterial; compensation for Board members and executive management is disclosed in Note 21.

Note 21 Salaries and benefit disclosure

Key management personnel include the Commission’s Chief Executive Officer, Vice President Finance, Director of Operations, Director of Finance, Director of Business Development and Board Members. The amounts in the consolidated financial statements relating to board members and key management compensation for the fifteen months ended March 31, 2021 and the twelve months ended December 31, 2019 are as follows:

	15 months ended March 31, 2021				**2019 (12 months)**
	Base Salary	Other Cash Benefits (2)	Other Non-cash Benefits (3)	Total	Total
Board Members (1)	$ -	$ 171	$ -	$ 171	$ 96
Chief Executive Officer	381	112	8	501	401
Vice President, Finance (4)	15	3	-	18	-
Director of Operations (5)	338	91	5	434	243
Director of Finance	296	32	4	332	263
Director of Business Development (6)	138	27	-	165	-
Executive Director, Business Development (7)	-	-	-	-	264

(1) The Chair of the Board (Deputy Minister, DOE) and one director (Assistant Deputy Minister, DOE) are unpaid. There are five outside Board Members. The outside Board Members receive an annual retainer and meeting fees.

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the fifteen months ended March 31, 2021 and twelve months ended December 31, 2019

(in thousands of Canadian dollars unless otherwise stated)

(2) As per their employment contracts, the key management personnel receive cash payments in lieu of benefits. No bonuses were paid during the year.
(3) Included in Other Non-cash benefits is parking.
(4) The Vice President, Finance was hired effective March 15, 2021.
(5) The Director of Operations was hired effective March 31, 2019.
(6) The Director of Business Development was hired effective August 18, 2020.
(7) The Executive Director, Business Development resigned effective October 11, 2019.

Note 22 Segment information

The Commission's reportable segments were determined based on differences in products and support services offered under its mandate as disclosed in Note 1. The Commission's operating segments consist of conventional crude marketing operations, the Sturgeon Refinery and the KXL Expansion Project.

These reportable segments of the Commission have been derived because they are the segments: (a) that engage in business activities from which revenues are earned and expenses are incurred; (b) whose operating results are regularly reviewed by the Commission's chief operating decision maker, identified as the Commission's Chief Executive Officer, to make decisions about resources to be allocated to each segment and assess its performance; and (c) for which discrete financial information is available. The Commission regularly provides financial information on revenues and expenses of each segment, but not total assets or liabilities by segment.

For Fifteen Months ended March 31, 2021	Conventional Crude Oil Marketing Operations	Sturgeon Refinery	KXL Expansion Project	Total
Revenues				
Refinery sales	$ -	$ 1,131,367	$ -	$ 1,131,367
Marketing fee income	5,256	-	-	5,256
	5,256	1,131,367	-	1,136,623
Finance income	291	55,412	-	55,703
	5,547	**1,186,779**	**-**	**1,192,326**
Expenses				
Refinery feedstock purchases	-	909,227	-	909,227
Refinery tolls & other	-	837,150	-	837,150
General and administrative expenses	7,682	6,151	5,107	18,940
Amortization	1,331	-	-	1,331
Finance expense	-	178,144	1,839	179,983
Foreign exchange loss	88	1,988	34,749	36,825
Provisions for Sturgeon Refinery	-	603,916	-	603,916
Loss allowance for KXL Expansion Project Debt Guarantee	-	-	1,035,002	1,035,002
Fair value loss on investment in KXL Expansion Project	-	-	255,831	255,831
	9,101	**2,536,576**	**1,332,528**	**3,878,205**
Loss before income taxes	(3,554)	(1,349,797)	(1,332,528)	(2,685,879)
Income taxes	-	-	5,199	5,199
Net loss and comprehensive loss	**$ (3,554)**	**$ (1,349,797)**	**$ (1,337,727)**	**$ (2,691,078)**

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission
For the fifteen months ended March 31, 2021 and twelve months ended December 31, 2019
(in thousands of Canadian dollars unless otherwise stated)

For Twelve Months ended December 31, 2019	Conventional Crude Oil Marketing Operations	Sturgeon Refinery	KXL Expansion Project	Total
Revenues				
Refinery sales	$ -	$ -	$ -	$ -
Marketing fee income	6,747	-	-	6,747
	6,747	-	-	6,747
Finance income	138	61,588	-	61,726
	6,885	**61,588**	**-**	**68,473**
Expenses				
Refinery feedstock purchases	-	-	-	-
Refinery tolls & other	-	201,011	-	201,011
General and administrative expenses	6,621	-	-	6,621
Amortization	532	-	-	532
Finance expense	-	14,805	-	14,805
Foreign exchange loss	-	-	-	-
Provisions for Sturgeon Refinery	-	1,727,025	-	1,727,025
Loss allowance for KXL Expansion Project Debt Guarantee	-	-	-	-
Fair value loss on investment in KXL Expansion Project	-	-	-	-
	7,153	**1,942,841**	**-**	**1,949,994**
Loss before income taxes	(268)	(1,881,253)	-	(1,881,521)
Income taxes	-	-	-	-
Net loss and comprehensive loss	**$ (268)**	**$ (1,881,253)**	**$ -**	**$ (1,881,521)**

Note 23 General and administrative expenses

General and administrative expenses include the following:

	Note	For Fifteen Months Ended March 31, 2021	For Twelve Months Ended December 31, 2019
General and administrative expenses			
Wages & benefits	20	$ 5,350	$ 4,041
Software & maintenance	20	1,268	581
Consulting		11,770	1,579
Dues & subscriptions		288	173
Directors' fees	21	171	96
Change to loss provision for accounts receivable	17	28	67
Other		65	84
Total general and administrative expenses		**$ 18,940**	**$ 6,621**

Notes to the Consolidated Financial Statements

Alberta Petroleum Marketing Commission

For the fifteen months ended March 31, 2021 and twelve months ended December 31, 2019
(in thousands of Canadian dollars unless otherwise stated)

Note 24 Supplemental cash flow information

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

	For Fifteen Months Ended March 31, 2021	For Twelve Months Ended December 31, 2019
Cash held in trust	$ (11,282)	$ -
Accounts receivable	(318,236)	(76,820)
Inventory	(51,711)	-
Accounts payable	439,768	(2,521)
Due to Department of Energy	(25,944)	81,879
Changes in non-cash working capital from operating activities	**$ 32,595**	**$ 2,538**

Note 25 Subsequent events

Short term debt

As of the issuance date of these consolidated financial statements, the Commission borrowed additional funds of $237 million for the Sturgeon Refinery from TB&F. The interest rates associated with these borrowings range from 0.0608% to 0.1444%. The tranches of these borrowings are repayable over various terms maturing at between April 29, 2021 and July 26, 2021.

During the same period, the Commission repaid TB&F $40 million related to the Sturgeon Refinery.

As for the KXL Expansion Project, the Commission borrowed additional funds of $1.035 billion with interest rates ranging from 0.0608% and 0.1338%. The tranches of these borrowings are repayable over various terms maturing between May 27, 2021 and July 16, 2021.

The Commission also repaid TB&F $183 million related to the KXL Expansion Project during the same period.

KXL Expansion Project

Subsequent to the year end, on June 9, 2021, the APMC, as directed by the Alberta Government, and TC Energy have reached an agreement for an orderly exit from the KXL project and partnership. The two parties will continue to explore all options to recoup the government’s investment in the project. Final costs to the government are expected to be approximately $1.3 billion.

The Final KXL Agreement provided for the following items as clarification and an exit from the original agreements. APMC provided total contributions of CAD$1.035 billion on behalf of the TCPL partnerships to fund debt guarantee cancellation payments to the lenders as part of the original investment agreement. The debt guarantee cancellation payments were paid on June 16, 2021 and APMC has no further obligations relating to the Investment Agreement and/or the debt guarantee. In exchange for APMC making the guarantee cancellation payments through its wholly owned Canadian and US subsidiaries, Class C Interests were received from the TCPL partnerships. Class A Interests were redeemed for a nominal amount on June 16, 2021. The Final KXL Agreement also provides a mechanism for future distribution of proceeds from liquidated assets of the KXL project to APMC, for its Class C interests, and to TCPL. APMC has reflected the terms of the Final KXL Agreement in determining its estimates for the Investment in the KXL Expansion Project and the KXL Expansion Project Debt Guarantee in the consolidated financial statements as at March 31, 2021.

Balancing Pool

Financial Statements

Year ended December 31, 2020

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Independent auditor's report

To the Board of Directors of the Balancing Pool

Our opinion

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Balancing Pool as at December 31, 2020 and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards (IFRS).

What we have audited
The Balancing Pool's financial statements comprise:

- the statement of financial position as at December 31, 2020;
- the statement of income (loss) and comprehensive income (loss) for the year then ended;
- the statement of cash flows for the year then ended; and
- the notes to the financial statements, which include significant accounting policies and other explanatory information.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence
We are independent of the Balancing Pool in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

Other information

Management is responsible for the other information. The other information comprises the Management's Discussion and Analysis.

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

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

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

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

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

In preparing the financial statements, management is responsible for assessing the Balancing Pool's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Balancing Pool or to cease operations, or has no realistic alternative but to do so.

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

Auditor's responsibilities for the audit of the financial statements

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

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

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- 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 Balancing Pool'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 Balancing Pool's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Balancing Pool to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

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

PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Alberta
April 14, 2021

Statement of Financial Position

Balancing Pool

(in thousands of Canadian dollars)	202 0	2019
Assets		
Current assets		
Cash and cash equivalents	223,737	96,037
Trade and other receivables (Note 5)	109,192	85,650
Right-of-use assets (Note 9)	89	289,921
Current portion of long-term receivables (Note 6)	-	1,980
Current portion of Hydro Power Purchase Arrangement (Note 8 b i)	-	110,667
Intangible assets (Note 7)	-	2,500
	333,018	586,755
Right-of-use assets (Note 9)	-	89
Property, plant and equipment	15	14
Total Assets	333,033	586,858
Liabilities		
Current liabilities		
Trade payables and other accrued liabilities (Note 11)	399,712	212,524
Current portion of related party loan (Note 17)	202,932	202,765
Current portion of reclamation and abandonment provision (Note 12)	263	676
Current portion of lease liability (Note 13)	91	410,025
	602,998	825,990
Reclamation and abandonment provision (Note 12, Note 15)	38,188	32,183
Lease liability (Note 13)	-	91
Related party loan (Note 17)	503,546	503,219
Total Liabilities	1,144,732	1,361,483
Net liabilities attributable to the Balancing Pool deferral account (Note 1, 14)	(811,699)	(774,625)
Contingencies and commitments (Note 15)		
Subsequent events (Note 18)		

On behalf of the Balancing Pool:

Original signed by *Original signed by*

Greg Clark, *Chair* Greg Pollard, *Vice-Chair*

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

Statement of Income(Loss) and Comprehensive Income (Loss)

Balancing Pool

(in thousands of Canadian dollars)	2020	2019
Revenue from contracts with customers		
Sale of electricity and ancillary service (Note 3, Note 17)	641,046	882,584
Consumer collection (Note 3)	145,404	172,985
	786,450	1,055,569
Other income (loss) from operating activities		
Changes in fair value of Hydro Power Purchase Arrangement (Note 8 b i)	(19,608)	20,152
Payments in Lieu of Tax	15,856	21,149
Interest income	1,250	2,341
Changes in fair value of Small Power Producer Contracts	-	393
	(2,502)	44,035
Expenses		
Cost of sales (Note 16)	776,795	871,966
Reclamation and abandonment provision (Note 12, Note 15)	6,993	10,544
Mandated costs (Note 17)	5,069	4,700
General and administrative	6,690	5,155
Commercial dispute costs and Power Purchase Arrangement provision expense	2,320	123
	797,867	892,488
Income (loss) from operating activities	(13,919)	207,116
Other income (expense)		
Finance expense (Note 10)	(23,310)	(35,391)
Other income	155	106
	(23,155)	(35,285)
Change to the Balancing Pool deferral account (Note 14)	(37,074)	171,831

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

Statement of Cash Flows

Balancing Pool

(in thousands of Canadian dollars)	2020	2019
Cash flow provided by (used in)		
Operating activities		
Change to the Balancing Pool deferral account	(37,074)	171,831
Adjustments for		
Amortization and depreciation (Note 9)	289,975	299,660
Reclamation and abandonment provision (Note 12)	6,993	10,544
Power Purchase Arrangement provision	-	(2,132)
Line loss provision	-	(32,191)
Fair value changes on Small Power Producer Contracts	-	(393)
Fair value changes on Hydro Power Purchase Arrangement (Note 8 b i)	19,608	(20,152)
Finance expense (Note 10)	23,310	35,391
Emission credits retired (Note 7)	14,446	89,279
Reclamation and abandonment expenditures (Note 12)	(1,973)	(2,299)
Net change in other assets:		
Long-term receivable (Note 6)	1,980	1,961
Net change in non-cash working capital:		
Trade and other receivables	(23,541)	115,599
Trade payable and other accrued liabilities	187,187	(92,832)
Net cash provided by operating activities	480,911	574,266
Investing activities		
Purchase of property, plant and equipment	(9)	(16)
Purchase of emission credits (Note 7)	(11,947)	(64,879)
Net cash used in investing activities	(11,956)	(64,895)
Financing activities		
Hydro Power Purchase Arrangement net receipts (Note 8 b i)	91,059	77,016
Lease payments (Note 13)	(417,483)	(437,891)
Payments on related party loan (Note 17)	(734,548)	(1,037,767)
Proceeds from issue of related party loan (Note 17)	735,419	829,491
Finance expense on related party loan	(15,702)	(19,983)
Small Power Producer Contracts net payments	-	(51)
Net cash used in financing activities	(341,255)	(589,185)
Change in cash and cash equivalents	127,700	(79,814)
Cash and cash equivalents, beginning of year	96,037	175,851
Cash and cash equivalents, end of year	223,737	96,037

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

Notes to Financial Statements

Balancing Pool

1. Reporting Entity and Nature of Operations

Formation and Duties of the Balancing Pool

The Balancing Pool exists to facilitate policy implementation and to support the functioning of the electricity industry for the benefit of Albertans. The *Electric Utilities Act (2003)* ("EUA") and certain regulations made under it establish the mandate of the Balancing Pool, which is principally to manage certain assets, liabilities, revenues, and expenses associated with the ongoing evolution of Alberta's electric industry.

The Balancing Pool was originally established in 1998 as a separate financial account of the Power Pool Council (the "Council") and commenced operations in 1999. The Council was a statutory corporation established under the *Electric Utilities Act of Alberta (1995)*. With the proclamation of the EUA on June 1, 2003, the Balancing Pool was established as a separate statutory corporation (the "Corporation"). The assets and liabilities of the Council that related to the duties, responsibilities and powers of the Balancing Pool were transferred to the Corporation.

Under the EUA, the Corporation is required to operate without a profit or loss (Note 14). No share capital for the Corporation has been issued.

The Balancing Pool Board of Directors (the "Board") consists of individual members who are independent of persons having a material interest in the Alberta electric industry. The members of the Board are appointed by the Minister of Energy of the Government of Alberta ("Minister of Energy").

The Balancing Pool is required to respond to certain extraordinary events during the operating period of all of the Power Purchase Arrangements ("PPAs"), such as force majeure, PPA unit destruction, PPA Buyer or PPA Owner default, or the termination of a PPA. In the event of termination of a PPA by a PPA Buyer, the Balancing Pool assumed the rights and obligations of the PPA Buyer pursuant to that PPA at the time of termination (assuming the PPA continues). Under the EUA the Balancing Pool was required to manage generation assets in a commercial manner.

The head office and records of the Balancing Pool are located at Suite 2350, 330 - 5th Avenue S.W., Calgary, Alberta, Canada.

Activities of the Balancing Pool

The initial allocation of assets and liabilities to the Balancing Pool was charged to a deferral account. Differences between annual revenues and expenditures are also charged or credited to the Balancing Pool deferral account.

The EUA requires that the Balancing Pool forecast its revenues and expenses. Any excess or shortfall of funds in the accounts is to be allocated to, or provided by, electricity consumers over time.

Notes to Financial Statements

Balancing Pool

Expiry of the Power Purchase Arrangements ("PPAs")

The thermal PPAs (Genesee, Keephills and Sheerness) and the Hydro PPA expired on December 31, 2020. Offer control of these PPAs reverted back to the PPA Owners effective January 1, 2021.

The Balancing Pool's business activities after December 31, 2020 will include the collection of funds from electricity consumers, payments (refund) in lieu of tax, repayment of the outstanding loan with the Provincial Government, resolving outstanding commercial and legal disputes related to the PPAs, resolving other legal matters, collection of funds from retailers related to the Utility Bill Deferral Program, acting as agent for Small Scale Generators and settlement of certain financial accounts.

Revenue from Contracts with Customers

i) Sale of electricity, ancillary service and generating capacity

The Balancing Pool earned revenue from the sale of electricity and ancillary service sourced from the PPAs it held, namely, Genesee, Sheerness and Keephills.

Electricity that was not otherwise contracted was sold into the spot market. Ancillary services from the PPAs were sold to the Alberta Electric System Operator ("AESO") through a competitive exchange.

ii) Consumer collection

Pursuant to Section 82 of the EUA, the Balancing Pool collects or allocates an annualized amount from customers. Consumer collection from the AESO is being accounted for as revenue of the Balancing Pool. The Balancing Pool has applied judgment in determining that the consumer collection collected via rate Rider F, as specified in the EUA, is analogous to a contract with a customer. The legislation contained in the EUA established the Balancing Pool's right to recover operating shortfalls from electricity customers via Rider F of the AESO tariff and can be interpreted as a contract with a customer.

Other Income

i) Hydro Power Purchase Arrangement ("Hydro PPA")

Pursuant to Section 85 of the EUA, the Balancing Pool held the Hydro PPA. As such, the Balancing Pool retained the right to the market value of the associated electricity and was responsible for the PPA obligations from certain hydro plants in the Province of Alberta. The cash flows associated with the Hydro PPA were based on the electricity market price multiplied by a notional amount of production, less PPA obligations as outlined in the PPA. The expected net present value of these estimated payments was recorded as an asset and any revaluation adjustment is included in net results of income (loss).

ii) Investment income and changes in fair value of investments

Cash, cash equivalents and investments held by the Balancing Pool generate investment income consisting of interest.

Notes to Financial Statements

Balancing Pool

iii) Payments (refunds) in Lieu of Tax ("PILOT")

Pursuant to Section 147 of the EUA, the Balancing Pool collects (refunds) a notional amount of tax from electricity companies controlled by municipal entities that are active in Alberta's competitive electricity market and are otherwise exempt from the payment of tax under the *Income Tax Act* or the *Alberta Corporate Tax Act*. The Balancing Pool does not calculate instalment payments or refunds and it does not audit PILOT filings. PILOT instalments are calculated by the payer and PILOT filings are subject to audit by Alberta Tax and Revenue.

Expenses

i) Cost of sales

Under the terms of the various PPAs, the Balancing Pool was obligated to pay certain fixed and variable costs to the PPA Owners of the various generation assets. Included in Cost of Sales are costs associated with the administration of the *Small Scale Generation Regulation*.

ii) Other costs

Under the terms of government legislation, the Balancing Pool is obligated to make payments to certain entities for such matters as reclamation and abandonment and force majeure. The Minister of Energy may direct the Balancing Pool to fund specific payments under Section 148 of the EUA, which amounts are included in mandated costs.

2. Basis of Presentation

These financial statements for the year ended December 31, 2020 have been prepared by management in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and include as comparative information the year ended December 31, 2019.

These financial statements were authorized and approved for issue by the Board of the Balancing Pool on April 14, 2021.

3. Summary of Significant Accounting Policies

The significant accounting policies used in the preparation of these financial statements are as follows:

Basis of Measurement

These financial statements have been prepared on a historical cost convention, except for the revaluation of certain financial instruments, which are measured at fair value.

Notes to Financial Statements

Balancing Pool

Revenue from Contracts with Customers

The Balancing Pool applies IFRS 15, *Revenue from contracts with customers*, for its revenue arrangements.

(a) Sale of electricity and ancillary services

Revenues from the sale of electricity and ancillary services are recognized on an accrual basis in the period in which generation occurred, which is the point in time when control of the goods and services passes to the customer. Sale of electricity and ancillary services is measured at the fair value of the consideration received or receivable. The Corporation has elected to recognize revenue based on amounts invoiced.

The timing of revenue recognition does not result in any contract assets or liabilities and there are no unfulfilled performance obligations at any point in time. Furthermore, no significant judgments or estimates are required with respect to the recognition of revenue associated with the sale of electricity and ancillary services.

(b) Consumer collection (allocation)

Upon adoption of IFRS 15, consumer collection revenue is recognized in the statement of income and comprehensive income on an accrual basis in the period in which amounts are charged (refunded) to electricity customers based on an annualized tariff amount, which is the point in time when control of the goods and services passes to the customer. Consumer collection revenue is measured at the fair value of the consideration received or receivable. The Corporation has elected to recognize revenue based on amounts invoiced.

The timing of revenue recognition does not result in any contract assets or liabilities and there are no unfulfilled performance obligations at any point in time. The Balancing Pool has applied judgment in the application of its accounting policy that the consumer collection (allocation) represents a contract with a customer in the scope of IFRS 15 (see Note 1).

Other Income (Expense) Recognition

(a) Hydro Power Purchase Arrangement

The Hydro PPA is recorded at the present value of the estimated future net receipts under this PPA. The increase in value of this asset with the passage of time (accretion) is recognized on an accrual basis. Any change in valuation as a result of changes in underlying assumptions is recognized in income (loss) from operating activities.

(b) Investment income

Investment income resulting from interest is recorded on an accrual basis when there is reasonable assurance as to its measurement and collectability.

(c) Payments (refunds) in Lieu of Tax

PILOT funds are accrued based on instalments received from or refunds paid to a municipal entity for a particular tax year. PILOT payments are calculated by the municipal entities and are subject to assessment and audit by Alberta Tax and Revenue Administration. Adjustments, if any, arising from audits, or other legal proceedings, are recorded in the current year, upon receipt.

Notes to Financial Statements

Balancing Pool

Income Taxes

No provision has been made for current or deferred income tax as the Balancing Pool is exempt from Federal and Provincial income tax.

Cash and Cash Equivalents

Cash and cash equivalents are comprised of cash on deposit at the bank.

Trade and Other Receivables

Trade and other receivables are classified and measured at amortized cost less any impairment.

Intangible Assets (Emission Credits)

Emission credits, which have been purchased or have been acquired through PPA-negotiated settlements, and which are held for compliance purposes, are recorded by the Balancing Pool as limited life intangible assets. Emission credits are limited to a life between six to eight years depending on the vintage. These assets are recognized initially at fair value based upon a market price. Purchased emissions credits are measured at cost on the purchase date. Emission credits held for compliance purposes are not amortized, but are expensed as the associated benefits are realized.

The emission credits are expected to be used to satisfy future environmental compliance obligations of the PPAs associated with the *Carbon Competitiveness Incentive Regulation* for 2019 and *Technology Innovation and Emissions Reduction Regulation* for 2020. Compliance obligations resulting from emissions are recognized as a provision and measured at the market value of allowances needed to settle the obligation.

Long-Term Receivables

Cash settlement amounts due from a former PPA counterparty were accounted for as long-term receivables. These assets were recognized initially at fair value. After initial recognition they are measured at amortized cost using the effective interest method less any impairment losses. The effective interest method calculates the amortized cost of a financial asset and allocates the interest income over the term of the financial asset using the effective interest rate.

Hydro Power Purchase Arrangement

The Hydro PPA is a derivative financial instrument classified as and measured at fair value through profit or loss. The PPA is recorded as of the period end date at its fair value. Fair value is measured as the present value of the estimated future net payments to be received (or paid) under the arrangement and reflects management's best estimate based on generally accepted valuation techniques and supported by observable market prices and rates when available. Fair value for these contracts is based on forecasted future prices.

Notes to Financial Statements

Balancing Pool

Leases

The PPAs transferred to the Balancing Pool substantially all the benefits and some of the risks of ownership and therefore the arrangements are classified as finance leases, with the Corporation as the lessee. A lease is considered to be a finance lease when the terms of the lease transfer substantially all of the risks and rewards incidental to ownership of the leased assets to the lessee. Finance leases are capitalized at the lease's commencement at the fair value of the leased property. The Corporation has recognized lease liabilities and right-of-use assets for the PPAs on adoption of IFRS 16, *Leases*. The Corporation has also recognized a lease liability and right-of-use asset for the office lease.

Lease liabilities are measured at the present value of the remaining lease payments for the PPAs and the office lease. The lease liabilities have been discounted at the Balancing Pool's one year borrowing rate of 1.8% (2019 – 1.9%).

Right-of-use assets have been recognized for the PPAs on adoption of IFRS 16, *Leases*. The right-of-use asset has been amortized on a straight-line basis over the life of the PPAs and the office lease.

Property, Plant and Equipment ("PP&E")

PP&E are stated at cost less accumulated depreciation and accumulated impairment losses. Cost includes expenditure directly attributable to the acquisition of the asset. When parts of an item of PP&E have different useful lives, they are accounted for as separate items (major components) of property, plant and equipment. Gains and losses on disposal of an item of property, plant, and equipment are determined by comparing the proceeds from disposal with the carrying amount of PP&E, and are recognized within other income in profit and loss. PP&E, which comprises office equipment, is depreciated on a straight-line basis over a three- to five-year useful life.

Impairment – Non-Financial Assets

For the purpose of impairment testing, non-financial assets are grouped together into the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets — a cash generating unit ("CGU").

The carrying amounts of non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment, such as decreased forward electricity prices. If any such indication exists, then the amount recoverable from the asset is estimated. The recoverable amount is the greater of the value in use or fair value less costs to dispose.

Value in use is based on the estimated net future cash flows discounted to their present value. The discounted cash flow is determined using a discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. The recoverable amount is generally computed by reference to the present value of the future cash flows. An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in the Statement of Income (loss) and Comprehensive Income (loss).

Notes to Financial Statements

Balancing Pool

Impairment losses recognized in prior years are reassessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation and amortization, if no impairment loss had been permitted to be recognized.

Impairment – Financial Assets

The Corporation applies IFRS 9, *Simplified approach to measuring expected credit losses*, which uses a lifetime expected loss allowance for all trade and other receivables. To measure the expected credit losses, trade receivables and other receivables have been grouped based on shared credit risk characteristics and the days past due.

Trade and other receivables are written off when there is no reasonable expectation of recovery. Indicators that there is no reasonable expectation of recovery include, amongst others, the failure of a debtor to engage in a repayment plan with the Corporation, and a failure to make contractual payments for a period of greater than 120 days past due.

No impairment provision has been recorded at December 31, 2020 related to trade and other receivables. The Corporation considers trade and other receivables to be low risk.

Reclamation and Abandonment Obligations

Reclamation and abandonment obligations include legal obligations requiring the Balancing Pool to fund the decommissioning of tangible long-lived assets such as generation and production facilities. A provision is made for the estimated cost of site restoration.

Reclamation and abandonment obligations are measured as the present value of management's best estimate of expenditures required to settle the present obligation at the period end date. Subsequent to the initial measurement, the obligations are adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as a finance expense. Increases / decreases due to changes in the estimated future cash flows are expensed. Actual costs incurred upon settlement of the reclamation and abandonment obligations are charged against the provision to the extent the provision was established.

The Balancing Pool's estimates of reclamation and abandonment obligations are based on reclamation standards that meet current regulatory requirements. The estimate of the total liability of future site restoration costs may be subject to change based on amendments to laws and regulations. Accordingly, the amount of the liability will be subject to re-measurement at each period end date.

The Balancing Pool has recorded an estimate of the cost to remediate certain Isolated Generating Unit sites in Alberta. Actual expenditures incurred to remediate these sites will reduce this liability and any increase in this liability will be charged to expense when estimated costs are known to exceed the remaining liability balance.
An amount has also been provided for the decommissioning of the H.R. Milner generating station which is being accreted annually; revisions to this estimate will be charged or credited to net results of income (loss).

Notes to Financial Statements

Balancing Pool

Pursuant to Section 5 of the *Power Purchase Arrangements Regulation*, a PPA Owner may apply to the Alberta Utilities Commission ("AUC") to receive from the Balancing Pool the amount by which decommissioning costs related to a former PPA unit exceed the amount the PPA Owner collected from consumers before January 1, 2001 and subsequently through the PPA, provided that the unit has ceased generating electricity and the application is made within one year of the termination or expiration of the PPA. Section 5 of the *Power Purchase Arrangements Regulations* does not apply after December 31, 2018.

The reclamation and abandonment provision includes an estimate of the expected future costs associated with PPA decommissioning costs.

The discount rate used to value these liabilities is based upon the risk-free rate and adjusted for other risks associated with these liabilities.

Other Provisions

Provisions for obligations are recognized when the Balancing Pool has a present legal or constructive obligation as a result of past events, it is probable that an outflow of resources will be required to settle the obligation and the amount can be reliably estimated. Provisions are not recognized for future operating losses.

Provisions are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the end of the reporting period. The discount rate used to determine the present value is a risk-free discount rate that reflects current market assessments of the time value of money. The increase in the provision due to the passage of time is recognized as finance expense.

4. Significant Accounting Judgments, Estimates and Assumptions

The timely preparation of the financial statements requires that management make estimates and assumptions and use judgment regarding the reported value of assets and liabilities, disclosures of contingent assets and liabilities at the date of the financial statements and the amounts of revenues and expenses reported for the year. Such estimates reflect management's best estimate of future events as of the date of the financial statements. These financial statements have, in management's opinion, been properly prepared using careful judgment within reasonable limits of materiality and within the framework of the significant accounting policies summarized below. Accordingly, actual results will differ from estimated amounts as future confirming events occur.

Critical Judgments in Applying Accounting Policies

Management has made critical judgments in applying accounting policies, including when:

- concluding that the consumer collection (allocation) is accounted for as revenue (refund of revenue) from a contract with a customer (Notes 1, 14); and
- forecasting future power prices and capacity factors.

These critical judgments have been made in the process of applying accounting policies and have a significant effect on the amounts recognized in the financial statements.

After December 31, 2020, forecasting future power prices and capacity factors is no longer subject to critical judgments as the PPAs expired on December 31, 2020.

Notes to Financial Statements

Balancing Pool

Key Sources of Estimation Uncertainty

Since the determination of certain assets, liabilities, revenues and expenses is dependent upon and determined by future events, the preparation of these financial statements requires the use of estimates and assumptions. These estimates and assumptions have been made using careful judgment. Actual results are likely to differ from the results derived using these estimates. The following are items that have been derived using key assumptions concerning future outcomes and subject to several other key sources of estimation uncertainty. As a consequence, there is a significant risk of a material adjustment to the carrying amount of assets and liabilities within the next financial year:

- Hydro Power Purchase Arrangement (Note 8 b i)
- Intangible assets (Note 7)
- Reclamation and abandonment provision (Note 12)
- Contingent legal matters (Note 15).

In the opinion of management, these financial statements have been properly prepared in accordance with IFRS, within reasonable limits of materiality and the framework of the significant accounting policies summarized in Note 3 to the financial statements.

After December 31, 2020, the Hydro PPA and intangible assets are no longer subject to key sources of estimation uncertainty.

5. Trade and Other Receivables

(in thousands of dollars)	December 31, 2020	December 31, 2019
Trade receivables	98,069	76,950
Retailer receivables	9,123	-
Other receivables	2,000	8,700
	109,192	85,650

On May 12, 2020, the Government of Alberta initiated a program that permitted residential, farm, and small commercial businesses to defer the payment of utility bills for 90 days. The Balancing Pool received a Ministerial Order from the Minister of Energy on April 22, 2020 directing the Balancing Pool to reserve $119.0 million for the 90-day utility payment deferral program to assist retailers with funding. At December 31, 2020 the Balancing Pool has issued $36.1 million in funding to the retailers and received repayments of $27.0 million from retailers.

At December 31, 2020 no accounts receivable amounts are past due.

Notes to Financial Statements

Balancing Pool

6. Long-term Receivables

(in thousands of dollars)	December 31, 2020	December 31, 2019
Opening balance, long-term receivable	1,980	3,941
Accretion	20	39
Cash received from PPA settlement	(2,000)	(2,000)
Closing balance, long-term receivable	-	1,980
Less: Current portion	-	(1,980)
	-	-

$2.0 million in cash was received in December 2018, 2019 and 2020 in relation to the PPA settlements reached in November 2016.

7. Intangible Assets

(in thousands of dollars)	December 31, 2020	December 31, 2019
Opening balance, emission credits	2,500	26,899
Additions from purchases	11,947	64,879
Retirement of emission credits	(14,447)	(89,278)
Closing balance, emission credits	-	2,500

At December 31, 2020, the Balancing Pool had no emission credits (2019 – $2.5 million). Emission credits can be used to offset environmental compliance obligations associated with the PPAs. In 2020, the Balancing Pool purchased $11.9 million (2019 – $64.9 million) in emission credits. Over the course of 2020, $14.4 million (2019 – $89.3 million) in emission credits were retired to satisfy PPA environmental compliance obligations.

No impairments of emission credits were recognized during the year ended December 31, 2020 (2019 – $nil).

Notes to Financial Statements

Balancing Pool

8. Accounting for Financial Instruments

8. a) Risk Management Overview

The Balancing Pool's activities expose or exposed the Corporation to a variety of financial risks: market risk (including fluctuating market prices, plant availability, PPA capacity payments and interest rates), credit risk and liquidity risk. The Balancing Pool has developed Risk Management and Credit Policies that define the organization's tolerance for risk and set out procedures for quantifying and monitoring exposures. Exposures and compliance with the policies are regularly monitored by management and the Board of Directors.

Market Risk — Power

i) Fluctuating Market Prices: Changes in the market price for electricity and ancillary services affected the amount of revenues that the Balancing Pool received from the thermal and Hydro PPAs. Electricity prices are volatile, and are affected by supply and demand, which in turn are influenced by fuel costs (e.g. natural gas prices), weather patterns, plant availability and power imports or exports. Economic activity is a key contributor to market price risk as it relates to the demand for electricity. Market price risk may be managed through the use of financial forward sale contracts for electricity.

ii) Plant Availability: Changes in plant availability impacted the expected level of generation output and associated revenues and expenses of the Balancing Pool. According to the terms of the PPA, the Balancing Pool is entitled to availability incentive payments when the plant generated at levels below target availability. If the plant generated above the target availability, the Balancing Pool was required to make payments to the PPA Owner of the plant. The Balancing Pool is not entitled to availability incentive payments during an event of force majeure.

iii) Capacity Payment: The Balancing Pool is exposed to interest rate risk in relation to the annual capacity payments.

Market Risk

i) Interest Rate Risk: The Balancing Pool is exposed to interest rate risk on the related party loan. There is the possibility that the value of the related party loan will change due to fluctuations in market interest rates.

ii) Counterparty Credit Risk: The Balancing Pool was exposed to counterparty credit risk. In the event of a default on payments from counterparties to the Hydro PPA, a financial loss may have been experienced by the Balancing Pool. Credit risk is managed in accordance with the Credit Policy which requires that all counterparties maintain investment-grade status level. Status of counterparty credit was regularly monitored by management and the Audit and Finance Committee. The Balancing Pool had minimal credit risk related to its receivables and cash as they consisted primarily of amounts owing from the AESO, a government-related entity. The Balancing Pool does not consider any of the trade or long-term accounts receivable to be impaired or past due. Bad debts related to the Utility Payment Deferral Program will be collected through a COVID rate rider approved by the AUC.

Notes to Financial Statements

Balancing Pool

iii) Liquidity Risk: Liquidity risk is the risk that the Balancing Pool will not be able to meet its financial obligations as they fall due. To manage this risk, management forecasts cash flows for a period of 12 months and beyond and will adjust the consumer collection according to the *Balancing Pool Regulation* and borrow from the Government of Alberta. The changes to the EUA, enacted in December of 2016, provide the Balancing Pool with the capacity to borrow from the Government of Alberta (Note 17).

The following table analyzes the Balancing Pool's financial and other liabilities into relevant maturity groupings based on the remaining period from the period end date to the contract maturity date.

	1 year	2 – 5 years	Total
(in thousands of dollars)	December 31, 2020		
Trade payables	81,284	-	81,284
Other accrued liabilities	318,428	-	318,428
Related party loan – principal	201,184	498,802	699,986
Related party loan – interest	1,748	4,744	6,492
Reclamation and abandonment	263	38,188	38,451
Lease liability	91	-	91
Total	602,998	541,734	1,144,732
(in thousands of dollars)	December 31, 2019		
Trade payables	61,931	-	61,931
Other accrued liabilities	150,593	-	150,593
Related party loan – principal	197,393	498,476	695,869
Related party loan – interest	5,372	4,743	10,115
Reclamation and abandonment	676	32,183	32,859
Lease liability	410,025	91	410,116
Total	825,990	535,493	1,361,483

8. b) Analysis of Financial Instruments

i) Hydro Power Purchase Arrangement

The Balancing Pool was the counterparty to the Hydro PPA, a financial arrangement recorded as an asset at the present value of estimated amounts to be received, net of Hydro PPA obligations, over the remaining term of the Hydro PPA.

The notional production of electricity under the Hydro PPA was 1,626 gigawatt hours ("GWh") per annum for 2020. Hydro PPA receipts were settled on a monthly basis.

The Hydro PPA expired on December 31, 2020. At December 31, 2020, the net present value of the Hydro PPA was nil (2019 – $110.7 million).

Notes to Financial Statements

Balancing Pool

Under the terms of the Hydro PPA, the Balancing Pool has remitted to TransAlta Corporation ("TransAlta") charges related to line losses for the previous 20 years. The AUC, in its decision released in December 2017, ruled that the methodology for which line losses is calculated will be revised, dating back to 2006. The revised methodology will result in a credit for line loss charges previously paid by the Balancing Pool to TransAlta. Under the terms of the PPA, TransAlta will be required to pass the line loss credit onto the Balancing Pool. An estimate of $34.4 million has been included in accounts receivable for the historical line loss settlement period of 2006 to 2013.

Hydro Power Purchase Arrangement *(in thousands of dollars)*	2020	2019
Hydro Power Purchase Arrangement, opening balance	110,667	135,340
Accretion and current year change	(19,608)	(28,995)
Line loss credit	-	32,191
Net cash receipts	(91,059)	(77,016)
Revaluation of Hydro Power Purchase Arrangement asset	-	49,147
Hydro Power Purchase Arrangement, closing balance	-	110,667
Less: Current portion receivable	-	(110,667)
	-	-

8. c) Fair Value Hierarchy

Financial instruments carried at fair value are categorized as follows:

(in thousands of dollars)	Quoted prices in active markets for identical assets Level 1	Significant other observable inputs Level 2	Significant unobservable inputs Level 3	Total
		December 31, 2020		
Assets				
Cash and cash equivalents	223,737	-	-	223,737
	223,737	-	-	223,737
		December 31, 2019		
Assets				
Cash and cash equivalents	96,037	-	-	96,037
Hydro Power Purchase Arrangement	-	-	110,667	110,667
	96,037	-	110,667	206,704

Notes to Financial Statements

Balancing Pool

i) Level 1

Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities.

ii) Level 2

Assets and liabilities in Level 2 include valuations using inputs other than Level 1 quoted prices for which all significant inputs are observable, either directly or indirectly. Fair values for fixed income investments are determined using quoted market prices in active markets.

iii) Level 3

Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. Changes in valuation methods may result in transfers into or out of an assigned level. There were no transfers between Level 3 and Level 2. The Hydro PPA and Small Power Producer Contract values are determined using discounted cash flow forecast methods and supported by observable market prices when available. Methodologies have been developed to determine the fair value for these contracts based on forecast of the hourly electricity market price in Alberta's hourly market using proprietary third-party merit order dispatch model. Management reviews the discounted cash flow forecasts on an annual basis.

9. Right-of-Use Assets

(in thousands of dollars)	Genesee PPA	Keephills PPA	Sheerness PPA	Office Lease	Total
At January 1, 2019	271,217	152,942	174,846	393	599,398
Amortization and depreciation	(135,608)	(76,471)	(87,423)	(152)	(299,654)
Reassessment of lease liability	(6,506)	(1,471)	(1,757)	-	(9,734)
At December 31, 2019	129,103	75,000	85,666	241	290,010
Less: Current portion	(129,103)	(75,000)	(85,666)	(152)	(289,921)
	-	-	-	89	89
At January 1, 2020	129,103	75,000	85,666	241	290,010
Amortization and depreciation	(129,238)	(75,684)	(84,893)	(152)	(289,967)
Reassessment of lease liability	135	684	(773)	-	46
At December 31, 2020	-	-	-	89	89

During 2020, $290.0 million in amortization and depreciation was recorded and a reassessment of the lease liability of $0.05 million was recorded due to a change in the monthly lease payments for the PPAs. This reduction to the liability has been applied to the right-of-use assets for the PPAs. Effective December 31, 2020, the Genesee, Keephills and Sheerness PPAs expired.

Notes to Financial Statements

Balancing Pool

10. Finance Expense

(in thousands of dollars)	2020	2019
Interest expense – related party loan	15,326	18,948
Interest expense – lease liability	7,412	15,991
Accretion expense – reclamation and abandonment	572	452
	23,310	35,391

11. Trade Payable and Other Accrued Liabilities

(in thousands of dollars)	2020	2019
Trade payables	81,284	61,931
Accrued liabilities – Greenhouse gas obligation	237,852	66,891
Accrued liabilities – Line loss provision	67,902	68,440
Accrued liabilities – Other	12,674	15,262
	399,712	212,524

12. Reclamation and Abandonment Provision

(in thousands of dollars)	H.R. Milner Generating Station	Isolated Generation Sites	Sundance A Generating Station	Total
At January 1, 2019	10,469	1,756	11,937	24,162
Net increase (decrease) in liability	(1,459)	2,190	9,813	10,544
Liabilities paid in year	(298)	(2,001)	-	(2,299)
Accretion expense	196	33	223	452
At December 31, 2019	8,908	1,978	21,973	32,859
Less: Current portion	(279)	(397)	-	(676)
	8,629	1,581	21,973	32,183
At January 1, 2020	8,908	1,978	21,973	32,859
Net increase (decrease) in liability	1,552	(20)	5,461	6,993
Liabilities paid in year	(399)	(1,574)	-	(1,973)
Accretion expense	155	34	383	572
At December 31, 2020	10,216	418	27,817	38,451
Less: Current portion	(177)	(86)	-	(263)
	10,039	332	27,817	38,188

Notes to Financial Statements

Balancing Pool

12. a) Decommissioning Costs of H.R. Milner Generating Station

Under the Asset Sale Agreement for the H.R. Milner generating station between the Balancing Pool and ATCO Power Ltd ("ATCO"), which was executed in 2001, the Balancing Pool assumed the liability for the costs of decommissioning the station at the end of operations. When the asset was subsequently re-sold to Milner Power Limited Partnership in 2004, the Balancing Pool retained the liability for decommissioning the generating station. In 2011, a bilateral agreement was reached with Milner Power Limited Partnership wherein the Balancing Pool's exposure to future decommissioning costs was capped at $15.0 million. As at December 31, 2020, a total of $4.6 million has been paid for decommissioning the Milner generating site, leaving a balance of $10.4 million remaining. A further $0.2 million is expected to be incurred in 2021. These costs have been discounted at the risk-free rate of 0.15% (2019 – 1.7%). At December 31, 2020, the provision was increased by $1.6 million (2019 – $1.5 million decrease) to reflect a change in the discount rate. Expenditures of $0.4 million were incurred in 2020 (2019 – $0.3 million).

12. b) Isolated Generation Sites

Under the *Isolated Generating Units* and *Customer Choice Regulations of the EUA*, the Balancing Pool is liable for the reclamation and abandonment costs associated with various Isolated Generation sites. Expenditures of $1.6 million (2019 – $2.0 million) were incurred in 2020. Pursuant to the Negotiated Settlement Agreements approved by the AUC, the ultimate payment of these costs must be reviewed and approved by the Remediation Review Committee. The Remediation Review Committee was established to monitor, verify and approve all costs associated with the reclamation and abandonment of the Isolated Generation sites. Estimated reclamation and abandonment costs have been discounted at 0.15% (2019 – 1.7%). The provision is based upon management's best estimate and the timing of the costs. Management anticipates the Isolated Generation projects will conclude at the end of 2022.

12. c) Decommissioning Costs of PPAs

Pursuant to Section 5 of the *Power Purchase Arrangements Regulation*, a PPA Owner may apply to the AUC to receive from the Balancing Pool the amount by which decommissioning costs related to a former PPA unit exceed the amount the PPA Owner collected from consumers before January 1, 2001 and subsequently through the PPA, provided that the unit has ceased generating electricity and the application is made within one year of the termination or expiration of the PPA. Section 5 of the *Power Purchase Arrangements Regulations* does not apply after December 31, 2018.

In December 31, 2020, the Balancing Pool recorded a $5.5 million increase (2019 – $9.8 million increase) to the provision for decommissioning the Sundance A unit. In December 2018, TransAlta submitted an application to the AUC to decommission Sundance A. The provision for Sundance A is based upon management's best estimate of decommissioning costs. Estimated decommissioning costs were discounted at 0.15% (2019 – 1.7%). The AUC will determine the amount owed to TransAlta. See also Note 15.

Notes to Financial Statements

Balancing Pool

13. Lease Liability

(in thousands of dollars)	Genesee PPA	Keephills PPA	Sheerness PPA	Office Lease	Total
At January 1, 2019	340,830	225,640	274,886	393	841,749
Finance expense	6,476	4,287	5,222	6	15,991
Lease payments	(175,150)	(116,360)	(146,226)	(155)	(437,891)
Reassessment of lease liability	(6,505)	(1,471)	(1,757)	-	(9,733)
At December 31, 2019	165,651	112,096	132,125	244	410,116
Less: Current portion	(165,651)	(112,096)	(132,125)	(153)	(410,025)
	-	-	-	91	91
At January 1, 2020	165,651	112,096	132,125	244	410,116
Finance expense	3,001	2,031	2,377	3	7,412
Lease payments	(168,786)	(114,811)	(133,730)	(156)	(417,483)
Reassessment of lease liability	134	684	(772)	-	46
At December 31, 2020	-	-	-	91	91

The Balancing Pool has recognized lease liabilities in relation to the Genesee, Keephills and Sheerness PPAs and the office lease. The lease liabilities have been discounted using a rate of 1.8% (2019 – 1.9%).

14. Capital Management

The Balancing Pool's objective when managing capital is to operate as per the requirements of the EUA, which requires the Balancing Pool to operate with no profit or loss and no share capital and to forecast its revenues, expenses, and cash flows. Any excess or shortfall of funds in the accounts is to be allocated to, or provided by, electricity consumers over time. During 2016, the Alberta Government enacted amendments to the *Balancing Pool Regulation* that defined the method by which the Balancing Pool would calculate the amounts to be allocated to, or provided by, electricity consumers through to 2030. In January 2017, the Balancing Pool signed a loan agreement with the Government of Alberta. The loan agreement was put in place through Alberta Treasury Board and Finance to fund operating losses of the Balancing Pool, including obligations associated with the terminated PPAs.

A reconciliation of the opening and closing Balancing Pool deferral account is provided below.

Balancing Pool Deferral Account *(in thousands of dollars)*	2020	2019
Deferral account, beginning of year	(774,625)	(946,456)
Change to the Balancing Pool deferral account	(37,074)	171,831
Deferral account, end of year	(811,699)	(774,625)

Notes to Financial Statements

Balancing Pool

In December 2019, the Board of Directors approved a 2020 consumer collection of $2.50/megawatt ("MWh") for a total collection from electricity consumers of $145.4 million in accordance with the *Balancing Pool Regulation*. In October 2020, the Board of Directors approved a 2021 consumer collection of $2.30/MWh for an estimated total collection from electricity consumers of $130.0 million in accordance with the *Balancing Pool Regulation*.

15. Contingencies and Commitments

Reclamation and Abandonment

TransAlta has submitted an application to the AUC to decommission Sundance A and is seeking $46.0 million (2019 - $41.4 million) in funding from the Balancing Pool. The Balancing Pool disagrees with several aspects of the application. The Balancing Pool has a provision of $27.8 million to decommission Sundance A. The final amount due will be determined by the AUC.

Legal Claim

On June 12, 2019, the Balancing Pool received a statement of claim from a power producer seeking $17.5 million in damages from the Balancing Pool. The Balancing Pool has filed a statement of defence and will vigorously defend the claim. The Balancing Pool considers the claim to be without merit. Furthermore, Section 92 of the *Electric Utilities Act* provides the Balancing Pool with strong liability protection for such claims. As at December 31, 2020, no contingent liability has been recorded (2019 - $nil).

Legal Claim

On January 27, 2021, the Balancing Pool received a statement of claim from a power producer related to the line loss rule proceeding and it is seeking $10.3 million in damages from the Balancing Pool. The Balancing Pool is preparing its statement of defence and considers the claim to be without merit. At December 31, 2020, no contingent liability has been recorded.

Market Surveillance Administrator ("MSA") Investigation

On August 5, 2020 the Balancing Pool received Notice of Investigation from the MSA. The MSA is investigating to assure itself that the Balancing Pool is complying with all of its obligations and ensuring the Balancing Pool acted within the limits of the PPA framework and in accordance with the laws that govern Alberta. To date, there has been no finding of fault and the Balancing Pool has not accrued any contingent liability in respect of this matter.

The Balancing Pool is involved in other legal claims and legal proceedings arising in the ordinary course of business. Although the outcome of such matters cannot be predicted with certainty, the Corporation does not consider the Balancing Pool's exposure to litigation to be material to these financial statements. Accruals for litigation, claims and assessments are recognized if the Balancing Pool determines that the loss is probable and the amount can be reasonably estimated. The Balancing Pool believes it has made adequate provisions for such legal claims.

Notes to Financial Statements

Balancing Pool

16. Cost of Sales

(in thousands of dollars)	2020	2019
Cost of Power Purchase Arrangements and power marketing	488,956	590,151
Small scale generator costs	147	-
Gain on the retirement of emission credits	(2,283)	(17,845)
Amortization and depreciation on right-of-use assets	289,975	299,660
	776,795	871,966

Included as a reduction to cost of sales is a gain on the retirement of emission credits in the amount of $2.3 million (2019 – $17.8 million). The gain on emission credits is a result of procuring emission credits at a price lower than the Climate Change Emission Management Fund rate of $30 per tonne.

On adoption of IFRS 16, the portion of the capacity payment that is based upon indices and rates (capital recovery charge, indexed fuel charge and indexed operational and maintenance charge) has been classified as the fixed lease payment. The fixed lease payment portion of the total capacity payment is used to establish the lease liability. As the capacity payments are invoiced by the PPA Owner, the fixed lease payment portion of the total capacity payment is recorded against the lease liability and not recorded through the income statement. The balance of the capacity payment is expensed through the income statement.

17. Related Party Transactions

Key Management Compensation

Key management includes members of the Board of the Balancing Pool and the Chief Executive Officer. The compensation paid or payable to key management for services is shown below.

Key Management Compensation *(in thousands of dollars)*	2020	2019
Salaries, other short-term employee benefits and severance	519	822
Total	519	822

Government-Related Entity

The Balancing Pool considers itself to be a government-related entity as defined by IAS 24 – *Related Party Disclosures* and applies the exemption from the disclosure requirements of Paragraph 18 of IAS 24 – *Related Party Disclosures*. The members of the Board are appointed by the Minister of Energy of the Government of Alberta. The financial information of the Balancing Pool is being consolidated by the Ministry of Energy.

In January 2017, the Balancing Pool signed a loan agreement with the Government of Alberta. The loan agreement was put in place through Alberta Treasury Board and Finance to fund operating losses of the Balancing Pool, including obligations associated with the terminated PPAs.

Notes to Financial Statements

Balancing Pool

(in thousands of dollars)	Interest Rate	December 31, 2020
Long-term note due on Sept. 13, 2023	2.65%	503,546
Short-term discount note due on Feb. 18, 2021	0.14%	74,986
Short-term discount note due on Mar. 26, 2021	0.18%	127,946
		706,478
Less: Current portion		(202,932)
		503,546

	Interest Rate	December 31, 2019
Long-term note due on Sept. 13, 2023	2.65%	503,219
Short-term discount note due on Jan. 02, 2020	1.97%	127,986
Short-term discount note due on Feb. 24, 2020	1.97%	74,779
		705,984
Less: Current portion		(202,765)
		503,219

At December 31, 2020, the Balancing Pool had $706.5 million (2019 – $706.0 million) in short-term discount and long-term notes issued to the Government of Alberta, including accrued interest of $6.5 million (2019 – $5.6 million). During 2020, payments of $14.8 million were remitted on the outstanding loan. Fair value of the loan is the same as the amortized cost of borrowing. During 2020, interest of $15.3 million was paid on the related party loan (2019 – $18.9 million).

Directed by the Minister of Energy, the Balancing Pool is mandated to make payments to the Office of the Utilities Consumer Advocate ("UCA") to cover 80% of their annual operating costs and to the Transmission Facilities Cost Monitoring Committee ("TFCMC") to cover 100% of their annual costs. In 2020, the Balancing Pool expensed $5.0 million (2019 – $4.6 million) for the UCA and $0.01 million (2019 – $0.1 million recovery) for the TFCMC.

The Balancing Pool also considers the AESO a government-related entity. The EUA requires the Balancing Pool to forecast its revenues and expenses with any excess or shortfall of funds in the accounts to be allocated to, or provided by, electricity consumers over time. Pursuant to the EUA, the AESO facilitates the collection or distribution of any excess or shortfall through an annualized amount included in the AESO's transmission tariff. In 2020, the Balancing Pool collected $145.4 million (2019 – $173.0 million) from electricity consumers through the AESO's transmission tariff.

The AESO also operates the spot market in Alberta and remits payment for electricity sold in the spot market. In 2020 the Balancing Pool received $631.6 million (2019 – $875.2 million) related to the sale of electricity for the PPAs.

Notes to Financial Statements

Balancing Pool

18. Subsequent Events

Related Party Transactions

On February 18, 2021 and March 26, 2021 the maturing related-party short-term notes were re-financed with the terms noted below.

(in thousands of dollars)	Interest Rate	Amount re-financed
Short-term discount note due on May 19, 2021	0.10%	75,000
Short-term discount note due on June 24, 2021	0.14%	128,000

Post-Closure Stewardship Fund

Financial Statements

For the year ended March 31, 2021

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Auditor General
OF ALBERTA

Independent Auditor's Report

To the Minister of Energy

Report on the Financial Statements

Opinion

I have audited the financial statements of the Post-Closure Stewardship Fund, which comprise the statement of financial position as at March 31, 2021, 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, 2021, 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 *Energy Annual Report 2020-2021*. The other information comprises the information included in the *Energy Annual Report 2020-2021* 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 *Energy Annual Report 2020-2021* 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.

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

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

Those charged with governance are responsible for overseeing the Post-Closure Stewardship Fund's financial reporting process.

Auditor's responsibilities for the audit of the financial statements

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

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

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

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

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

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

June 4, 2021
Edmonton, Alberta

Statement of Operations

Post-Closure Stewardship Fund
Year ended March 31, 2021
(in thousands)

	2021		2020
	Budget	Actual	Actual
Revenue			
Injection Levy (Note 3)	$ 230	$ 219	$ 261
Investment Income	-	6	38
Net Operating Results	230	225	299

The accompanying notes are part of these financial statements.

Statement of Financial Position

Post-Closure Stewardship Fund
As at March 31, 2021
(in thousands)

	2021	2020
Assets		
Cash (Note 4)	$ 1,316	$ 1,083
Accounts Receivable	133	141
Net Assets	**$ 1,449**	**$ 1,224**
Net Assets at Beginning of Year	$ 1,224	$ 925
Annual Operating Results	225	299
Net Assets at End of Year	**$ 1,449**	**$ 1,224**

The accompanying notes are part of these financial statements.

Statement of Change in Net Financial Assets

Post-Closure Stewardship Fund
Year ended March 31, 2021
(in thousands)

	2021		2020
	Budget	Actual	Actual
Annual Operating Results	$ 230	$ 225	$ 299
Increase in Net Assets	$ 230	$ 225	$ 299
Net Assets at Beginning of Year	-	1,224	925
Net Assets at End of Year	**$ 230**	**$ 1,449**	**$ 1,224**

The accompanying notes are part of these financial statements.

Statement of Cash Flows

Post-Closure Stewardship Fund
Year ended March 31, 2021
(in thousands)

	2021	2020
Operating Transactions		
Net Operating Results	$ 225	$ 299
Decrease (Increase) in Accounts Receivable	8	5
Increase in Cash and Cash Equivalents	**$ 233**	**$ 304**
Cash and Cash Equivalents at Beginning of Year	1,083	779
Cash and Cash Equivalents at End of Year	**$ 1,316**	**$ 1,083**

The accompanying notes are part of these financial statements.

Notes to Financial Statements

Post-Closure Stewardship Fund
March 31, 2021
(in thousands)

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. These rates are reviewed every three years at a minimum, and will be amended if necessary.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES

These financial statements are prepared in accordance with Canadian Public Sector Accounting Standards.

(a) **Basis of Financial Reporting**

Revenues
Revenues are reported on the accrual basis of accounting. The volume of carbon dioxide injected is based upon reported injection provided by the operator. Third party verification on the volume of injection will take place in the month of October, for injection to September 30. The Injection Levy is calculated based on the net present value of estimated future costs arising from the injection.

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

NOTE 3 INJECTION LEVY

The Injection Levy is set aside for Post-Closure Care of the injection site. Post-Closure Care occurs after the issuance of the Closure Certificate and includes the continual monitoring costs of the captured carbon dioxide injection sites and any remediation of the sites that may be required.

At March 31, 2021, there is only one approved carbon dioxide injection site. The estimated present value of the future costs for this site, based on modeling of potential requirement under current technology, is $4.7 million. Currently, approximately 24% of the site's capacity has been used. The project is expected to inject for a 25-year period.

As the site remains active and no Closure Certificate has been issued, there is no expectation of any withdrawals from the Fund at this time.

NOTE 4 CASH

Cash is represented by funds held within the Post-Closure Stewardship Fund's Consolidated Cash Investment Trust Fund (CCITF) bank account. The fund earns interest at an effective rate of 0.51% per annum (2020 - 1.80%).

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, 2021

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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, 2021, 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, 2021, and the results of its operations, its changes in net financial assets, and its cash flows for the year then ended in accordance with Canadian public sector accounting standards.

Basis for opinion

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

Other information

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

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

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

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

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

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

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

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

Auditor's responsibilities for the audit of the financial statements

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

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

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

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

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

June 16, 2021
Edmonton, Alberta

Statement of Operations

Canadian Energy Centre Ltd.
Year ended March 31, 2021

	2021		For the Period October 9, 2019 To March 31, 2020
	Budget	**Actual**	**Actual**
Revenues			
Government transfers			
Government of Alberta grants	$ 1,673,443	$ 1,673,443	$ 5,000,000
	1,673,443	**1,673,433**	**5,000,000**
Expenses (Schedule 1)			
Resource Development and Management	4,702,370	3,734,983	1,971,073
	4,702,370	**3,734,983**	**1,971,073**
Annual operating (deficit) / surplus	(3,028,927)	(2,061,540)	3,028,927
Annual (deficit) / surplus	**(3,028,927)**	**(2,061,540)**	**3,028,927**
Share capital (Note 10)	-	-	6,800
Accumulated surplus at beginning of year	117,375	3,035,727	-
Accumulated surplus at end of year (Note 9)	**$ (2,911,552)**	**$ 974,187**	**$ 3,035,727**

The accompanying notes and schedules are part of these financial statements

Statement of Financial Position

Canadian Energy Centre Ltd.
As at March 31, 2021

	2021	2020
Financial Assets		
Cash and cash equivalents (Note 5)	$ 1,846,504	$ 2,707,258
Accounts receivable (Note 6)	99,875	1,068,576
	1,946,379	**3,775,834**
Liabilities		
Accounts payable and accrued liabilities (Note 8)	1,015,679	771,592
	1,015,679	**771,592**
Net Financial Assets	**930,700**	**3,004,242**
Non-Financial Assets		
Prepaid expenses	43,487	31,485
	43,487	**31,485**
Net Assets		
Accumulated surplus (Note 9)	**974,187**	3,035,727
	$ 974,187	**$ 3,035,727**

Contingent liabilities (Note 11)
Contractual obligations (Note 12)

The accompanying notes and schedules are part of these financial statements

Approved by:

[Original signed by Hon. Sonya Savage]

Chair of the Board of Directors

Approved by:

[Original signed by Tom Olsen]

Chief Executive Officer/Managing Director

Statement of Change in Net Financial Assets

Canadian Energy Centre Ltd.
Year ended March 31, 2021

	2021		For the Period October 9, 2019 To March 31, 2020
	Budget	**Actual**	**Actual**
Annual (deficit) / surplus	**$ (3,028,927)**	**$ (2,061,540)**	**$ 3,028,927**
Share capital	-	-	6,800
Increase in prepaid expenses	-	(12,002)	(31,485)
(Decrease) / increase in net financial assets	**(3,028,927)**	**(2,073,542)**	**3,004,242**
Net financial assets at beginning of year	117,375	**3,004,242**	-
Net financial assets at end of year	**$ (2,911,552)**	**$ 930,700**	**$ 3,004,242**

The accompanying notes and schedules are part of these financial statements

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Statement of Cash Flows

Canadian Energy Centre Ltd.
Year ended March 31, 2021

	2021	For the Period October 9, 2019 To March 31, 2020
Operating transactions		
Annual (deficit) / surplus	$ (2,061,540)	$ 3,028,927
(Increase)/decrease in accounts receivable	968,701	(1,068,576)
Increase in prepaid expenses	(12,002)	(31,485)
Increase in accounts payable and accrued liabilities	244,087	771,592
Cash (applied to) provided by operating transactions	**(860,754)**	**2,700,458**
Financing transactions		
Share capital	-	6,800
Cash provided by financing transactions	**-**	**6,800**
(Decrease) / increase in cash and cash equivalents	**(860,754)**	**2,707,258**
Cash and cash equivalents at beginning of year	**2,707,258**	**-**
Cash and cash equivalents at end of year	**$ 1,846,504**	**$ 2,707,258**

The accompanying notes and schedules are part of these financial statements

Notes to the Financial Statements

Canadian Energy Centre Ltd.
Year ended March 31, 2021

Note 1 AUTHORITY

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

The Corporation is wholly owned by Her Majesty the Queen in the Right of Alberta as represented by the Minister of Energy. It is governed by a Board of Directors appointed by the Province. The Board consists of three Cabinet Ministers appointed by the Government of Alberta.

The mandate of the Corporation is to promote Canada as the supplier of choice for the world's growing demand for responsibly produced energy.

As a provincial corporation, the Corporation is exempt from income taxes under the *Income Tax Act.*

Note 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES

These financial statements are prepared in accordance with Canadian Public Sector Accounting Standards.

(a) Basis of Financial Reporting

Revenues

All revenues are reported on the accrual basis of accounting.

<u>Government Transfers</u>
Transfers from all governments are referred to as government transfers.

Government transfers and associated externally restricted investment income are recognized as deferred contributions if the eligibility criteria for use of the transfer, or the stipulations together with the Corporation's actions and communications as to the use of the transfer, create a liability. These transfers are recognized as revenue as the stipulations are met and, when applicable, the Corporation complies with its communicated use of these transfers.

Notes to the Financial Statements

Canadian Energy Centre Ltd.
Year ended March 31, 2021

Note 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (Cont'd)

(a) Basis of Financial Reporting (Cont'd)

All other government transfers, without stipulations for use of the transfer, are recognized as revenue when the transfer is authorized, and the Corporation meets the eligibility criteria (if any).

Expenses

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

Valuation of Financial Assets and Liabilities

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

Financial Statement Component	Measurement
Cash and cash equivalents	Cost
Accounts receivable	Lower of cost or net recoverable value
Accounts payable and accrued liabilities	Cost

The Corporation does not have any financial instruments classified in the fair value category and does not hold derivative contracts. Therefore, these statements do not present a statement of remeasurement gains and losses as the Corporation is not exposed to remeasurement gains and losses.

Financial Assets

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

Notes to the Financial Statements

Canadian Energy Centre Ltd.
Year ended March 31, 2021

Note 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (Cont'd)

(a) Basis of Financial Reporting (Cont'd)

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

Cash and cash equivalents
Cash comprises of cash on hand and demand deposits. Cash equivalents are short-term, highly liquid, investments that are readily convertible to known amounts of cash and that are subject to an insignificant risk of change in value. Cash equivalents are held for the purpose of meeting short-term commitments rather than for investment purposes.

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

Liabilities

Liabilities are present obligations of the Corporation to external entities and individuals arising from past transactions or events occurring before the year end, the settlement of which is expected to result in the future sacrifice of economic benefits. They are recognized when there is an appropriate basis of measurement and management can reasonably estimate the amounts.

Non-Financial Assets

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

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

Non-financial assets are limited to prepaid expenses.

Notes to the Financial Statements

Canadian Energy Centre Ltd.
Year ended March 31, 2021

Note 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (Cont'd)

(a) Basis of Financial Reporting (Cont'd)

Tangible Capital Assets
Tangible capital assets are recognized at cost less accumulated amortization, which includes amounts that are directly related to the acquisition, design, construction, development, improvement, or betterment of the assets. Cost includes overhead directly attributable to construction and development, as well as interest costs that are directly attributable to the acquisition or construction of the asset. The cost, less residual value, of the tangible capital assets, excluding land, is amortized on a straight-line basis over their estimated useful lives.

The capitalization threshold for all capital assets is $2,000. The Corporation, however, does not have any capital assets. Therefore, there is no tangible capital assets reported in the financial statements.

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

Measurement Uncertainty

The World Health Organization declared on March 11, 2020 the outbreak of a strain of the novel coronavirus ("COVID-19") as a pandemic which has resulted in a series of public health and emergency measures that have been put in place to combat the spread of the virus and provide financial assistance, as necessary. The duration and impact of COVID-19 are unknown at this time and it is not possible to reliably estimate the effect these developments will have on the Corporation's financial statements.

Note 3 FUTURE CHANGES IN ACCOUNTING STANDARDS

The Public Sector Accounting Board has approved the following accounting standards:

- **PS 3280 Asset Retirement Obligations (effective April 1, 2022)**
  This standard provides guidance on how to account for and report liabilities for retirement of tangible capital assets.

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

Notes to the Financial Statements

Canadian Energy Centre Ltd.
Year ended March 31, 2021

Note 3 FUTURE ACCOUNTING CHANGES (Cont'd)

The Corporation has not yet adopted these standards. Management is currently assessing the impact of these standards on the Corporation's financial statements.

Note 4 BUDGET

A budgeted deficit of $1,146,957 was approved by the Board on March 30, 2020. In addition, $1,881,970 was approved by the board for additional expenses - which brought the total budget expenses to $4,702,370. The budget reported in the Statement of Operations reflects the original Corporation deficit and additional reclassifications required for more consistent presentation with current and prior year results.

	Year ended March 31, 2021
Communications and Marketing	$ 1,854,000
Salaries and Benefits	1,680,000
Contingency - Other	317,370
Office Infrastructure	186,000
Accounting	150,000
Research External	150,000
Social Advertising	130,000
Website	100,000
Legal	60,000
Research Internal	30,000
General and Administrative Expenses	27,000
Information Technology	18,000
TOTAL EXPENSES	**$ 4,702,370**

Notes to the Financial Statements

Canadian Energy Centre Ltd.
Year ended March 31, 2021

Note 5 CASH AND CASH EQUIVALENTS

Cash and cash equivalents consist of:

	2021	2020
Cash	$ 1,846,504	$ 2,707,258
	$ 1,846,504	**$ 2,707,258**

Note 6 ACCOUNTS RECEIVABLE

Accounts receivable are unsecured and non-interest bearing.

	2021	2020
Accounts receivable:		
Due from the Government of Alberta	$ -	$ 1,000,000
GST Receivable	99,875	68,576
Balance at end of year	**$ 99,875**	**$ 1,068,576**

Note 7 FINANCIAL RISK MANAGEMENT

The Corporation is exposed to some financial risks. These financial risks include credit risk and liquidity risk.

(a) Credit Risk

Credit risk is the risk of loss arising from the failure of a counterparty to fully honour its financial obligations with the Corporation. Credit risk on accounts receivable is considered low.

As of March 31, 2021, 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 adequate grants from the Ministry. The Corporation manages liquidity risks by its budget processes and

Notes to the Financial Statements

Canadian Energy Centre Ltd.
Year ended March 31, 2021

Note 7 FINANCIAL RISK MANAGEMENT (Cont'd)

regularly monitoring cash flows to ensure the necessary funds are on hand to fulfill upcoming obligations, including operating expenses.

Note 8 ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	2021	2020
Accounts Payable	$ 473,643	$ 512,754
Accrued Accounts Payable	472,731	168,053
ATB Alberta Rewards Business Card	8,436	10,263
Accrued Salaries and Wages	-	53,719
Vacation Payable	60,869	26,803
Balance at end of year	**$ 1,015,679**	**$ 771,592**

Note 9 ACCUMULATED SURPLUS

Accumulated surplus is comprised of the following:

	2021	2020
Balance at beginning of year	$ 3,035,727	$ -
Annual (deficit) / surplus	(2,061,540)	3,028,927
	974,187	**3,028,927**
Share capital:		
1 Common Share	-	6,800
	-	**6,800**
Balance at end of year	**$ 974,187**	**$ 3,035,727**

Note 10 SHARE CAPITAL

Share capital is comprised of the following:

	2021	2020
Issued:		
1 Common Share	$ 6,800	$ 6,800
Balance at end of year	**$ 6,800**	**$ 6,800**

Notes to the Financial Statements

Canadian Energy Centre Ltd.
Year ended March 31, 2021

Note 11 CONTINGENT LIABILITIES

As of March 31, 2021, the Corporation was not named as defendant in any specific legal actions.

Note 12 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.

	2021	2020
Obligations under contracts	$ 269,950	$ 260,304
Balance at end of year	**$ 269,950**	**$ 260,304**

Estimated payment requirement for the next one year is as follows:

	Contracts	Total
2021-2022	$ 269,950	$ 269,950
	$ 269,950	$ 269,950

Note 13 APPROVAL OF FINANCIAL STATEMENTS

The Board approved the financial statements of the Corporation.

Schedule 1 - Expenses - Detailed by Object

Canadian Energy Centre Ltd.
Year ended March 31, 2021

	2021		October 9, 2019 To March 31, 2020
	Budget	**Actual**	**Actual ***
Salaries and Benefits	$ 1,680,000	$ 1,630,505	$ 495,849
Communications and Marketing	1,854,000	1,204,560	1,011,229
Social Advertising	130,000	294,889	78,919
Accounting	150,000	150,000	62,500
Contingency - Other	317,370	123,517	-
Research External	150,000	106,338	21,545
Office Infrastructure	186,000	78,225	36,579
Website	100,000	76,536	90,259
Legal	60,000	34,050	51,612
Research Internal	30,000	20,770	3,394
General and Administrative Expenses	27,000	9,593	107,958
Information Technology	18,000	6,000	11,229
Total Expenses	**$ 4,702,370**	**$ 3,734,983**	**$ 1,971,073**

* 2020 numbers have been reclassified for more consistent presentation with current and prior period results.

Schedule 2 - Salary and Benefits Disclosure

Canadian Energy Centre Ltd.
Year ended March 31, 2021

	2021			For the Period October 9, 2019 To March 31, 2020
	Base Salary (1)	Other Cash Benefits (2)	Total	Total
Chief Executive Officer (CEO) (3)	$ 194,252	$ 46,620	$ 240,872	$ 115,804
Executive Director (4)	171,600	41,184	212,784	71,201
Executive Director (5)	171,600	41,184	212,784	38,465
Total Expenses	**$ 537,452**	**$ 128,988**	**$ 666,440**	**$ 225,470**

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 and health benefits. No bonuses were paid during the year.

(3) CEO was hired on October 9, 2019 with an annual base salary of $194,252 and additional 14% and 10% of the annual base salary in lieu of pension and health benefits, respectively.

(4) Executive Director was hired on December 1, 2019 with an annual base salary of $171,600 and additional 14% and 10% of the annual base salary in lieu of pension and health benefits, respectively.

(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.

Schedule 3 - Related Party Transactions

Canadian Energy Centre Ltd.
Year ended March 31, 2021

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:

	2021	For the Period October 9, 2019 To March 31, 2020
Revenues		
Grants	$ 1,673,443	$ 5,000,000
	$ 1,673,443	$ 5,000,000
Expenses		
Rent	$ 57,354	$ 30,498
Insurance coverage	1,394	-
	$ 58,748	$ 30,498
Receivable from the Department of Energy	$ -	$ 1,000,000
Common Shares - Department of Energy	$ 6,800	$ 6,800
Payable to Alberta Infrastructure	$ 20,074	$ 25,222

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
Year Ended March 31, 2021

(in thousands)

	Voted Estimate [1]	Supplementary Estimate [2]	Adjusted Voted Estimate	Voted Actuals [3]	Over Expended (Unexpended)
EXPENSE VOTE BY PROGRAM					
Ministry Support Services					
1.1 Minister's Office	$ 995	$ -	$ 995	$ 872	$ (123)
1.2 Associate Minister's Office	572	-	572	521	(51)
1.3 Deputy Minister's Office	667	-	667	606	(61)
1.4 Associate Deputy Minister's Office	552	-	552	497	(55)
1.5 Corporate Services	4,082	-	4,082	2,860	(1,222)
	6,868	-	6,868	5,356	(1,512)
Resource Development and Management					
2.1 Energy Operations	19,370	(272)	19,098	15,448	(3,650)
2.2 Energy Policy	36,498	(272)	36,226	33,940	(2,286)
2.3 Industry Advocacy	30,000	(1,000)	29,000	1,673	(27,327)
	85,868	(1,544)	84,324	51,061	(33,263)
Cost of Selling Oil					
3 Cost of Selling Oil	84,000	(28,000)	56,000	46,308	(9,692)
	84,000	(28,000)	56,000	46,308	(9,692)
Climate Change					
4.1 Renewable Electricity Program	2,862	8,938	11,800	2,335	(9,465)
	2,862	8,938	11,800	2,335	(9,465)
Economic Recovery Support					
5.1 Site Rehabilitation Program	-	251,000	251,000	129,640	(121,360)
5.2 Alberta Energy Regulator Levy Assistance	-	113,000	113,000	113,000	-
	-	364,000	364,000	242,640	(121,360)
Market Access					
6.1 Crude by Rail	-	445,000	445,000	442,530	(2,470)
	-	445,000	445,000	442,530	(2,470)
Total	$ 179,598	$ 788,394	$ 967,992	$ 790,230	$ (177,762)
Encumbrance/(Lapse)					$ (177,762)
CAPITAL INVESTMENT VOTE BY PROGRAM					
Ministry Support Services	500	-	500		(500)
	$ 500	$ -	$ 500	$ -	$ (500)
Encumbrance/(Lapse)					$ (500)
FINANCIAL TRANSACTIONS VOTE BY PROGRAM					
Climate Change	96,970	-	96,970	97,683	713
	$ 96,970	$ -	$ 96,970	$ 97,683	$ 713
					$ 713
NET LOANS AND ADVANCES FOR SHORT TERM LENDING					
Economic Recovery Support	-	104,000	104,000	37,148	(66,852)
	$ -	$ 104,000	$ 104,000	$ 37,148	$ (66,852)
Encumbrance/(Lapse)					$ (66,139)

(1) As per “Expense Vote by Program” ,“Capital Investment Vote by Program” and “Financial Transaction Vote by Program” page 87 and 88 of the 2020-21 Government Estimates.

(2) Supplementary Supply Estimates approved on November 24, 2020 and March 11, 2021.

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 for the Department of Energy between April 1, 2020 and March 31, 2021.